Project design document form for CDM project activities

(Version 05.0)

PROJECT DESIGN DOCUMENT (PDD)	
Title of the project activity	Afam Combined Cycle Gas Turbine Power Project
Version number of the PDD	10
Completion date of the PDD	23/02/2015
Project participant(s)	**The Shell Petroleum Development Company of Nigeria Limited (SPDC)** SPDC is a joint venture between: Nigerian National Petroleum Corporation (NNPC) 55% Shell Nigeria (a subsidiary of Royal Dutch/ Shell plc) 30% Elf Petroleum Nigeria Limited (EPNL, a subsidiary of TOTAL S A) 10% Agip (a subsidiary of ENI SpA) 5%
Host Party	Nigeria
Sectoral scope and selected methodology(ies), and where applicable, selected standardized baseline(s)	Sectoral scope 1: Energy generation, supply and transmission and distribution, AM0029 “Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas”
Estimated amount of annual average GHG emission reductions	550 234 tCO_2

SECTION A. Description of project activity

A.1. Purpose and general description of project activity

The “project activity”, called Afam VI (“the project”) is a 650 MW grid-connected combined-cycle gas turbine (CCGT) fuelled by natural gas. It is a build-own-operate power plant at Afam in Rivers State, Nigeria.

The power plant site is near to existing electricity generation plant that is now non-operational, which existed prior to the start of implementation of the project activity, and which is owned by the Power Holding Company of Nigeria (PHCN), the successor to the National Electric Power Authority (NEPA). This older plant originally comprised four old, small open-cycle gas turbine (OCGT) units called Afam I-IV, consisting of around 75 MW of installed capacity, which are decrepit, beyond repair and have not been operated for many years. The site also contained an OCGT facility called Afam V, which was commissioned in 2002, consisting of 2 x 137 MW Siemens V94.2s gas turbines. These units are not in operational condition due to inadequate maintenance and poor operating practices.

The project is expected to reduce greenhouse emissions from power generation by over 500 000 tCO_2 per year, compared with the alternative plant that would have been built and operated in the absence of the project activity.

The project activity reduces greenhouse gas emissions because the CO_2 volumes emitted for each unit of electricity generated by the CCGT plant are lower than the quantity of CO_2 emissions that would otherwise be emitted by generating the same quantity of electricity from the baseline OCGT plant. Because the fuel is the same (natural gas), the emission reduction arises from the greatly improved thermal efficiency. The project will not displace other generation on the grid in Nigeria because there is a generation capacity deficit on the grid.

This is a conservative way to view the baseline. The alternative would be to consider the self-generation of electricity from small diesels that are not dispatched as part of the grid, but that may be expected to be displaced by the electricity from the project activity. This approach was considered by the project participants and included in the calculations of the choice of baseline emission factors. The Afam project was planned from the outset taking into account both the objective of minimising CO_2 emissions and of the need for certified emission reductions (CERs) to offset the additional investment required to minimise CO_2 emissions. In 2005, the lead project participant engaged consultants with the assistance of the World Bank/ GGFR for advice on methodologies and a project design document for the project. A baseline consisting of small diesel plant was considered as the baseline in considerable detail, and a new methodology was proposed for this purpose (NM0208). Elements from that proposed methodology were adopted by the Meth Panel and incorporated into the ‘Tool to calculate the emission factor of an electricity system’ (rather than approving the methodology for stand-alone use). This project design document (PDD) uses the alternative plant as the baseline. Compared with small diesels (build margin) and operating margin calculations, this represents a considerably more conservative (lower emission) baseline.

Using the methodology and the relevant tools as guides for calculating the GHG reductions, the estimated **annual GHG reduction** is 550 234 tons of CO_2, which is expected to remain stable over the ten year crediting period.

The project activity will make a valuable contribution to sustainable development in Nigeria.

Firstly, the new capacity addition to the grid will reduce the severe generation capacity deficit on Nigeria's electricity grid, thus improving its reliability. This deficit is exacerbated by the chronic unavailability of a significant proportion of installed capacity due to the poor state of repair of thermal stations and because hydro stations are affected by water level fluctuation and limitations on water availability. Because of the capacity deficit, it is expected that, in practice, the project will help to displace a portion of more emissions-intensive small diesel-fired engines currently providing power to many grid connected customers, who prefer this costly option because of the unreliability of grid generation. For conservativeness and in line with the methodological tool "tool for calculating emission factor for an electricity system", a lower alternative project baseline has been selected in this PDD.

Second, the project will help improve the overall access to electricity for the people of Nigeria, particularly in the Niger Delta. At present, the country's annual per capita electricity consumption is just over 100 kWh.[1] This represents a very low level of development, on the threshold of *Survival*, where people's main concerns are simply food, water and shelter, and where health services are minimal.[2]

Thirdly, the project development has provided important employment, training and development opportunities for the local community. A total of 877 (678 skilled, 131-semi-skilled and 69 unskilled) persons, mainly from the neighbouring communities are to be employed by the project during construction phase. Once in operation, the project will employ 50 skilled persons. These jobs will continue over the estimated project duration (20 years). As part of the project development, 140 youths from neighbouring communities will be given workforce training in areas such as welding to enable them acquire skills that will open up future employment opportunities to them. It will also facilitate technology transfer by building up the capacity in Nigeria for the operation of CCGT power plants.

Finally, the project also involves the upgrading of around 100km of ageing power lines to enhance the connection of 16 communities to power. While the electricity consumption of these communities will be relatively small compared with the capacity of the plant, these connections will contribute to sustainable community development. The current lack of electricity in some areas results in the burning of wood, charcoal and liquid fuels for basic daily needs such as cooking and lighting. Electricity can meet these needs more safely (by reducing the risk of fire and of burns to small children) and with none of the adverse health and social impacts (e.g. indoor air pollution, the amount of time spent collecting firewood and deforestation) that arise from the current fuels used. These are important benefits in addition to the contribution to improved education and incomes mentioned above. Therefore, to the extent that some of the electricity generated may meet previously unmet demand, it will contribute to sustainable development in Nigeria.

A.2. Location of project activity

A.2.1. Host Party

[1] US DOE EIA estimates final end consumption in Nigeria to be 15.85 billion kWh. Nigeria's population is around 150 million people (CIA World Factbook). This gives a figure of around 106 kWh per capita.

[2] Based on Starr, C (1997) "Sustaining the human environment: the next two hundred years" Daedalus, Vol. 125. The analysis presented by Starr suggested the following categories for per capital electricity consumption: 10^2 = Survival (Food, water, shelter, minimal health services); 10^3 = Basic Quality of Life (literacy, life expectancy, sanitation, infant mortality, physical security, social security):

The Federal Republic of Nigeria.

A.2.2. Region/State/Province etc.

The Afam power plant is located in Rivers State.

A.2.3. City/Town/Community etc.

The project is located in the Oyigbo Local Government Area (LGA) of Rivers State. The LGA headquarters are in Okoloma. The Afam power development area is bounded to the north by Imo River, to the east by a Ayama village, to the south by a Egberu village and to the west by Obiama-Asa village.

A.2.4. Physical/Geographical location

The project is approximately 30 km northeast of Port Harcourt, the capital of Rivers State, and lies roughly between 7.2545 E, 4.8480 N and 7.2600 E, 4.8525 N decimal degrees respectively. The project site covers 22.67 ha.

Figure 1 shows a map of the Afam VI project site and surrounding area; Figure 2 shows a plot plan of the site layout. Figure 3 shows a map of the Nigerian transmission and distribution grid and its clear delineation.

Figure 1: Map of the Afam VI project site and surrounding area

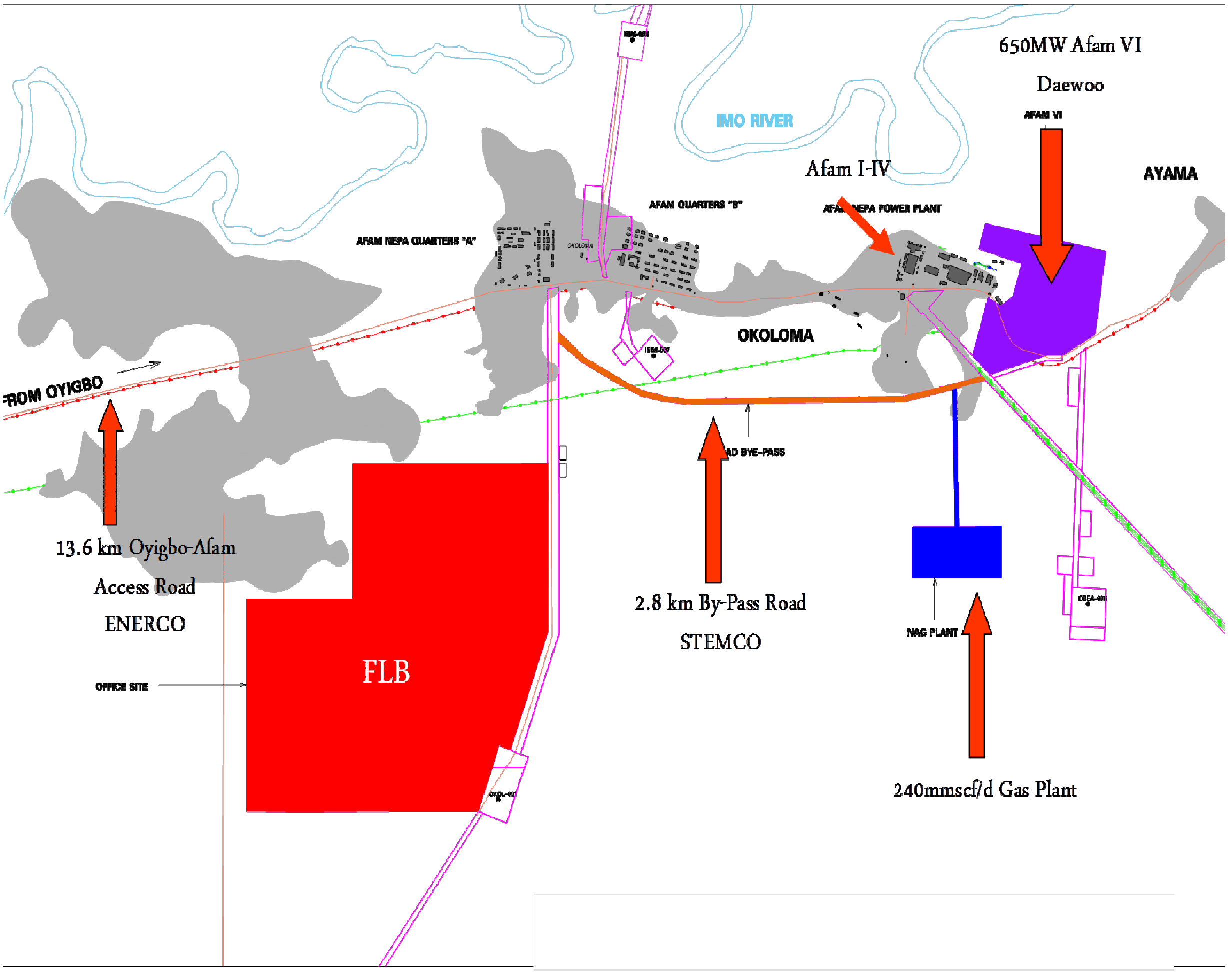
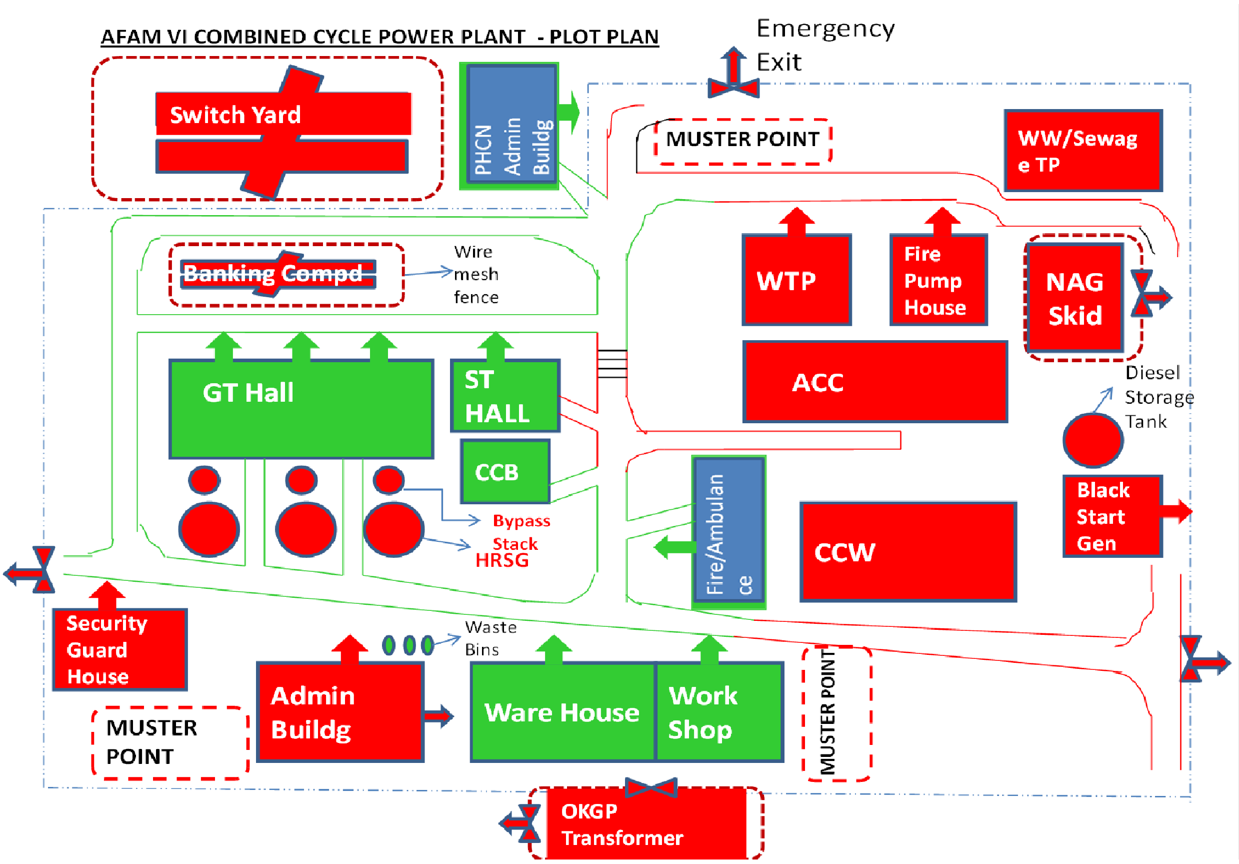
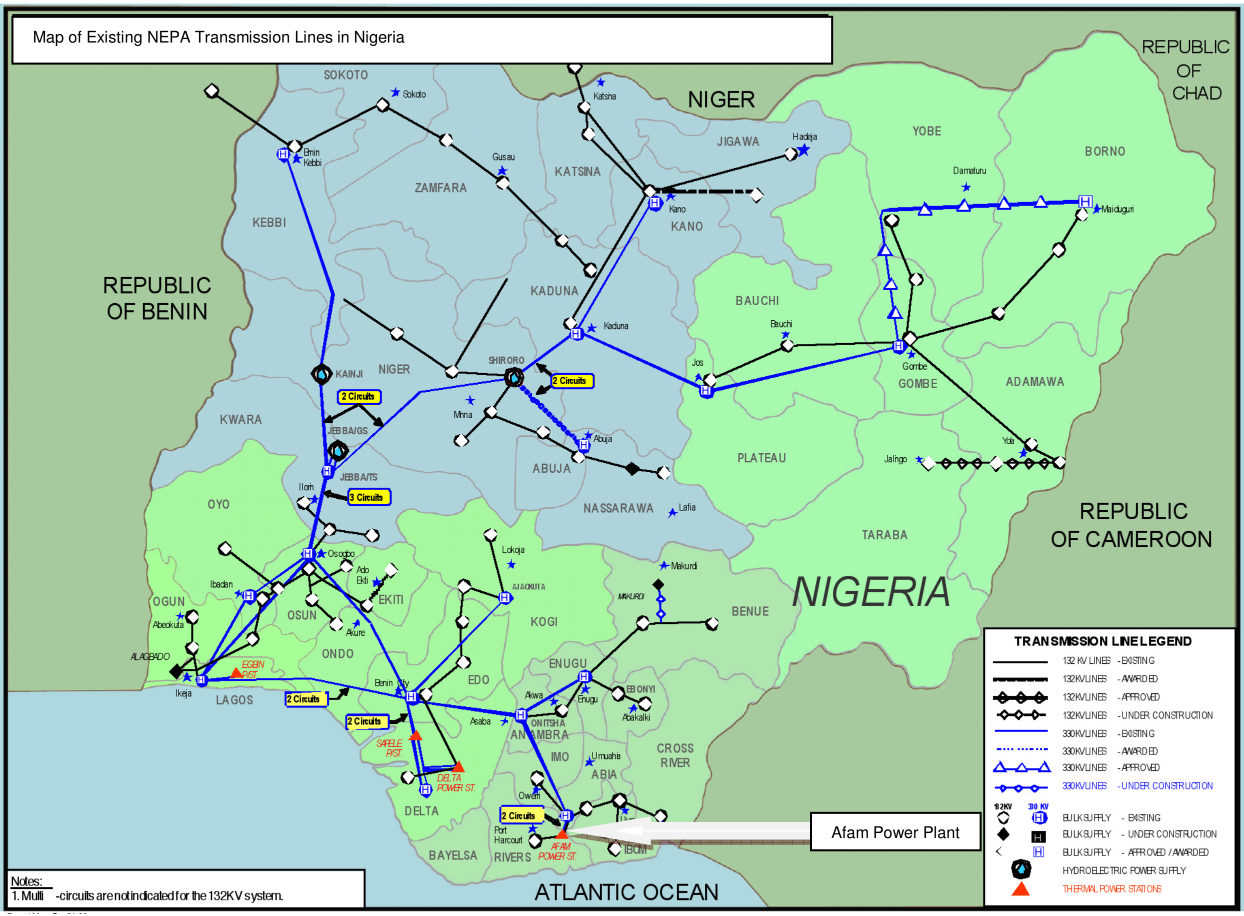


Figure 2: Plot plan showing layout of the Afam VI project site



WTP = Water treatment Plant
ACC = Air Cooled Condenser
CCW = Closed Cooling Water system
CCB = Central Control Building
WW/Sewage TP = Waste Water/Sewage Treatment Plant
GT = Gas Turbine
ST + Steam Turbine
NAG = Non Associated Gas

Figure 3: Map of Existing NEPA Transmission Lines in Nigeria[3]



A.3. Technologies and/or measures

The project activity involves reducing emissions from electricity generation by enhancing the performance of gas-fired power generation plants that provide electricity to the Nigerian grid. The history and status of power generation at the Afam site is outlined below (Table 1).

Table 1: Background to generating units at Afam power plant

	Year commission	Size	Type	STATUS	Owner/ operator
Afam I	1962	4 x 13.5 MW (~56 MW)	OCGT	Explosion in 1997. Out of use since then and subsequently scrapped due to obsolescence	PHCN
Afam II	1976	4 x 23.9 MW (~92 MW)	OCGT	Explosion in 1997. Out of use since then. Planned rehabilitation of 2 units in 2011.	PHCN

[3] *gtz2009 en-regionalreport-wa-nigeria, Regional Report on Renewable Energies in West Africa, Potentials and Markets – 17 Country Analyses*

Afam III	1978	4 x 27.5 MW (~112 MW)	OCGT	Explosion in 1997. All units broken down with one of the units down on broken turbine compressor blades.	PHCN
Afam IV	1982	6 x 75 MW (~450 MW)	OCGT	Explosion in 1997 2 units partially worked for a while thereafter before falling into disrepair. All are down due to broken turbine compressor blades. Planned reconditioning of these units in 2011.	PHCN
Afam V	2001	2 x 138 MW (~276 MW)	OCGT	Failed in 2005 due to lack of maintenance and have not worked properly since	PHCN
Afam VI	GTs – 07/09 ST – 12/10	3 x 150 MW 1 x 200 MW (~650 MW)	CCGT	This project activity	SPDC

* The entire NEPA Afam I-IV Station shut down in 1997 except for Afam V which was shut down in 2005 due to poor maintenance. Practically, all the units were run far in excess of the recommended running hours before overhaul. Afam I-V are not in operation due to poor maintenance, and are undergoing rehabilitation by PHCN to add somewhere between 270-403 MW of capacity (see: The Nigerian Voice (2010) *PHCN begins work on Afam I-IV power plant*. 4 May 2010; and, Federal Presidency of Nigeria (2010) *Roadmap for Power Sector Reform*. August 2010. Chapter 3, pg 51 outlines the status of Afam plants in 2010.

The design calls for technology of an international standard to be implemented, as specified in the Environmental Impact Assessment and consistent with the project participants' environment, health and safety practices. The Afam VI gas turbines will be installed with dry low NO_X combustion equipment. The height of the exhaust stacks is specified in the Environmental Impact Assessment to ensure that emissions and prevailing ambient air quality will comply with the Laws of Nigeria, all relevant Consents and World Health Organisation and World Bank guideline limits at the time of financial commitment.

Technology transfer
The operation of a combined cycle plant is considerably more technically complex than an open cycle plant. To ensure the transfer of new skills, Nigeria is actively involved in the project through National Petroleum Investment Management Services (NAPIMS), which is part of the Nigerian National Petroleum Company (NNPC). The design, construction and operation of the project involve international staff working with local Nigerian staff, ensuring sustainable knowledge transfer. In addition to NAPIMS involvement, SPDC employs many Nigerian nationals as engineers and other professionals who are actively engaged on the project.

A.4. Parties and project participants

Party involved (host) indicates 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)

Nigeria (host Party)	**The Shell Petroleum Development Company of Nigeria Limited (SPDC).** SPDC is a joint venture between: • Nigerian National Petroleum Corporation (NNPC) 55% • Shell Nigeria (a subsidiary of Royal Dutch/ Shell plc) 30% • Elf Petroleum Nigeria Limited (EPNL, a subsidiary of TOTAL S A) 10% Agip (a subsidiary of ENI SpA) 5%	No

A.5. Public funding of project activity

No public funding has been used for the project.

SECTION B. Application of selected approved baseline and monitoring methodology and standardized baseline

B.1. Reference of methodology and standardized baseline

Title: Approved baseline and monitoring methodology AM0029 (Version 03), "Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas". This PDD also makes use of Version 06.0.0 of the "Tool for the demonstration and assessment of additionality" and of Version 2.2.1 of the methodological tool "Tool to calculate the emission factor for an electricity system".

B.2. Applicability of methodology and standardized baseline

The project activity meets the applicability criteria set out in AM0029:

- The project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant.
- The geographical/ physical boundaries of the baseline grid can be identified and information pertaining to the grid and estimating baseline emissions is publicly available.[4]

[4] Estimating baseline emissions in this case does not require the *ex post* estimation of a grid emission factor. Nigeria does not have sufficient installed generating capacity to meet demand and therefore new plants need to be dispatched to the maximum extent possible: they do not displace other grid-connected (i.e. centrally-dispatched) plants. Many consumers in Nigeria – particularly industry and large commercial buildings, but also households who can afford the generators and the fuel – have their own diesel generators to supplement the grid when supply is interrupted, or as a far more expensive but more reliable alternative to grid-supply. Therefore, in practice, the project is expected to displace high emissions from diesel reciprocating engine generators on consumers' sites. However, this PDD is based on the more conservative baseline of the alternative power plant technology, which is gas-fired OCGT. Therefore, the actual emission reductions will be larger than those calculated under this PDD.

- Natural gas is sufficiently available in the Rivers States region of Nigeria, and there is significantly greater scope for the expansion of gas-fired grid-connected power in the region such that 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. Therefore, 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.

Table 2: Demonstration of project applicability

Applicability criteria	Project activity applicability
The project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant. Natural gas should be the primary fuel[5].	The project activity is the construction and operation of a new 650 MW combined cycle gas turbine (CCGT) plant, comprising 3 x 150 MW gas turbines and 1 x 200 MW steam turbine. The electricity generated will be supplied to the regional power grid and natural gas sourced from the regional gas grid will be the primary fuel. No auxiliary fuel (e.g. diesel) will be used as part of the project activity; the project activity will be fully fired by natural gas in CCGT mode.
The geographical/ physical boundaries of the baseline grid are clearly identified and information pertaining to the grid and estimating baseline emissions is publicly available.	Nigeria's electricity grid is severely constrained. With only 3.8 GW grid capacity against an estimated demand of 10 GW, Nigeria has considerable suppressed and unmet demand[6] with only around 40% of Nigeria's population of 150 million people having access to electricity[7]. Furthermore, much of the installed capacity is unavailable due to the poor state of repair of thermal stations and also because hydro-electric power stations are affected by fluctuations in water level and limitations to water availability. Just over 2 GW of the installed generation capacity is currently available to generate at any given time. Consequently, the grid is plagued by poor power quality (such as under-voltage conditions) and frequent power outages of long duration because load shedding is required to balance supply and demand. In response, most industrial and commercial business customers, and residential customers with sufficient capital, have invested in their own diesel generators. Survey data shows that these generators range in size from 1 kVA up to over 3 800 kVA per unit. There is estimated to be some 3.6 GW of non-residential diesel generation capacity and 900 MW of residential diesel generation capacity.[8] Although the cost of operating these units is higher than the grid tariff, they provide a reliable supply when it is needed, which is essential for business operation. Information relating to the state of the Nigerian electricity grid, including the existing supply constraints and demand deficit are publicly available. The extent and geographic boundaries of the grid are shown in Figure 3.

[5] Small amounts of other start-up or auxiliary fuels can be used, but can comprise no more than 1% of total fuel use, on an energy basis.

[6] See: Prasad. V.S.N. Tallapragada (2008) Nigeria's Electricity Sector - Electricity and Gas Pricing Barriers, International Association for Energy Economics, Cleveland, USA.

[7] See: BP Statistical Review of World Energy, June 2011.

[8] See: J. Ikeme and Ebohon J. O (2005) Nigeria's electric power sector reform: what should form the key objectives? Energy Policy, Vol. 33 (9) pp. 1213-1221.

Applicability criteria	Project activity applicability
Natural gas is sufficiently available in the region or country.	**Natural gas supply in Nigeria** Latest statistics (June 2011) suggests that Nigeria has the 9th largest proven gas reserves in the world, with 187 trillion cubic feet (Tcf) of proven high grade natural gas[9]. The majority of the natural gas reserves are located in the Niger River Delta. In 2007, Nigeria produced 1 204 billion cubic feet (Bcf) of natural gas, while consuming 456 Bcf. Following supply constraints due to underinvestment, in February 2008 the Nigerian government approved a package of measures to improve the medium- to long-term development of the gas sector that included a new gas pricing policy and a Gas Master Plan that identifies the future gas infrastructure network to be built by potential investors and promotes new gas-fired power plants to help reduce gas flaring and provide much-needed electricity generation. The short/medium term gas supply plan was to triple production capacity to 2 042 MMscf/d by the end of 2009 to enable total gas-fired generating capacity to grow to over 6,000MW by the end of 2009.[10] Since then, the Government of Nigeria has revised the short-term goals of the Gas Master Plan to a supply of natural gas of 1 636 MMscf/d by April 2011, with a view to supporting circa 7 000 MW of electricity generation capacity;[11] there is no up-to-date data available to corroborate whether this goal has been met. The supply plan aims to ensure that domestic gas demand is met, and provisions are made to prioritise domestic supply over LNG exports.
Natural gas is sufficiently available in the region or country. (cont'd.)	**Natural gas supply in the region** In the Rivers State region where the project is located, around 30-40 MMscf/d of associated gas and 180 MMscf/d of non-associated gas is available to the regional gas network operated by the Nigerian Gas Company (NGC) serving a maximum domestic demand of 150-180 MMscf/d. In addition, the Okoloma gas plant (adjacent to the Afam gas and power project and supplying gas since October 2008) has a production capacity of 240 MMscf/d of non-associated gas. In addition, the project is connected to the NGC regional gas network. The capacity of Afam VI is not constrained by the production capacity of the Okoloma development; the gas production capacity from Okolama will be sufficient to supply over 2 GW of new CCGT capacity or about 1.5 GW of OCGT capacity. Natural gas is therefore abundantly available in the region to meet the project activity requirements. The project activity does not constrain future capacity additions in the area, as evidenced by the fact that other natural gas based power plants have recently been built and are planned in the region, for example by Total at the Obite power plant located in OML 58 (planned) and by Eni at Okpai.[12] On the basis of the above, it can be concluded that the project would not give rise to price- inelastic gas supply constraints during the crediting period which could result in significant leakage impacts.

[9] See: http://www.eia.doe.gov/emeu/cabs/Nigeria/NaturalGas.html. US Energy Information Administration, 2009.

[10] See: Prasad. V.S.N. Tallapragada (2008) Nigeria's Electricity Sector - Electricity and Gas Pricing Barriers, International Association for Energy Economics, Cleveland, USA.

[11] Federal Presidency of Nigeria (2010) *Roadmap for Power Sector Reform*. August 2010. Chapter 2, pg 10.

[12] The Obite power project is being developed by Total in OML58, see http://www.total.com/en/our-energies/natural-gas-/power-generation-940907.html. Total launched a call for tender for support for the CDM aspects of the Obite project in May 2011. The Okpai power project received CDM support through a flare reduction project at the Kwale - see CDM project reference 0553, registered 9th November 2006. Other major CCGT power projects under development include Omoku and Alaoji, both located in Rivers State.

B.3. Project boundary

The emission sources in the project boundary are as follows:

- Emissions from the combustion of natural gas in the Afam VI plant.
- The amount of electricity exported to the electricity grid from the Afam VI plant.

The amount of electricity generated is used to determine the emission reductions achieved by operating the Afam VI plant in combined cycle mode compared with the baseline scenario of an open-cycle plant of equivalent output capacity.

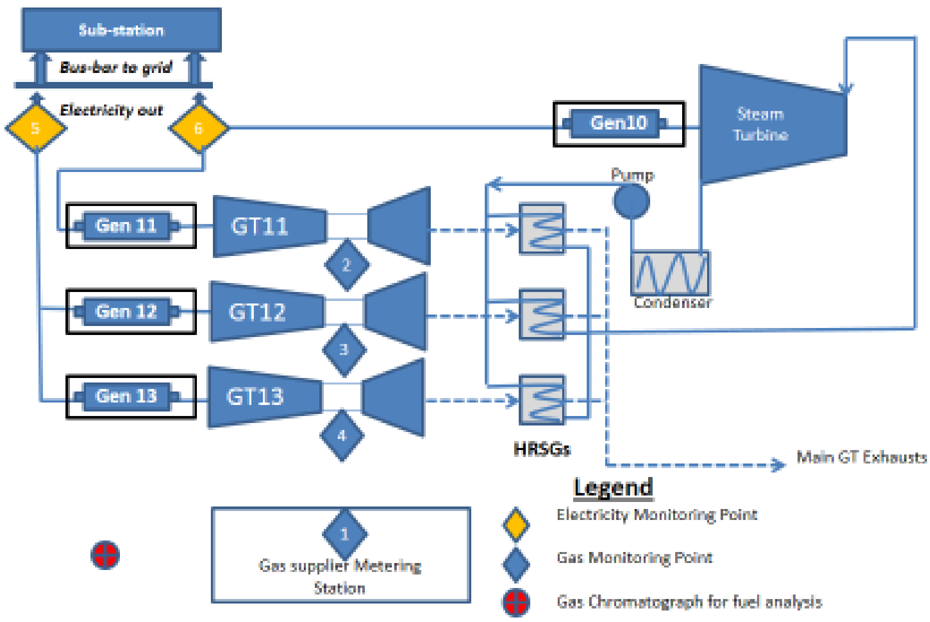
Table 3 shows the emission sources and gases included in or excluded from the project boundary.

Table 3: Emissions sources included in or excluded from the project boundary

Source		GHGs	Included?	Justification/Explanation
Baseline scenario	OCGT power generation	CO_2	Yes	Main emissions source in the baseline
		CH_4	No	Excluded for simplification.
		N_2O	No	Excluded for simplification.
Project scenario	CCGT power generation	CO_2	Yes	Main source of emissions in the project activity.
		CH_4	No	Excluded for simplification.
		N_2O	No	Excluded for simplification.

Figure 4 shows the project boundary.

Figure 4: Schematic illustration of the project activity within CDM project boundary



B.4. Establishment and description of baseline scenario

In the baseline activity, 650 MW of OCGT generating capacity would be required to generate the equivalent amount of electricity.

The methodology requires project participants to use the following steps to identify 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 described below.

Step 1: Identify plausible baseline scenarios

The methodology requires that 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. These alternatives are required to be in compliance with all applicable legal and regulatory requirements. Therefore, the following options have been assessed:

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

The analysis provided below assesses the following three critical criteria required by the methodology for identifying 'plausible baseline scenarios' from a total of nine 'potential plausible baseline scenarios' identified in accordance with the above options:

1. Compliance with applicable legal and regulatory requirements
2. Is the baseline scenario 'realistic and credible' and
3. If implemented, could the alternative deliver outputs comparable to the CDM project activity?

Note on criteria used to determine 'plausible baseline scenarios'

Plausible options should be in compliance with the state and national policies relating to power generation and distribution. Options considered 'realistic and credible' include those alternatives for which the technology is commercially established and available; those alternatives which are within the investment capacities of the promoters; those alternative technologies that are prevailing; and/or power plant technologies that have recently been constructed or are under construction or are being planned. Options that might deliver outputs comparable to the CDM project activity might include those alternatives that provide similar output in terms of the peak load factor, peak versus base load power and power quality; and/or those alternatives for which the cost of generation is lower than grid power.

Table 4: Consideration of baseline scenario options

Scenario description	Compliance with applicable legal and regulatory requirements?	Realistic and credible?	Outputs comparable to the CDM project activity?	Conclusion on plausibility as baseline scenario
Option 1: *Project activity not implemented as a CDM project*				
Natural gas power generation using combined cycle (CCGT) technology without CDM Efficiency: 50% Lifetime: 20+ years	Yes	There are other CCGT power plants operating in Nigeria (typically connected with CDM investments). These include at Kwale/Okpai and Obite (planned). Other projects being developed by NDPHC (Omoku and Alaoji)	Yes	Plausible baseline scenario
Option 2: *Power generation using natural gas, but technologies other than the project activity*				
Natural gas power generation using open cycle (OCGT) Efficiency: 36% Lifetime: 20+ years	Yes	Yes, OCGT is an established power generation technology that is usually favoured in the region where gas is available due to low capital costs (relative to CCGT and other fuel options), low national gas prices and simpler operation and maintenance needs. The Nigerian Government has approved the building of a number of open cycle gas turbine plants[13].	Yes, due to the grid capacity deficit, OCGT would operate as base-load plant on the Nigerian grid	Plausible baseline scenario

[13] See: http://www.mbendi.com/indy/powr/af/ng/p0005.htm.

Scenario description	Compliance with applicable legal and regulatory requirements?	Realistic and credible?	Outputs comparable to the CDM project activity?	Conclusion on plausibility as baseline scenario
Option 3: *Power generation using coal*				
Coal-fired power generation using conventional steam cycle Efficiency: 36% Lifetime: 20-30 years	Yes (subject to potential application of atmospheric pollution controls)	No. Whilst Nigeria holds significant coal reserves, they are largely undeveloped since the discovery of oil and gas in the 1960's. Whilst there are longer-term targets to develop coal-fired power generation, the Governments short-term priority is on gas to power.[14] Further, given (a) higher capital costs for coal plant compared to gas[15] and (b) low cost of domestic gas, coal generation is not currently considered a viable option. There have been no grid-connected coal-fired power plants built in recent years in Nigeria.	Yes, coal-fired installation would operate as base-load plant	Not plausible

[14] Federal Presidency of Nigeria (2010) *Roadmap for Power Sector Reform*. August 2010. Chapter 3.

[15] Coal-fired steam cycle power generation- $$2,200 per kW; gas-fired combined cycle - $1,100 per kWe (IEA/OECD estimates of typical investment costs in 2010). See www.etsap.org/E-techDS/EB/EB_E02_Gas_fired%20power_gs-gct.pdf and www.etsap.org/E.../EB_E01_Coal_fired_power_FINAL_revGS161109.pdf

Scenario description	Compliance with applicable legal and regulatory requirements?	Realistic and credible?	Outputs comparable to the CDM project activity?	Conclusion on plausibility as baseline scenario
***Option 4:** Power generation using oil (e.g. diesel/HFO)*				
Oil-fired power generation using conventional steam cycle Efficiency: 38-44% Lifetime: 20-30 years	Yes	No, oil-fired generation has not been common practice for large-scale power plants in the region (or worldwide) over the past two decades. Insufficient Nigerian oil refining capacity[16] means that refined products (e.g. diesel/HFO) would need to be imported at much higher cost compared to alternative domestic fuel(s) including natural gas. Between 2009 and 2011, diesel prices have varied between N90-150 per litre (see below for more detail on cost comparison).[17]	Yes, due to the grid capacity deficit, oil-fired power generation would operate as base-load plant in Nigeria, if the fuel was available.	Not plausible
***Option 5:** Power generation using hydropower*				
Large-scale hydropower plant (or cluster of smaller units) Lifetime: >50 years	Yes	No, the higher capital costs and lead times would not represent an economically viable project in the absence of CDM. Hydropower resources are not available in the region, where the topography is flat (Nigeria's hydropower plants are located in the Northeast).[18] Would require significant transmission additions with long lead times. Longer term target for Government of Nigeria.[19]	No, would not deliver outputs comparable to the project activity (i.e. base-load power generation) due to power intermittency and low load factor. Seasonal nature of rainfall in Nigeria limits development of hydropower.	Not plausible

[16] Nigeria has four large refineries with a combined nameplate capacity of around 450 000 bbl/d. However, none has ever operated at full capacity, and suffer from theft, vandalism, and fire, resulting in low capacity operation. This means the country imports nearly all of its refined products including those required for oil-fired power; See http://www.oilgasarticles.com/articles/88/1/Downstream-Oil-and-Gas-and-Refining-in-Nigeria/Page1.html and US DOE EIA: Nigeria Country Brief; http://www.eia.gov/EMEU/cabs/Nigeria/pdf.pdf). See also: http://allafrica.com/stories/201108081342.html) and http://allafrica.com/stories/201102110404.html

[17] See: http://www.businessdayonline.com/NG/index.php/news/76-hot-topic/18992-companies-profits-jobs-in-danger-as-diesel-price-hits-roof-

[18] See: Report of the Vision 2020 National Technical Working Group on Energy Sector. July, 2009. Locations of hydro resources are shown in Section 2.4.2.

[19] Federal Presidency of Nigeria (2010) *Roadmap for Power Sector Reform*. August 2010. Chapter 3 and 4.

Scenario description	Compliance with applicable legal and regulatory requirements?	Realistic and credible?	Outputs comparable to the CDM project activity?	Conclusion on plausibility as baseline scenario
Option 6: *Power generation using wind*				
Large-scale array of grid-connected wind turbines Lifetime: 15-20 years	Yes	No, the higher capital costs and lead times would not represent an economically viable project without CDM or similar support. Sufficient wind resources are not available in the region, and limited consideration of the potential of wind power to date; the most ambition scenario suggests only 1% of national electricity supply from wind by 2020.[20]	No, would not deliver outputs comparable to the project activity (i.e. base-load power generation) due to power intermittency and low load factor	Not plausible
Option 7: *Power generation using other renewable sources*				
Biomass; solar; tidal; wave Lifetime: 20 years	Yes	No, higher capital costs and unproven regional demonstration of plants preclude economic viability without CDM or similar support. Most ambition target for biomass is 1000 MW of installed capacity by 2020.[21]	No, would not deliver outputs comparable to the project activity (i.e. base-load power generation) due to power intermittency and low load factor. Reliable biomass fuel supply chains are not developed in region.	Not plausible
Option 8: *Power generation using nuclear*				
Nuclear power generation Efficiency: 30% Lifetime: 40 years	National policy does not currently permit private sector investment in nuclear power	No, there are no existing nuclear power plants in Nigeria and the national nuclear policy in Nigeria is unresolved. The only nuclear plant in Africa is in South Africa. Ambitious goal of installing 1500 MW by 2015[22] seems unlikely to be fulfilled because safety concerns likely to override such ambitions (Nigeria struggles to maintain gas-fired power plant fleet).	Yes, nuclear power generation would operate as base load plant	Not plausible

[20] See for example, limited consideration of wind in Report of the Vision 2020 National Technical Working Group on Energy Sector (page 108) and *Roadmap for Power Sector Reform op cit.*

[21] See: Report of the Vision 2020 National Technical Working Group on Energy Sector (page 111).

[22] See: Report of the Vision 2020 National Technical Working Group on Energy Sector (page 105).

Scenario description	Compliance with applicable legal and regulatory requirements?	Realistic and credible?	Outputs comparable to the CDM project activity?	Conclusion on plausibility as baseline scenario
Option 9: *Import of electricity from connected grids, including new interconnections*				
Import of electricity from other regions/countries	Unknown; Nigeria does not import electricity	No. Nigeria has only one interconnector, a 132kV link with Niger built in 1976. This link is located in the northeast of Nigeria, over 1,000 km from the project and has a maximum capacity of 40MW. [23] Even if the import capacity was higher, the Nigerian grid is insufficient to transmit the required power to the River State region The 132kV link has allowed hydroelectricity to be exported from Nigeria to Niger over the past decade; Nigeria has never imported power via this link [24] as Niger is unable to export sufficient power to the Nigerian grid. [25]	No, the interconnector and Nigerian grid system are unable to provide base load power equivalent to the project (limited to 40 MW)	Not plausible

Note on use of off-grid diesel power generation

In addition to the (on-grid) options considered above, the use of off-grid diesel power generation could be considered as a plausible baseline scenario for meeting Nigerian electricity demand. The current practice to cope with the deficit of available capacity on the Nigerian grid (and intermittent supply from available grid capacity) is for industrial, commercial and residential customers with sufficient capital to invest in off-grid diesel-fired reciprocating engines. There is estimated to be some 3.6 GW of non-residential diesel generation capacity and 900 MW of residential diesel (see Figure 6 below). The electricity generated by these units is expensive: the fuel cost alone makes the electricity considerably more expensive than grid electricity (when available).[26] The up-front capital cost of these units limits their use to businesses and higher income households. In the context of Nigerian

[23] See: World Bank Report No. 32149 on Niger Energy Project (15 April 2005) : http://lnweb90.worldbank.org/oed/oeddoclib.nsf/DocUNIDViewForJavaSearch/940A328EB0D35B5F85257070007F3EC3/$file/ppar_32149.pdf

[24] See http://www.indexmundi.com/g/g.aspx?c=ni&v=83

[25] See: World Bank Report No. 32149 on Niger Energy Project (15 April 2005); link provided above

[26] Diesel prices in Nigeria varied between N90-150 per litre between 2009-2011 (see footnote 17). This translates to between US$ 18-30 per MMBtu for diesel (assuming 34,000 Btu per litre). Gas prices for the Afam power plant are around US$ 0.37 per MMBtu (see Table 5, US$ [redacted] MWh = US$ [redacted] MMBtu). On this basis, the capital and operating costs for diesel generation fired generation would need to be around 60-times cheaper to make it more economically attractive than gas. Further, these assumptions do not include the difference in thermal conversion efficiencies between the two technologies, which is around 35% for well maintained diesel generators compared to 50% for CCGT.

power supply and grid infrastructure constraints, development of new grid-connected capacity would displace power generation from these units.

A modification to the “Tool to calculate emission factor for an electricity system” was approved at EB50 to include provision for displacement of off-grid generation. This is applied to this PDD by showing that the emission reductions that would arise from the displacement of off-grid diesel generation are considerably higher than the emission reductions from the selected OCGT baseline. The thermal efficiency levels are similar, but the CO2 emission factor for diesel is higher than for natural gas.[27]

Based on the above analysis, the following options are identified as plausible baseline scenarios:

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

Further analysis of the economic attractiveness of these two plausible baseline scenarios’ is presented below, in order to identify the most economically attractive baseline scenario alternative.

Step 2: Identify the economically most attractive baseline scenario alternative

The most economically attractive baseline scenario alternative was identified using standard investment analysis in current US$ to calculate the project Internal Rate of Return (IRR) for both baseline options. Project IRR is an established financial indicator used by banks, financial institutions and project developers when assessing project investment choices. Note that the analysis does not account for the salvage value and working capital returned. This is due to two reasons. Firstly, according to SPDC it is very difficult to put a value on the working capital returned and it would very likely be negligible. Secondly, a sensitivity analysis for a range of salvage values indicated that the IRR is hardly affected. For example, varying the salvage value between 0% and 20% of present capital expenditure resulted in variations in IRR of maximum 0.2%. Table 5 summarizes the key assumptions and outputs (project IRR) for the two scenarios identified as plausible alternatives to the project activity (Option 1 and Option 2) as applicable at the time of investment decision-making for the project activity (2005).

Note that in Nigeria, following the introduction of the Multi-year Tariff Order (MYTO) by the Government in 2008 to help overcome revenue losses and ensure cost recovery in the power sector, electricity tariffs and fuel prices are determined (e.g. they are set) under contractual Power Purchase Agreements (PPA) signed between the regulator and power plant operators. Annex A to the Afam PPA (“Tariff, Indexation and Adjustment”) determines that natural gas prices paid by the plant operator are expressed in terms of dollars per MWh (i.e. payment based upon fuel energy content). Electricity revenues comprise two components; a capacity payment (expressed in dollars per MW per hour) and a commodity payment e.g. the power supplied to the grid (expressed in dollars per MWh).

Note also that the Afam PPA is dated December 2005 and has a term of 20 years. The investment analysis undertaken as part of this PDD assumes a 20 year financial period from the start of normal operations (e.g. supply of electricity from Afam VI). This in turn means that the current PPA does not fully cover the entire expected operational period of the power plant. However, a full 20 year period has been chosen for several reasons. Firstly, the cessation of the PPA would not necessitate the closure of the power plant and/or its financial

[27] A survey undertaken in the PDD accompanying NM0208 found that the weighted average thermal efficiency for new off-grid diesels in Nigeria was 37.4%.

operations; upon termination of the PPA, the required contractual arrangements would be reached - albeit possibly under different financial and political circumstances. Secondly, a large-scale CCGT project (particularly one located in a region where there is a chronic shortage of grid power supply and growing demand) would typically be expected to operate for 20 years or more. Finally, given a degree of uncertainty regarding the operational life of the plant and the future form of any new contractual arrangements, an assumed period of 20 years is deemed conservative; for shorter financial periods (e.g. 15 years), the IRR reached by the project in the absence of CERs would be reduced - thereby also reducing the likelihood that the project without CERs reaches the investment hurdle rate across the variations of parameters, as documented in the sensitivity analysis (see Section B.5 below).

From the summary results provided in Table 5, it can be seen that for ***Option 1:*** *Project activity not implemented as a CDM project*, the project IRR is 15.8% whereas for ***Option 2:*** *Power generation from natural gas using OCGT*, the project IRR is significantly higher at 27.6%. An investor not concerned with the reduction of CO_2 emissions would therefore choose the OCGT option rather than the CCGT option.

These results are based upon a conservative estimate of the relative cost of OCGT compared with CCGT (for both capital and annual costs, which are significantly lower for OCGT plant). In reality, the difference in IRR between the OCGT and CCGT plant would likely be significantly greater. The investment analysis clearly indicates that investment in the gas-fired OCGT plant (Option 2) would have been the most economically attractive option at the time of the investment decision and this therefore constitutes the baseline scenario. As stated above, the capital cost assumptions for the OCGT baseline option are conservative: if the International Energy Agency (IEA) value of OCGT costs being 60% of the equivalent CCGT costs[28] were applied, then the IRR for the OCGT option would be 37%. The economics from the relative gas and electricity prices in Nigeria clearly indicate that an OCGT plant constitutes the baseline investment option.

[28] Assumptions underlying the IEA's World Energy Outlook, 2008.

Table 5: Technical and financial factors relevant to the project activity

Assumptions [notes]	**CCGT power plant (Option 1)**		**OCGT power plant (Option 2)**	
Capacity	Values	*Units*	Values	*Units*
GT capacity	450	*MW*	650	*MW*
ST capacity	200	*MW*	-	*MW*
Total installed capacity [1]	650	*MW*	650	*MW*
Plant lifetime	20	*years*	20	*Years*
Investment costs				
Total plant investment cost [2]	423.8	*$ million*	296.66	*$ million*
(cost per kW installed)	652	*$/kW*	456	*$/kW*
Fuel costs				
Net plant thermal efficiency [3]	50	*%*	36	*%*
Plant load factor (assumes base load)	90	*%*	90	*%*
Plant availability factor [4]	95	*%*	95	*%*
Net power generation	5 124 600	*MWh*	5 124 600	*MWh*
Fuel requirement	10 249 200	*MWh*	14 235 000	*MWh*
Fuel requirement (1MWh = 3.6 GJ)	36 897 120	*GJ*	51 246 000	*GJ*
Fuel requirement (NCV = 35 MJ/m^3)	1 054 203	*000 m^3*	1 464 171	*000 m^3*
Fuel cost [5]	[redacted]	*$/MWh*	[redacted]	*$/MWh*
Annual fuel cost	[redacted]	*$ million*	[redacted]	*$ million*
Operating costs				
Annual O&M costs [6]	30.2	*$ million*	21.2	*$ million*
Revenues				
Power capacity payment [5]	[redacted]	*$/MW per hour*	[redacted]	*$/MW per hour*
Power commodity payment [5]	[redacted]	*$/MWh*	[redacted]	*$/MWh*
(effective equivalent wholesale power tariff)	[redacted]	*$/MWh*	[redacted]	*$/MWh*
Annual electricity revenues	[redacted]	*$ million*	[redacted]	*$ million*
Financial performance				
Project IRR (over 20 years)	15.8	*%*	27.6	*%*

See workbook "Afam PDD cash flow v25_NOTES ADDED" for how these have been applied to demonstrate and assess additionality

Notes:

[1] This is the capacity contractually committed, based on a conservative estimate of the performance of the units in local ambient air temperature conditions and is therefore slightly lower than the units' name plate rating.

[2] Total cost to completion for CCGT plant calculated at time of investment decision, based on detailed itemised payments for plant costs provided by equipment suppliers (Daewoo); see EPC contract signed 9 December 2005. The capital cost for an equivalent OCGT plant has been estimated by applying a conservative multiplier of 0.7 to the CCGT capex figure; this is consistent with assumptions made in the IEA World Energy Outlook 2005, Middle East and North Africa Insights (where 2005 investment costs are given as $350/kWe for OCGT and $500/kWe for CCGT). The fact that this estimate is conservative can be seen, for example, from the fact that the IEA assumes (for the World Energy Outlook 2008) that OCGT costs are 60% of CCGT costs. Using this value would result in a baseline IRR value of 37% for the OCGT option.

[3] The CCGT efficiency figure represents the assumption used by SPDC throughout the process of project evaluation

[4] Assumption used in the Nigerian Electricity Regulatory Commission (NERC) Multi-year Tariff Order (MYTO) 1st July 2008 to 30th June 2012. Order No: NERC/GL059. Note that the MYTO was introduced by the Government of Nigeria to overcome annual revenue losses in power generation, based on the principle of operational cost recovery, return on investment for new capital investment and replacement capital investment. The MYTO sets tariffs and prices, which are in turn reflected in the Power Purchase Agreements (PPA) for individual power plants.

[5] As set in the Afam Power Purchase Agreement (PPA); Annex A to the PPA ("Tariffs, Indexation and Adjustment") determines that gas prices (i.e. fuel cost) are expressed in dollars per MWh, power capacity

payments are expressed in dollars per MW per hour and power commodity payments are expressed in dollars per MWh.
[6] The value for the CCGT plant (project) represents the conservative annual value of the Long Term Service Agreement (LTSA) scheduled and unscheduled maintenance provided by the lowest contract bidder at the time of final investment decision (FID), whose NPV at the time of the investment decision was calculated by SPDC to be $161.02m for a contract period of 15 years. The O&M value represents the present value discounted at a rate of 17% (as with the capital costs). The value for the OCGT plant is based on the same ratio as the capital costs, consistent with the IEA World Energy Outlook sources referred to above, where O&M is assumed to be the same percent of Capex for OCGT and CCGT. This is consistent with the expectation that O&M costs for the much simpler OCGT plant would be expected to be lower than for the CCGT plant. The magnitude of the O&M cost is at the higher end of the expected range internationally (see, for example, IEA, Projected Costs of Generating Electricity, 2005 and 2010 editions).

As required by the methodology, a sensitivity analysis was performed in order to confirm this conclusion. The sensitivity analysis of the project financial performance was performed by subjecting both baseline scenarios (Option 1 and Option 2) to potential variation in the following critical parameters:

- Investment cost
- O&M costs
- Natural gas price
- Electricity price

The financial performance was calculated for a 10% deviation for each parameter, reflecting potential variations for these factors within the project crediting period. The results of the sensitivity analysis are presented in Table 6 below (values shown are project IRR):

Table 6: Sensitivity analysis on baseline and project IRR

	Option 1	*Option 2*	*Option 1*	*Option 2*
Sensitivity 1: Investment cost	**10% increase**		**10% decrease**	
	13.8%	21. 5%	18.2%	36.7%
Sensitivity 2: O&M costs	**10% increase**		**10% decrease**	
	14.7%	25.2%	16.9%	29.9%
Sensitivity 3: Natural gas price	**10% increase**		**10% decrease**	
	15.3%	26.6%	16.2%	28.7%
Sensitivity 4: Electricity price	**10% increase**		**10% decrease**	
	19.5%	33.7%	12.1%	22.0%

The sensitivity analysis confirms the result obtained in the investment analysis. ***Option 1: Project activity not implemented as a CDM project*** has the lowest economic performance among the alternatives and remains so in circumstances subjected to potential variations in the critical cost parameters. Therefore, it is concluded that ***Option 2: Power generation from natural gas using OCGT*** represents the most economically attractive baseline scenario across a range of input variables.

The choice of OCGT technology as baseline scenario is confirmed with the calculation of the baseline emission factor. This is done in Section B.6.and follows the methodological tool "Tool to calculate the emission factor for an electricity system" v2.2.1

B.5. Demonstration of additionality

As per the methodology, the project proponent is required to establish that the GHG reductions due to the project activity are additional to those that would have occurred in absence of the project activity. The latest version of ACM0029 (Version 03) requires the following steps to be taken:

- Step 1: Benchmark Investment Analysis
- Step 2: Common Practice Analysis
- Step 3: Impact of CDM Registration

The methodology describes for each above step, which sub-steps of the latest version of the "Tool for the demonstration and assessment of additionality" (Version 06.0.0) must be followed. The application of Step 1 (Benchmark Investment Analysis); Step 2 (Common Practice Analysis); and Step 3 (Impact of CDM Registration) are described 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" to be followed:

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

Apply benchmark investment analysis

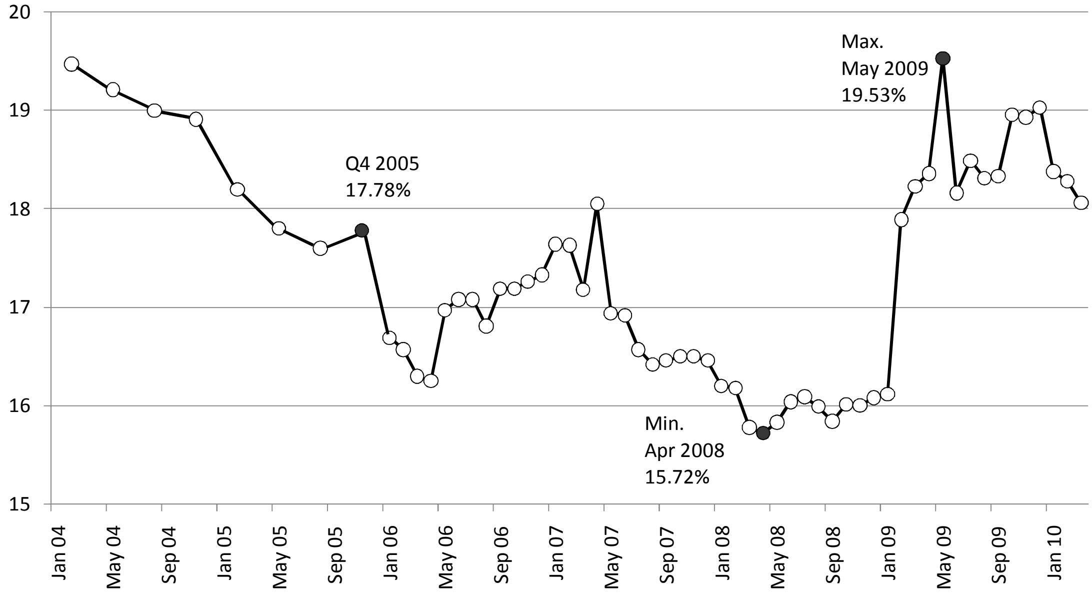
The investment analysis of the project activity has been undertaken using the project Internal Rate of Return (IRR) as the financial indicator. A cost of capital benchmark needs to be selected that is appropriate for the Afam power project. The Afam power plant is financed by the Shell Petroleum Development Company of Nigeria Limited (SPDC) joint venture (JV) partners. SPDC is the operator of a Joint Venture Agreement involving the Nigerian National Petroleum Corporation (NNPC), which holds 55 per cent, Shell 30 per cent, EPNL 10 per cent and Agip 5 per cent. In Nigeria, the expected IRR for a project needs to be considerably higher than it would be in a developed market economy to justify the country risk.[29] The commercial structure for the project cannot be described in classic project financing terms, nor can it be categorised in simple corporate financing terms, due to the multi-party JV.

Since a generic project finance weighted average cost of capital (WACC) adjusted for Nigeria country risk is not suitable, and a corporate WACC is similarly inappropriate, the rate on Nigerian commercial bank debt has been chosen as being the most appropriate alternative benchmark. This is considered to provide a conservative (low) benchmark for the opportunity cost of capital in Nigeria.

Figure 5 shows the official prime lending rate, as published by the Central Bank of Nigeria. It shows that at the project start date (9 December 2005), the lending rate was 17.78% (Q4 2005 data). Since then, the prime lending rate has varied between a low of 15.72% and a high of 19.53%.

[29] For one simple example of what country risk can mean, the Afam project site was the subject of a militant attack, which resulted in unexpected additional costs to the project from damage and security-related measures of US$50 million.

Figure 5: Nigerian prime lending rate (2004-2010)



Source: plot of data from the Central Bank of Nigeria. See http://www.cenbank.org/rates/mnymktind.asp; http://www.cenbank.org/OUT/PUBLICATIONS/STATBULLETIN/RD/2005/2004%20STAT-BULL-PART%20A.PDF; http://www.cenbank.org/OUT/PUBLICATIONS/REPORTS/RD/2007/STABULL-2005.PDF

On this basis, for the purposes of the benchmark analysis, an **IRR below 17%** has been considered insufficient to justify the country risk for large capital investments such as the Afam power project.

Calculation and comparison of financial indicators

Comparison of financial indicators are shown in the Excel workbook "Afam PDD cash flow v25_NOTES ADDED", which all suggest that the OCGT is the most economically attractive option, and the project activity is only an attractive investment option i.e. exceeds the IRR hurdle rate if the revenues from CERs is taken into account (the project IRR of the project activity without CDM revenues has been calculated as outlined in Step 3 "Impact of CDM registration" below).

Sensitivity analysis

As with the sensitivity analysis undertaken under Step 2 of section B.4 (i.e. 'Identification of the economically most attractive baseline scenario alternative'), the following parameters were considered critical to the economic performance of the project activity:

- Investment cost
- O&M costs
- Natural gas price
- Electricity price

The financial performance was calculated for a 10% deviation for each parameter for the project activity undertaken without CDM revenues, reflecting potential variations for these factors within the project crediting period as required by the guidance accompanying the latest version of the tool for additionality. The results of the sensitivity analysis are presented in Table 7 below (values shown are project IRR).

Table 7: Sensitivity analysis on project IRR without CERs

Sensitivity 1: Investment cost	**10% increase**	**Base investment cost**	**10% decrease**
	13.8%	15.8%	18.2%
Sensitivity 2: O&M costs	**10% increase**	**Base O&M cost**	**10% decrease**
	14.7%	15.8%	**16.9%**
Sensitivity 3: Natural gas price	**10% increase**	**Base natural gas price**	**10% decrease**
	15.3%	15.8%	16.2%
Sensitivity 4: Electricity price	**10% increase**	**Base electricity price**	**10% decrease**
	19.5%	15.8%	12.1%

The results of the sensitivity analysis confirm that the IRR of the project activity without CDM revenues is lower than the benchmark for the project activity required by investors for comparable project activities in Nigeria, under circumstances which could bring about reasonable variations in the parameters used in the IRR calculations. However, two exceptions are noted and require explanation. If the electricity tariff received by the project is increased by 10%, the project is seen to pass the benchmark IRR hurdle rate. However, this condition is considered to be unlikely given the political sensitivity of electricity price increases, the history of low power prices in Nigeria and difficulties with electricity bill collection in Nigeria and the Rivers state region. More importantly, the tariffs are defined in the Afam project Power Purchase Agreement (PPA), which sets the tariff price for electricity for 20 years. Similarly, if the investment cost were to decrease by 10% the project is seen to pass the benchmark IRR hurdle rate. This sensitivity is theoretical, and not practical since the value used in the baseline calculation is based on the actual contracted total investment cost for the project (quoted by Daewoo to SPDC at the time of FID) not including contingencies and unforeseen payments[30]. Therefore, any deviations from the base investment cost value would in reality be upward, not downward.

The values for each of the variable parameters at which the benchmark IRR hurdle rate (17%) is passed were also calculated. In order to reach the benchmark, one or more of the following conditions would need to be satisfied:

- The **investment cost** would need to decrease significantly from $423.8m to $398.5m
- The O&M costs would need to decrease significantly from $30.2m per year to $26.9m
- The **natural gas price** would need to decrease significantly from $1.26/MWh to $0.89/MWh
- The **electricity price** would need to increase from $18.70/MW/h (capacity payment) and $0.50/MWh (commodity) to $19.39/MW/h (capacity payment) and $0.52/MWh (commodity)

For the reasons outlined above, the likelihood of one or more of these conditions arising, and being considered feasible at the time of the investment decision, is negligible. Note that the natural gas price values used in the analysis are also real values as contained, and therefore contractually set, in the Afam project PPA. Furthermore, note that the O&M costs would almost certainly be higher than the conservative value chosen for the purposes of the

[30] The total plant investment costs (excluding the costs associated with raids in 2007) total $564.4m as of August 2011, which is significantly above the anticipated project investment cost at the time of Final Investment Decision.

calculation; a significantly higher cost bid was chosen by the project sponsor than the value used here (which is based on the lowest cost bid provided). In addition, the costs quoted by the bidder(s) are the subject of a contractual service agreement rather than estimates provided by the project sponsor. The possibility of the chosen O&M cost value decreasing by such a significant level is therefore considered to be unfeasible.

The above analysis therefore confirms that the project activity without CDM revenues is financially unviable across a range of realistic variations in the critical parameters determining project IRR and that therefore hence CDM revenues are required to implement the project activity.

Step 2: Common Practice Analysis

The methodology requires the following sub-steps contained within the latest version of the "Tool for the demonstration and assessment of additionality" to be followed according to 'common practice analysis':

- Sub-step 4a: Analyze other activities similar to the proposed project activity
- Sub-step 4b: Discuss any similar Options that are occurring

The common practise analysis requires analysis of the extent to which the proposed project type (e.g. technology or practice) has already diffused in the relevant sector and region.

In line with the "Tool for the demonstration and assessment of additionality v.06.0.0", we have focused on plants that are currently operational, of similar scale (325 MW to 975 MW) and use similar technology (CCGT). The regional scope considered is Nigeria. We have identified only two thermal power plants in Nigeria of similar size and technology to the proposed project[31]. Table 8 below provides an overview of these plants. All other CCGT power plants located in Nigeria are either not completed yet - and therefore not operational (e.g. Obita, Omoku, Egbema and Alaoji CCGT plants), have considerably larger capacity than Afam IV (e.g. Sapele plant with 1050MW) or are too small for comparison - and have been constructed long before Afam or indeed the CDM existed (e.g. Kolo Creek built in 1983 with capacity of 40MW).

Table 8: Similar activities considered for best practice

Name of plant	Operator	Capacity	Start of operation	CDM status
Okpai CCGT power plant	Nigeria Agip Oil Company	480 MW	2005	Yes - through flare reduction
Geregu CCGT Power Plant	Power Holding Company Nigeria	414 MW[32]	2007	No

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

Nigeria Agip Oil Company (NAOC) has recently built a 480 MW grid-connected CCGT power plant at Okpai. This project is also located in the Rivers State region of Nigeria (i.e. the same

[31] Projects were identified from the following sources http://www.industcards.com/cc-nigeria.htm, which is based on *Platts UDI World Electric Power Plants Data Base*

[32] http://www.nigeriaelectricityprivatisation.com/wp-content/uploads/downloads/2011/01/Geregu-Genco-2011-01-13.pdf

region as the Afam VI project location), and has been constructed under the same economic and market context i.e. constraints to national power grid. The project capacity size is similarly typical for a modern CCGT plant (450-700 MW). This project is directly using gas produced in association with oil that was previously flared at Kwale Oil and Gas Processing Plant. The project proponent has to date not claimed any emission reduction credits for the downstream displacement of more carbon intensive forms of electricity generation.[33] However, this project has been registered as a CDM project activity (December 2006), claiming CDM credits for the flare abatement component of the project under AM0009. The choice of low emission CCGT technology is therefore considered to be linked to the upstream flare reduction CDM project.

The Geregu power station is located in the State of Kogi and is currently in the process of being privatised. It is still operated by the State-owned Power Holding Company of Nigeria. It was commissioned in 2007 by the then President of Nigeria President Obasanjo. Geregu was the first new greenfield power plant to be funded and commissioned by the President's administration. The project has not been supported by CDM financing and so far no application for CDM status has been undertaken.
A number of other CCGT plants are currently being developed in Nigeria, most notably Egbema, Alaoji and Okitipupa. At the time of writing, these are not operational and face substantial challenges to completion - either due to financing, logistics or security threats - and are therefore not included in the common practice analysis. In accordance with the methodology tool, we therefore do not include them in our analysis.

Discuss any similar Options that are occurring (Sub-step 4b)

The Okpai power plant has been undertaken as a CDM project. However the focus of the CDM credits for the Okpai project was on gas flaring reduction. The Okpai project is the most similar project to the Afam IV project activity due to its geographic proximity, its government independent ownership, size (480 MW) and technology type (CCGT). It provides clear evidence that financial support through CDM credits is required to make these types of projects economically feasible in Nigeria. A number of other projects in Nigeria have obtained CDM financing for gas flaring reduction efforts.

For the Geregu CCGT power plant, no exact details of financing are available. It is only known that the project was financed entirely by federal government funds. This makes this project not directly comparable to the Afam IV project, as the investment decision might not have been made on purely commercial grounds alone but could have been influenced by non economic factors such as social and political considerations.

Undertake quantitative analysis of common practice (para. 47)

As the Afam project is a measure involving the switch of technology without a change of energy source, it is subject to additional quantitative analysis of "common practice" as outlined in paragraph 47 of the "Tool for the demonstration and assessment of additionality v06.0.0". This involves several steps as follows:

Step 1: Plant range, +/- 50% of capacity/output of planned power plant

Drawing on Table 5, the plant relevant range for both capacity (MW) and output (MWh) can be determined as follows (Table 9):

[33] Although the project proponents understand that this was initially considered in the project design, but elected to be removed for final project submission.

Table 9: Plant capacity and output ranges used for common practice analysis

	Capacity (MW)	Output (MWh)
Planned project	650	5,124,600
+50% =	975	7,686,900
-50% =	325	2,562,300
Technology type:	CCGT	CCGT

Step 2 - Number of plants that deliver the same capacity / output in the same geographical area

The next step is to determine which plants in the geographical location of the project activity are comparable in capacity/output as the project activity. For this purpose, the geographical area is assumed to be the Nigerian electricity grid. The relevant year for the assessment is 2005 and before, as the project start date is December 2005. On this basis, N_{all} is determined as follows (Table 10).

Table 10: Power plants data used to determined plants with the same capacity/output in the same geographical area as the proposed project activity

Power plant	Technology type	Installed CAPACITY of Power Plants (MW)	Electricity generation (MWh) in 2005	Year of Commissioning
NESCO *	Hydro	-	-	-
AGGREKO	OCGT	-	-	-
GEOMETRIC **	Diesel	-	-	-
CALABAR	OCGT	-	202	1934
AFAM (I-IV)	OCGT	931.6	1,838,934	1963-2001
DELTA	OCGT	882	3,235,212	1966
KAINJI	Hydro	760	2,586,929	1968
SAPELE	OCGT	1020	878,417	1978
JEBBA	Hydro	578.4	2,268,230	1985
EGBIN	OCGT	1320	8,592,097	1986
SHIRORO	Hydro	600	1,236,090	1989
AES	CCGT	302	2,018,364	2001
OKPAI*	CCGT	450	1,343,611	2005
AJAOKUTA	OCGT	110	80,597	2006
OMOKU	CCGT	100	422,355	2006
OMOTOSHO	OCGT	335	383,266	2007
GEREGU	CCGT	414	378,603	2007
OLORUNSOGO	OCGT	335	103,591	2007
IBOM	OCGT	37	3,204	2009
	N_{all} =	**5**	**2**	

Notes:
N_{all} =

Number of plants in geographical area with CAPACITY >325MW <975MW
Number of plants in geographical area with OUTPUT >2,652,300 MWh <7,686,900 MWh
* Data from NESCO Power Plant is not considered it operates as an isolated system. Okpai excluded as CDM.
All plants constructed after December 2005 are excluded as this is after the proposed start date of the project activity.
Plants marked in red are those that fall within the same capacity / output range as Afam VI (the proposed project activity).

Step 3 - Plants that deliver the same capacity/output but apply different technologies to Afam project activity

The next step is to determine which plants have the same capacity or deliver similar output to Afam VI, the proposed project activity, based on the ranges shown above in Table 9, but employ a different technology. For the purpose of this assessment, OCGT is considered a different technology to CCGT. Based on the technology types and the N_{all} assessment shown in Table 10, this gives an N_{diff} for capacity of 5, and a N_{diff} for output of 2.

Step 4 – F factor calculation

The F factor provides an insight into the share of power plants connected to the grid which employ the same technology as that of the proposed project activity. It provides the key metric for assessing common practice. In the case of the analysis presented in Steps 1-3 above, the following results can be drawn (Table 11).

Table 11: Results of common practice analysis

	CAPACITY	OUTPUT
Factor F (1 - N_{diff} / N_{all}) =	**0.00**	**0.00**
N_{all} - N_{diff} =	**0.00**	**0.00**

The analysis shows that the F factor is < 0.2, and N_{all} - N_{diff} <3. Therefore, the project activity is *not* considered to be "common practice".

Step 3: Impact of CDM Registration

The registration of the project activity will assist in promoting thermally efficient use of natural gas in the Nigerian power sector. Revenues from CDM would help support the continuing operation of the project and employment in the region. It will also help to alleviate issues such as plant staff technical capacity. Moreover, CDM registration will help raise the importance of the project activity's contribution to climate change mitigation and sustainable development, gaining positive recognition among the local community, industry and policy-makers. The project activity is considered to be additional. Because the baseline project (without CDM registration) represents a similar project in terms of fuel type, PPA arrangements and the contribution to the regional grid, potential impacts upon the power sector and electricity market (other than those identified above) have not been considered material.

The IRR of the project activity without CDM revenues has been calculated as 15.8% (see earlier section), which is below the 17% rate adopted as the benchmark for investors in similar projects located in Nigeria. Using the assumptions made at the time of the investment decision, **the project IRR of the project activity with CDM revenues was estimated to be 17.1%** (see Excel workbook “Afam PDD cash flow v25_NOTES ADDED”). This calculation was based upon additional project revenues (compared to the project activity undertaken without CDM) from CERs over a ten year crediting period according to the estimated emission reductions (ER) that could be expected from the project at the time of investment decision-making, namely: emission reductions of 804,972 tCO_2 per year[34] and assuming a CER price of $7.04/$tCO_2$.[35] It was therefore determined that the project activity would only be above the financially attractive benchmark if the project activity attains CDM revenues through sale of the emission reductions.

Since the calculation of the chosen value for $EF_{BL,CO2,y}$ of 0.511 tCO_2/MWh - and subsequent changes requested by the UNFCCC to be made to input parameters in the cash flow calculations (“Afam PDD cash flow v25_NOTES ADDED”), **the project IRR of the project activity with CDM revenues has been estimated to be 16.8%** (see workbook “Afam PDD cash flow v25_NOTES ADDED”). It can be seen that whilst the difference between the project without CERs’ IRR value (15.8%) and the hurdle rate (17%) of 1.2% is still much alleviated, it is not alleviated to the same level as was expected at the time of investment decision-making.

Prior consideration of CDM

Because the starting date of the project activity is before the date of validation, evidence about the management decision considering CDM benefits is necessary. The project participants are requested to provide appropriate evidence for the serious consideration of the CDM prior to the decision to proceed with the project activity (in accordance with CDM-EB/16) for the following:

a) serious consideration of the CDM in the decision to proceed with the project activity, and
b) the indication that continuing and real actions were taken to secure CDM status.

For both a) and b), official documented evidence is provided below.

a) Serious consideration of the CDM in the decision to proceed with the project activity

The official, documented evidence for this is as follows:

- SPDC commissioned a study in 2003 to determine the overall benefits in terms of emissions that the development of the Afam Power Project would bring
- On 4 November 2003, Bent Svensson from the World Bank Secretariat for the Global Gas Flaring Reduction (GGFR) Public-Private Partnership wrote to GGFR participants, including Shell as part of a survey of potential CDM projects in the development pipeline
- On 17 November 2003, Jan Hartog from Shell replied to Bent Svensson, mentioning that the Afam project was under consideration as a CDM project.
- On 26 February 2004, David Mortimer, Governance Manager, Nigeria for Shell International Gas Limited, wrote to his Shell Nigeria colleague Noble Pepple that ‘As you are aware there is considerable interest in G&P [Shell Gas and Power] in supporting initiatives on flaring reduction and the reduction of GHG emissions, with particular interest focussed on Nigeria. Shell has been in dialogue with the World

[34] Originally, off-grid generators combusting diesel were assumed to be the baseline, hence the higher estimate for emission reductions at the time of FID in Q4 2005.

[35] This price is the primary weighted average CER price for 2005 as recorded in *State and Trends of the Carbon Market*, World Bank 2006.

Bank on these issues, and is seeking to promote: … b) demonstration projects that might qualify for carbon credits. It was suggested that Afam might be a suitable candidate for the latter.'

- On the 25 October 2004, a letter was sent from Shell to the World Bank requesting that Afam be considered as a candidate CDM project. The letter notes that although informal discussions had taken place between joint venture partners concerning submission of the project, this was only to be considered formally at a joint venture board meeting of 29 October 2004. The letter also confirms that FID for the project was expected in 2005.
- By early 2005, Shell/SPDC had formally requested assistance in the preparation of an application for carbon credits under the CDM for the Afam gas-to-power project and the World Bank GGFR Secretariat called for Expressions of Interest.
- On 21 May 2005, a consulting team led by ECA was among the firms that submitted an Expression of Interest to the World Bank (which hosts the GGFR Secretariat).
- On 25 July 2005, the ECA-led team was one of five invited to submit a proposal.
- A PIN was submitted to the Nigerian DNA, who issued the Afam project a Letter of Endorsement (LOE) in August 2008.

b) *Indication that continuing and real actions were taken to secure CDM status.*

- The ECA team was awarded the contract by the GGFR, which formally commenced on 9 December 2005.
- From the outset of the study, Shell/SPDC made it clear that the decision to build a CCGT plant only made sense in light of emission reduction considerations, due to the economics of gas and electricity in Nigeria. (As confirmed in the additionality analysis in this document).
- During the course of the work, it became clear that the majority of the emission reduction benefits would arise from the decision to build a CCGT instead of an OCGT power plant. It also became clear that *additional* benefits would arise from the displacement of customers' own generation (which is universally from small and medium-sized diesel engines in Nigeria).
- ECA advised that the methodology for quantifying the emission reductions from displacing numerous, inefficient, high emission small generation engines would be very challenging, compared with the much more straight-forward baseline based on the open cycle alternative. Nevertheless, considering the size of the capacity deficit in Nigeria (and other African and developing countries), the proximate availability of natural gas, the high emissions that arise from this sub-optimal use of resources, and the significant economic burden on the Nigerian economy from high cost diesel generation and constrained electricity access for the poor, Shell/SPDC was keen to make a contribution to the state of the art with a ground-breaking CDM Methodology.
- The GGFR-supported work concluded in December 2006, with advice on a new methodology for displacement of self generation in capacity-deficit systems by low emission grid-connected plants
- The Nigerian DNA issued the Afam project a Letter of Approval (LOA) in January 2007, based on the request from SPDC made in January 2006.
- ECA was contracted by SPDC on 19 January 2007 in a follow-on assignment to prepare this as a new methodology together with a draft PDD for formal submission to the CDM EB.
- The proposed new methodology passed internal review by SPDC on 29 January 2007.
- Validation review by the DOE was completed on 2 February 2007.
- On 5 February 2007, receipt of the NM and PDD was confirmed by the Meth Panel secretariat
- On 19 March to 10 April 2007 the call for public input was open

- The Meth Panel internal desk review was completed on 12 April 2007
- SPDC responded to public comments on 4 May 2007
- The NM and PDD were considered at MP27 31 May to 1 June 2007
- On 5 Jun 2007, the proposed new methodology was posted online as NM0208
- On 30 June 2007, SPDC submitted its response to the Meth Panel comments as version 1.1
- At MP29 from 24 to 28 September 2007, NM0208 was reported as Work-in-Progress
- At MP 30 from 12 to 16 November 2007, NM0208 was not reported on
- At MP31 from 4 to 8 February 2008, NM0208 was reported on as Work-in-Progress
- At MP32 from 7 to 11 April 2008, NM0208 was reported on as Work-in-Progress
- At MP33 from 23 to 27 June 2008, NM0208 was not accepted (graded C)
  'The Panel, in its discussion on the cases NM0208 and NM0246, acknowledges that the reality in many non-Annex I countries (particularly in Africa) is that grid electricity is often insufficient to meet electricity demand, and consumers use off-grid electricity in significant quantities to meet such unmet demand. The Panel requests the Board to take note that further work on this issue will be undertaken to develop methodological approaches to determine the conditions where construction of a grid-connected power plant can be deemed to partly or fully displace off-grid electricity, and to determine an emission factor in such cases.'
- On this basis, Shell/SPDC instructed ECA to proceed with a new PDD based on AM0029, using the simpler baseline of the open cycle plant investment alternative.
- At EB50 16 October 2009, 'The Board considered a revision to the "Tool to calculate the emission factor for an electricity system" in order to incorporate methodological approaches to estimate emission reductions for project activities that affect the operation of off-grid generation capacity. The Board agreed to approve the revision and further requested the Meth Panel to evaluate, based on feedback on its application in the projects, whether there is a need to enhance the usability and attractiveness of the tool for the project proponents.' The revised tool was provided in annex 14 to the EB50 report.
- A modification to the "Tool to calculate the emission factor for an electricity system" in version 2 incorporates much of the thinking originally developed in NM0208. However, it was decided to stay with the decision had already been taken to develop a new PDD based on AM0029, which is the present document.
- Since July 2010, the project has been undergoing validation by DNV, with significant delays and hold ups, including one completeness check failure. This revised PDD addresses the incompleteness checks raised by the UNFCCC Secretariat. The PDD was made available for public comments over the period 16 July 2010 to 14 August 2010.

B.6. Emission reductions

B.6.1. Explanation of methodological choices

The project activity adopts the procedures outlined in the approved methodology (AM0029) to calculate project emissions, baseline emissions, leakage emissions and emission reductions. Most of the analysis is based on the methodological tool "Tool to calculate the emission factor for an electricity system" v2.2.1.

The procedures used for calculating these emissions are described below:

Project emissions:

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

$$PE_y = \sum FC_{f,y} * COEF_{f,y}$$
(1)

Where:

$FC_{f,y}$ = 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
$COEF_{f,y}$ = the CO_2 emission coefficient (tCO_2/m^3 or similar) in year(s) for each fuel and is
obtained as:

$$COEF_{f,y} = \square\ NCV_{f,y} * EF_{CO2f,y} * OXID_f \quad \textbf{(1a)}$$

Where:

$NCV_{f,y}$ = the net calorific value (energy content) per volume unit of natural gas in year y (GJ/m^3) as determined from the fuel supplier, wherever possible, otherwise from local or national data
$EF_{CO2,f,y}$ = the CO_2 emission factor per unit of energy of natural gas in year y (tCO_2/GJ) as determined from the fuel supplier, wherever possible, otherwise from local or national data
$OXID_f$ = the oxidation factor of natural gas (as per the 2006 IPCC Guidelines for National Greenhouse Gas Inventories)

Baseline emissions:
AM0029 requires that 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:

$$BE_y = EG_{PJ,y} . EF_{BL,CO2,y} \quad \textbf{(2)}$$

The methodology requires project participants to use for $EF_{BL,CO2,y}$ the lowest emission factor among the following three options:

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

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

Where:

$COEF_{BL}$ = the fuel emission coefficient (tCO_2e/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 analysis presented below for two of the three options – namely the BM and CM – includes both of the following:

- **Grid connected only**, and
- **Grid connected *plus* off grid power generation**

The latter is included as it is relevant in the context of Nigeria, but is not used to determine the baseline emissions when assessing the most conservative approach because the data does not meet the requirements set out in Annex 2 of the "Tool to calculate the emission factor in an electricity system" v2.2.1, as described in greater detail below.

On this basis the approach taken assumes the following:

- That the relevant electricity system is the Nigerian power grid (not including, and including, off grid power plants) – *Step 1* in the "Tool to calculate the emission factor in an electricity system" v2.2.1
- That an analysis of off-grid power generation is also included for illustrative purposes – therefore Option II in *Step 2* of the "Tool to calculate the emission factor in an electricity system" v2.2.1 is followed.

The key reason for including off grid generation in the analysis is its very high significance for the Nigerian power sector, and it therefore makes a useful illustrative example of applying the off-grid methodology. NEPA estimates suggest that off-grid generation constitutes about 50% of installed generation capacity (see next section). The importance of off grid generation and its economic and social costs was most recently acknowledged in the *Roadmap for power sector reform* study undertaken by the Presidential Task Force on Power[36]. The importance of off-grid diesel generation in Nigeria was also most recently highlighted in a World Bank report stating that

> ***Poor service has forced more than 90 percent of industrial customers and significant numbers of residential consumers to install their own power generators, at a high cost to themselves and the Nigerian economy***.[37]

Ignoring off grid generation in this analysis results in inaccurate results by disregarding a considerable proportion (according to some estimates even the majority) of generation capacity in Nigeria. However, the only comprehensive and robust survey data on off grid power generation in Nigeria is the Triple E Consultants report, dated 2003 (*op. cit.*). Due to the delays in developing this project activity under the CDM (see page 30, Prior Consideration of CDM), this data is not of suitable vintage and quality to meet the requirements laid out in Annex 2 of the "Tool to calculate the emission factor of an electricity system" v2.2.1, in particular the following:

- *Vintage*: requirements under Step 3 of the tool, *ex ante* approach to OM requires use of data on off-grid plants from within one of the five most recent calendar years prior to the date of submission of the CDM-PDD for validation. These data are now out of date and a new survey has not been carried out; and

[36] available at http://www.nigeriapowerreform.org/downloads/

[37] World Bank Report 32 164-NG, p28.

- *Quality*: data requirements in relation to Table 1 of Annex 2 are not contained in the Triple E survey results.

Moreover, undertaking a renewed survey of off-grid generators was not considered to be economically feasible for the purpose of this CDM-PDD. This is because in applying AM0029, the most conservative baseline emission factor must be selected to calculate the baseline emissions, and including off-grid diesel generator sets would necessarily result in a *less conservative* baseline than one in which they not included (i.e. in Nigeria, the dominant fuel in grid-connected power is natural gas and hydropower, both of which are less carbon-intensive than diesel fuel, the fuel of choice for off-grid power generation). To illustrate this point, however, we have included the emission factor calculation for both grid connected only and grid connected and off-grid power generation, working with what off grid data is available and using conservative assumptions as appropriate.

For the avoidance of doubt, the following sections of the PDD only take account of grid connected power generation when selecting the most conservative baseline emission factor for use in the project baseline calculation.

The most recent year selected was 2009, based on the date when the PDD was originally submitted for validation (see *Prior Consideration of CDM* for clarification of delays).

Option 1 – The Build Margin

Introduction

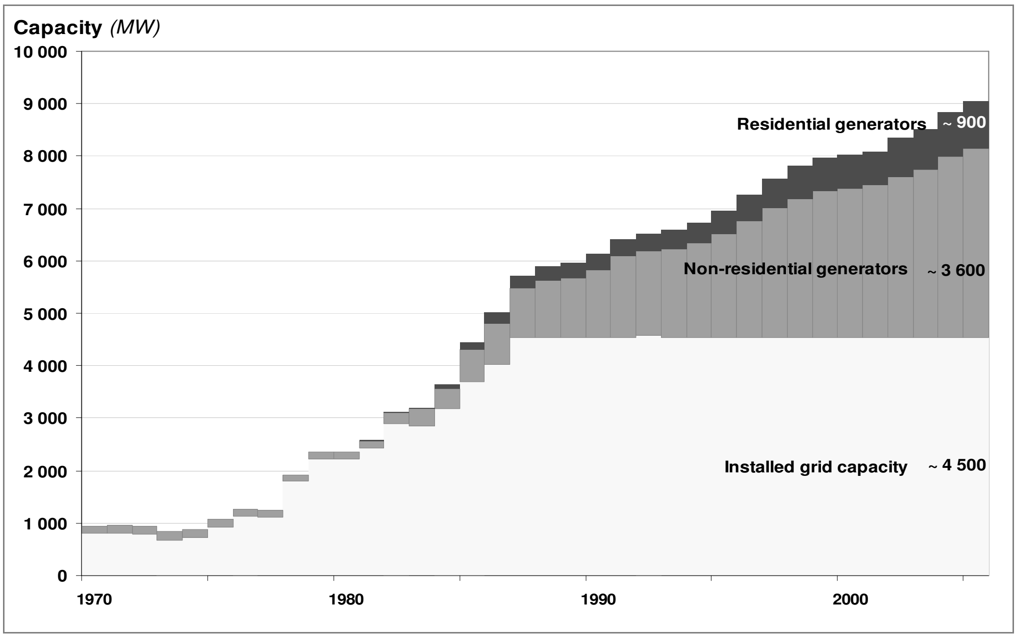
There is a very large generation capacity deficit on the Nigerian electricity grid. This means that there are no ‘marginal plants’ on the grid, as all existing grid-connected plants must operate for all of their available hours to meet demand. To support this assumption, official statistics show that the installed on-grid capacity in Nigeria has not increased since 1987, excluding those covered by CDM project activities such as the Okpai IPP described previously. Officially, there is 4.5 GW of generation capacity supplying the grid. In practice, at any one time much of this capacity is unavailable due to poor maintenance or complete lack of maintenance of generation infrastructure, lack of replacement parts, or breakdown due to incorrect operation. In addition to these problems, the hydro capacity can be affected by seasonal or other shortages of water, reducing the effective available capacity. The combination of the above factors can reduce the available capacity on the grid by one third to one half.

The shortfall in generation capacity in Nigeria is met by off-grid diesel generators used by businesses and households[38]. NEPA collected data from 1974 to 2002 on the capacity (in kVA) of new off-grid generators on residential and non-residential (commercial/industrial) customers’ sites. New capacity installed each year increased from several hundred kVA per year in the mid-1970s to over 500 MVA by 2002. The stock of installed generation capacity has been calculated from the data on new units installed each year by a simple stock model, and the assumptions that each unit has a service life of 15 years with a power factor of 0.85[39]. The two independent sources of NEPA and Triple E indicate that at the end of 2005, there was about 4,500 MW of off-grid generation capacity in Nigeria: 900 MW among residential customers and 3,600 MW supplying commercial and industrial sites. The historical trend of installed capacity since 1970 is shown in Figure 6.

[38] World Bank Report 32 164-NG, p28

[39] i.e. each kVA of capacity generates 0.85 kW of active power

Figure 1: Current and historical on-grid and off-grid generation capacity in Nigeria[40]



The data in Figure 1 also show that the Afam VI plant output (650 MW) is smaller than the capacity deficit (i.e. the difference between the total recorded capacity of around 9 GW and the grid connected capacity of around 4.5GW) and therefore will not have any displacement effect on other power plants connected to the grid. Thus, if power from the Afam plant has the effect of reinforcing the Nigerian power grid, it will likely displace electricity produced by auto-generators who, whilst having a grid connection, elect not to connect to use grid electricity because it is too unreliable. On this basis, it is reasonable to assume that the build margin for power plants in Nigeria is off-grid diesel generators.

Figure 6 further shows that installed capacity of off grid power generation (~ 50% of total capacity) would surpass the critical threshold of 10% required to include off grid generation in the analysis.

Following the methodology set out in Step 6 of the "Tool to calculate the emission factor for an electricity system" v.2.2.1, the build margin is calculated by:

$$EF_{grid,\ BM,\ y} = \left(\sum EG_{m,y} * EF_{EL,m,y} \right) / \sum EG_{m,y} \quad \textbf{(4)}$$

Where,

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

$EG_{m,y}$ = Net quantity of electricity generated an delivered to the grid by all *m* power units in year *y* (MWh)

$EF_{EL,m,y}$ = CO_2 emission factor of all power units with energy source *m* in year 2009 (tCO_2/MWh)

[40] Triple "E". 2005 *Baseline GHG Emission Reduction Estimate for the Proposed Afam Power Rehabilitation Project* Study conducted for Shell Petroleum Development Company of Nigeria, April.

In the approach presented, Option 1 in Step 5 of the "Tool to calculate the emission factor for an electricity system v.2.2.1" i.e. an *ex ante* approach to determining the BM, is taken. The approach presented includes both grid-connected only power plants, and grid connected plus off grid power plants.

Determination of emissions factor for BM using grid-connected and off-grid power plants

The data used in the illustrative calculation is based on option (b) of Step 1 in Annex 2, i.e. *a statistical evaluation of the data based on sampling*. This is mainly due the fact, as highlighted previously, that only very limited data on off-grid production is available and conducting a full survey of generators in the domestic and commercial sectors is not realistically achievable over the available time horizon.

Table 12: Step by step approach for off-grid data collection below provides a summary of the off-grid plant for the data collected in the survey in accordance with Annex 2 of the "Tool to calculate the emission factor for an electricity system v.2.2.1". Most of the data in Table 12: Step by step approach for off-grid data collection is based on one of two sources[41] including a firm survey of 232 firms in Nigeria operating off-grid generation facilities.

Table 12: Step by step approach for off grid data collection

Step		Residential	Non-Residential
1		Statistical evaluation of the data based on sampling	
1.1	*Capacity (MW)*[42]	900 (overall)	3,600 (overall)
	Technology	Reciprocating Engine	Reciprocating Engine
	Fuel	Diesel	Diesel
	Grid	True	True
	Switch	True	True
1.2	*Classification*	Diesel	Diesel
1.3	*Sectors*	Residential	Non-Residential
1.4	*Survey design*	n.a.	n.a.
2	*Exclude plants*	n.a. because based on sample	n.a. because based on sample
3	*Aggregate data*	By using 900MW and 3,600 MW respectively, extrapolation of data on all off grid generation	
4	*Extent of off grid power*	off grid capacity ~ 50% of total capacity (see previous section) and therefore considerably higher than required 10%	
5	*Reliability of grid*	Shortage of generation is key reason for unmet demand and black-outs. This is mainly due to poor maintenance of generation plants rather than transmission and distribution networks.[43]	

In determining the BM including the off-grid power plants, the first step is determine the tranches of plants of different vintage to be included in the BM analysis. Firstly, in order to fill

[41] *The Energy Crisis of Nigeria An Overview and Implications for the Future*, University of Chicago and Public and *Private and Public Electricity Provision as a barrier to Manufacturing Competitiveness*, World Bank

[42] NEPA, Triple E

[43] Federal Presidency of Nigeria (2010) *Roadmap for Power Sector Reform*. August 2010. pg.64

in the gap between 2002 (the year the survey took place) and 2009 (the year selected for baseline determination, the most recent year for which data is available prior to validation), an extrapolation is made based on published estimates of installed capacity (around 6,000 MW in 2009). This provided estimates of installed capacity for off-grid power plants in the various tranches described in Step 1.2 of Annex 2 of the "Tool to calculate the emission factor for an electricity system v.2.2.1" as follows (Table 13).

Table 13: Tranches/vintages of off grid power plants used in the analysis

	MW	MWh*
Plants up to 5 years old	750	224,975
Plants >5 <10 years old	1,400	420,142
Plants >10 years old	3,850	1,154,883
	6,000	**1,800,000**

* In 2009; electricity generation of each off grid tranche has been estimated based on using the default parameters set out in "Tool to calculate the emissions factor of an electricity system v.2.2.1"

These tranches are then included alongside the grid connected power plants in a systems analysis of the BM as follows (Table 14).

Table 14: Grid and off-grid power plants used to determine build margin emission factor ($EF_{BL,CO2}$)

Power plant	Installed Capacity of Power Plants (MW)	Electricity generation (MWh) in 2009	Year of Commissioning
NESCO *	-	-	-
AGGREKO	-	-	-
GEOMETRIC	-	-	-
CALABAR	-	-	1934
AFAM	931.6	151,048	1963-2001
DELTA	882	1,591,573	1966
KAINJI	760	2,505,663	1968
SAPELE	1020	121,269	1978
JEBBA	578.4	2,676,860	1985
EGBIN	1320	3,383,990	1986
SHIRORO	600	2,282,117	1989
AES	302	1,681,451	2001
OFF GRID (>5 <10 YEARS)	1,400	420,142	2000-2004
OKPAI*	450	3,079,384	2005
AJAOKUTA	110	-	2006
OMOKU	100	422,355	2006
OMOTOSHO	335	383,266	2007
GEREGU	414	378,603	2007
OLORUNSOGO	335	103,591	2007
OFF GRID (<5 YEARS)	750	224,975	2005-2009
IBOM	37	3,204	2009

**NOTE: Data from NESCO is excluded as it is on an isolated grid. Okpai power plant is a registered CDM project*

Following the procedure set out in Step 5 of the "Tool to calculate the emission factor for an electricity system" v.2.2.1, and the data presented in Table 14 the BM has been selected based on the sample $\mathbf{SET_{\geq 20\%}}$ as outlined below.

AEG_{total} (MWh)	16,330,107
$AEG_{SET\text{-}5\text{-}units}$ (MWh)	1,093,639
$AEG_{SET\text{-}>\text{-}20\%}$ (MWh)	3,617,587
$AEG_{SET\text{-}>\text{-}20\%}$ / AEG_{total}	22%
$AEG_{SET\text{-}>\text{-}20\%}$ (MWh) > $AEG_{SET\text{-}5\text{-}units}$ (MWh), *therefore*	
SET_{sample} (MWh) = $AEG_{SET\text{-}>\text{-}20\%}$	3,617,587

Using the SET_{SAMPLE} (i.e. $SET_{\geq 20\%}$) the two components in equation (4) are used to calculate the BM_{EF} as outlined below (Table 15). In determining the emission factor for off-grid diesel generation ($EF_{EL,m,y}$) presented in Table 15, the guidance in *Step 4 (a) Option A2* of the "Tool to calculate the emission factor for an electricity system" v2.2.1 is employed using the following inputs:

$EF_{CO2,m,y}$ = 0.0741 tCO_2e/GJ (IPCC default emission factor for diesel oil)

$\eta_{m,y}$ = Default values are employed as provided in Annex I of the "Tool to calculate the emission factor for an electricity system" v2.2.1, based on the following average capacities for different types of off grid power plants:

- 33.0% based on the average capacity of *residential* off-grid power plants in the Lagos area using sample data,[44] derived as 30.4 kW (22,710 kW total capacity / 746 plants)
- 37% based on the average capacity of *commercial* off-grid power plants in the Lagos area using sample data, derived as 121.3 kW (10,067 kW total capacity / 83 plants)
- 42% based on the average capacity of *industrial* off-grid power plants in the Lagos area using sample data, derived as 905.0 kW (325,782 kW total capacity / 360 plants)

The workings used to calculate the average capacity of off-grid power plants in the Lagos area is shown in sheet "off grid 2" in Excel workbook "Afam PDD Baseline EF calculations v2.3_corrected", whilst the derivation of the $EF_{CO2,m,y}$ for the various tranches of off-grid power plants is shown in sheet "off grid 3" in the same workbook.

Note that, in respect of *m* in the chosen methodology, the classes of off grid power generation have been combined into one since the split of residential and non-residential cannot be determined in the absence of more recent survey data.

For the calculation of $EG_{m,y}$ in equation (4) Option 3 in Step 4 of the "Tool to calculate the emission factor for an electricity system" v2.2.1 is applied. Because of the lack of appropriate data, the conservative estimate of 300 hours of off grid operation per year is chosen. Using

[44] Triple "E". 2005 *Baseline GHG Emission Reduction Estimate for the Proposed Afam Power Rehabilitation Project* Study conducted for Shell Petroleum Development Company of Nigeria, April.

these parameters in equation (4) results in a value for the off-grid $EF_{BL,CO2}$ of **0.673 tCO_2/MWh** (see sheet "off grid 3" in Excel workbook "Afam PDD Baseline EF calculations v2.3_corrected", as shown below (Table 15).

Table 15: Determination of BM emissions factor ($EF_{grid, BM y}$) for grid and off-grid power plants

Power plant (*m* power units)	Gas consumed (2009)	Electricity (2009)	Plant type	$EF_{(el,m,y)}$
	MMSCF	MWh	-	tCO_2/MWh
AES	21,946	1,681,451	OCGT	0.73
OFF GRID (>5 <10 YEARS)	NA	420,142	OFF-GRID DIESEL	0.67
AJAOKUTA	NA	0	OCGT	0.51
OMOKU	NA	422,355	CCGT	0.34
OMOTOSHO	4,279	383,266	OCGT	0.62
GEREGU	5,071	378,603	CCGT	0.74
OLORUNSGO	940	103,591	OCGT	0.50
OFF GRID (<5 YEARS)	NA	224,975	OFF-GRID DIESEL	0.67
IBOM	NA	3,204	OCGT	0.51
TOTAL	-	**3,617,587**	-	-

NOTE: Not all grid-connected power plant have gas consumption data available, and therefore default values using the "Tool to calculate the emission factor for an electricity system" v.2.2.1 have been employed. See below.

$\sum EG_{m,y} * EF_{EL,m,y}$ =	2,217,788	
$\sum EG_{m,y}$ =	3,617,587	
$EF_{grid, BM, y}$ =	0.6131	
$EF_{grid, BM y}$ =	**0.613**	tCO_2/MWh

As shown above, the emission factor for grid connected plus off grid power plants results in the a value of $EF_{BL,CO2}$ of **0.613 tCO_2/MWh** (see sheet "INCL OFF GRID Option 1" in workbook "Afam PDD Baseline EF calculations v2.3_corrected")

Determination of emissions factor for BM using grid-connected power plants only

As required by the approach taken, the emissions factor $EF_{BL,CO2}$ for only **grid connected power plants** in Nigeria has also been calculated. This was undertaken using the most recent data available at the time of validation, namely 2009 power generation data. This included information provided the Osogbo National Control Centre (NCC) operated by the Power Holding Company of Nigeria (PHCN)[45], plus additional information on the specific gas consumption at the Okpai IPP, which is owned and operated by Agip Nigeria (IPP data on gas consumption are not provided by NCC Osogbo). These data are shown in Table 14 above, which have been used as the basis for determining $EF_{BL,CO2}$ for grid-connected power plants (i.e. excluding the off grid tranches shown in Table 14). The full description of the steps and data are presented the sheet "GRID ONLY Option 1" in the Excel workbook "Afam PDD Baseline EF calculations v2.3_corrected".

[45] PHCN (2010) Generation and Transmission Grid Operations 2009. National Control Centre Osogbo, Annual Technical Report. Osogbo, Nigeria.

In accordance with the "Tool to calculate the emission factor for an electricity system" v2.2.1, determination of the relevant sample set used to calculate the build margin is applied as follows (Table 16).

Table 16: Determination of BM sample set (using grid connected power plants shown in Table 14**)**

AEG_{total} (MWh)	15,684,990
$AEG_{SET\text{-}5\text{-}units}$ (MWh)	1,291,019
$AEG_{SET\text{->-}20\%}$ (MWh)	5,254,587
$AEG_{SET\text{->-}20\%}$ / AEG_{total}	34%
$AEG_{SET\text{->-}20\%}$ (MWh) > $AEG_{SET\text{-}5\text{-}units}$ (MWh), *therefore*	-
SET_{sample} (MWh) =	5,254,587
SET_{sample} (MWh) excluding units > 10 years old	2,972,470
SET_{sample} (MWh) excluding units > 10 years old / AEG_{total}	19%
SET_{sample} (MWh) excluding units > 10 years old, including 1st CDM project / AEG_{total}	39%
$AEG_{SET\text{-}Sample\text{-}CDM}$ (MWh)	6,051,854
$AEG_{SET\text{-}Sample\text{-}CDM}$ / AEG_{total}	39%

On the basis of the analysis shown above (Table 16), the $SET_{sample\text{-}CDM}$ is derived as follows:

1. $AEG_{SET\geq20\%}$ excluding Okpai (as a CDM project) comprises a larger annual generation than $AEG_{SET\text{-}5\text{-}units}$. Therefore, $SET_{SAMPLE\text{-}CDM}$ = $AEG_{SET\geq20\%;}$

2. $AEG_{SET\geq20\%}$ includes plants older than 10 years old, and therefore Okpai IPP is included. This covers 39% of total generation and therefore $AEG_{SET\geq20\%}$ - Shiroro (older than 10 years) + Okpai = $SET_{sample\text{-}CDM,}$

The $EF_{grid,BM,y}$ for the $SET_{SAMPLE\text{-}CDM}$ is derived as follows (Table 17).

Table 17: Analysis of sample set to determine build margin emission factor of grid-connected power plants ($EF_{grid,\ BM,\ y}$)

Power plant (*m* power units)	**Gas consumed (2009)**	**Electricity (2009)**	**Plant type**	**$EF_{(el,m,y)}$**
	MMSCF	MWh	-	tCO2/MWh
AES	21,946	1,681,451	OCGT	0.73
OKPAI	21,674	3,079,384	CCGT	0.39
AJAOKUTA	NA	0	OCGT	0.51
OMOKU	NA	422,355	CCGT	0.34
OMOTOSHO	4,279	383,266	OCGT	0.62

GEREGU	5,071	378,603	CCGT	0.74
OLORUNSGO	940	103,591	OCGT	0.50
IBOM	NA	3,204	OCGT	0.51
TOTAL	-	**6,051,854**	-	-

NOTE: $EF_{EL,m,y}$ data shown in red text is derived using default efficiency values from Annex I of the "Annex I of the "Tool to calculate the emission factor for an electricity system" v2.2.1. This is because these plant are IPPs, and do not provide gas consumption data to the NCC Osogbo, with the exception of Okpai.

$\sum EG_{m,y} * EF_{EL,m,y}$ =	3,139,460	
$\sum EG_{m,y}$ =	6,051,854	
$EF_{grid, BM, y}$ =	0.5188	
$EF_{grid, BM\ y}$ =	**0.519**	tCO_2/MWh

As outlined above, excluding the off grid power generation form the BM emission factor calculation results in a value of $EF_{BL,CO2}$ of **0.519 tCO_2/MWh. This is the value used for Option 1** (see sheet "GRID ONLY Option 1" in Excel workbook "Afam PDD Baseline EF calculations v2.3_corrected")**.**

The full workings for analysis outlined in Tables 16 and 17 is shown in sheet "GRID ONLY Option 1" and "Power plant data and assumptions" in the Excel workbook "Afam PDD Baseline EF calculations v2.3_corrected".

Option 2 – The Combined Margin

Introduction

The combined margin is calculated from the build margin and the operating margin. Equal weight is applied to the two factors as stipulated by the "Tool to calculate the emission factor for an electricity system" v2.2.1. Since the build margin emission factor (BM_{EF}) has already been calculated in the previous option (Option 1), this section will outline the calculation of the operating margin only. It will therefore describe the applied data and chosen methodology from Steps 3 and 4 of the "Tool to calculate the emission factor for an electricity system" v2.2.1.

The following approach is taken in determining the emission factor for the OM:

1. A *simple OM* analysis is employed - *Step 3* of the "Tool to calculate the emission factor for an electricity system" v2.2.1; This approach is allowable as the only low cost/must run resource applicable to the Nigerian power markets is electricity generated from hydro power sources, and its share of total electricity generation capacity constituted 32%[46] of total grid connected generation over the period 2005-2009; this is below the critical threshold of 50% (see sheet "Power plant data & assumptions" in Excel workbook "Afam PDD Baseline EF calculations v2.3_corrected").

[46] See Excel workbook "Afam PDD Baseline EF calculation v2.3_corrected"; the data sources used therein are the Annual Technical Reports from the NCC Osogbo, PHCN (2006-2010). Total hydro power generation over the period 2005-2009 = 34,746,743 MWh, from a total grid connected generation of 110,495,790 MWh over the period.

1. An *ex ante* option is taken to calculating the emission factor - *Step 3* of the "Tool to calculate the emission factor for an electricity system" v2.2.1;
2. *Option A* (Calculation based on average efficiency and electricity generation of each plant) is adopted – *Step 4 (a) Simple OM* of the "Tool to calculate the emission factor for an electricity system" v2.2.1;
3. A combination of *Option A1* and *Option A2* is employed to determine the CO_2 emission factor for each plant ($EF_{EL,m,y}$). Option A2 is employed for some plants because gas consumption data was not available for all IPPs (only Okpai); this data is not collected routinely by NCC Osogbo – *Step 4* of the "Tool to calculate the emission factor for an electricity system" v2.2.1

Following on from the approach used for the BM, this is undertaken covering both:

- **Grid connected plus off grid power plants** as an *illustrative* method; and
- **Grid connected power plants only.**

For grid connect power plants, data from the PHCN annual reports provided by the Osogbo NCC have been used for the basis of calculating the generation, which – when applying the last 5 years of data available at the time of validation – covers the period 2005-2009. As required in taking an *ex ante* approach to the determination of power plant emissions, three years of power generation data have been used (2007-2009) to determine the weighted average of power generation.

For off-grid power plants, data from the Lagos area survey of off-grid power generation (Triple 'E' Consultants, 2005, op. cit) has been used as the basis for determining the simple OM analysis including both grid-connected plus off-grid power plants.

Application of *Option A* requires the following method to be used to calculate the OM emission factor:

$$EF_{grid,\ OMsimple\ y} = (\sum EG_{m,y} * EF_{EL,m,y}) / \sum EG_{m,y} \qquad \textbf{(5)}$$

Where,

$EF_{grid,\ OMsimple\ y}$	= Simple OM CO_2 emission factor based on 3-year weighted average using *ex ante* determination option, years 2007, 2008 and 2009 (tCO_2/MWh)
$EG_{m,y}$	= Net quantity of electricity generated and delivered to the grid by all power units with energy source *m* in *y* (MWh)
$EF_{EL,m,y}$	= CO_2 emission factor of all power units with energy source *m* in y (tCO_2/MWh)
m	= all energy sources serving the grid except the must run hydro plants.

$EF_{EL,m,y}$ is calculated by applying a combination of *Option A1 (for PHCN plants for which fuel consumption data is available)* and *Option A2 (for IPP plants which do not publish fuel consumption data);* see sheet "GRID ONLY Option 2" in Excel workbook "Afam PDD Baseline EF calculations v2.3_corrected";

Determination of emissions factor for OM using grid-connected and off-grid power plants

On the basis described above, and using *Option A1* and *Option A2* under Step 4 of the "Tool to calculate the emission factor for an electricity system" v2.2.1 the plant and data used in applying the methodology are as follows (Table 18).

Table 18: Calculation of Operating Margin Emission Factor 2007-2009 (grid and off-grid)

Plant name	Plant emissions (tCO2) ($FC_{i,m,y}$ * $NCV_{i,y}$ * $EF_{CO2,i,y}$)				Elec generation (MWh)	Emission factor (tCO2/MWh)	$EG_{m,y}$ * $EF_{EL,m,y}$
	2007	2008	2009	3-year average	$EG_{m,y}$	$EF_{EL,m,y}$	
KAINJI	-	-	-	-	-	-	-
JEBBA	-	-	-	-	-	-	-
SHIRORO	-	-	-	-	-	-	-
NESCO *	-	-	-	-	-	-	-
OFF GRID (>10 YRS)	-	-	-	-	1,154,883	0.673	776,983
EGBIN	1,978,264	2,660,261	1,308,084	1,982,203	3,800,745	0.522	1,982,203
SAPELE	411,060	426,503	77,952	305,172	447,012	0.683	305,172
AFAM	996,570	263,891	126,427	462,296	579,141	0.798	462,296
DELTA	2,123,570	1,170,127	1,218,492	1,504,063	1,933,093	0.778	1,504,063
AES	1,150,728	1,329,177	1,219,489	1,233,131	1,734,550	0.711	1,233,131
OFF GRID (>5 <10 YRS)					420,142	0.673	282,663
CALABAR	-	-	-	-	-	-	-
AGGREKO	-	-	-	-	-	-	-
GEO-METRIC	-	-	-	-	-	-	-
OKPAI	1,252,675	1,120,756	1,204,335	1,192,588	3,027,421	0.394	1,192,588
AJAOKUTA*	292,723	15,515	-	102,746	200,954	0.511	102,746
OMOKU*	144,491	100,166	142,165	128,941	383,068	0.337	128,941
OMOTOSHO	77,386	306,060	237,795	207,080	340,640	0.608	207,080
GEREGU	588,640	637,675	281,792	502,702	856,010	0.587	502,702
OLORUN-SOGO	-	257,739	52,245	103,328	174,046	0.594	103,328
OFF GRID (<5 YRS)	-	-	-	-	24,975	0.673	151,359
IBOM*	-	-	1,078	359	1,068	0.337	359
TOTAL	9,016,108	8,287,869	5,869,855	7,724,611	15,277,746	-	8,935,616

**NOTE: For these IPP power plants, levels of fuel consumption are not published. Therefore, Option A2 in Option A in Step 4 of the "Tool to calculate the emission factor for an electricity system" is applied to these plants.*

For off-grid power plants, $EG_{m,y}$ is calculated by following *Option 3* and using the default value of 300 hours of operations of off grid plants as outlined in the tool for calculating emission factor for electricity production (see sheet "off grid 1" in Excel workbook "Afam PDD Baseline EF calculations v2.3_corrected").

From the data presented above, $EF_{grid,OMsimple,y}$ is calculated using the data presented in Table 18 as follows:

$\sum EG_{m,y} * EF_{EL,m,y}$	8,935,616
$\sum EG_{m,y}$	15,277,746
$\mathbf{EF_{grid,OMsimple,y}}$	**0.585**

Determination of emissions factor for OM using only grid connected power plants

In determining the emission factor for grid-connected only power plants, the same approach described previously and data as presented in Table 18 are used, with the exclusion of the off grid power plants from the analysis. This results in the following:

$\sum EG_{m,y} * EF_{EL,m,y}$	7,724,611
$\sum EG_{m,y}$	13,477,746
$\mathbf{EF_{grid,OMsimple,y}}$	**0.573**

The full calculations of the OM_{EF} – using data provided by PHCN – are presented in sheet "GRID ONLY Option 2" in the Excel workbook "Afam PDD Baseline EF calculations v2.3_corrected".

Determination of emissions factor for CM using grid-connected and off-grid power plants

As previously mentioned the combined margin emission factor is simply the average of the operating margin emission factor and the build margin emission factor. Drawing on the analysis presented above, for grid connected and off-grid power plants, and the resulting value for $EF_{grid,\ CM,y}$ equals:

$(EF_{grid,BM,y} * 0.5) + (EF_{grid,OM,simple,y} * 0.5) = (0.613 * 0.5) + (0.585 * 0.5) =$ **0.599 tCO_2/MWh.**

(see sheet "INCL OFF-GRID Option 2" in Excel workbook "Afam PDD Baseline EF calculations v2.3_corrected")**.**

Determination of emissions factor for CM using only grid connected power plants

Undertaking the same approach to calculate the combined margin for grid connected power plants only, the resulting value for $EF_{grid,\ CM,y}$ equals

$(EF_{grid,BM,y} * 0.5) + (EF_{grid,OM,simple,y} * 0.5) = (0.519 * 0.5) + (0.573 * 0.5) =$ **0.546 tCO_2/MWh.**

(see sheet "GRID ONLY Option 2" in Excel workbook "Afam PDD Baseline EF calculations v2.3_corrected")**.**

0.546 tCO_2/MWh is the $EF_{grid,CM,y}$ value applied for Option 2.

Option 3 - The emission factor of the technology (and fuel) identified as the most likely baseline scenario

The most likely technology that would be used instead of CCGT is OCGT plant and this has therefore been chosen for the calculation of Option 3. As per equation (3) the input parameters for this technology are as follows:

$COEF_{BL}$ = 0.0561 tCO_2e/GJ (IPCC default emission factor for natural gas)

η_{BL} = 39.5% (conservative default efficiency factor for new gas-fired OCGT units built after 2000, as contained in Annex I of the "Tool to calculate the emission factor of an electricity system" v2.2.1)

The resulting value for $EF_{BL,CO2}$ is calculated to be **0.511 tCO_2/MWh**

In summary, the following $EF_{BL,CO2}$ are applicable:

- Option 1 has a value of 0.519 tCO_2/MWh
- Option 2 has a value of 0.546 tCO_2/MWh
- Option 3 has a value of 0.511 tCO_2/MWh

Given that Option 3, the OCGT emission factor, is the lowest of the three calculated alternatives, Option 3 has been chosen as the basis for calculation of the baseline emissions factor $EF_{BL,CO2}$.

It is noted that this is significantly lower than the baseline emission factor for the off-grid diesel plant, which in reality is the most likely build margin and combined margin plant for Nigerian electricity supply (0.613 and 0.599 tCO_2/MWh respectively). Therefore, the proposed baseline emission calculation approach is **very conservative** compared with the actual situation in Nigeria.

Leakage emissions

There is no leakage associated with the project activity, because fugitive upstream CH_4 emissions from gas transformation and distribution apply to both the baseline and project scenario. The project will not give rise to increases fugitive emissions and, based upon a lower gas feed requirement, leakage emissions from arising from fugitive CH_4 emissions may be negative; however, for the purposes of simplicity and conservativeness $LE_{CH4,y}$ will be treated as zero. There will be no LNG consumption in the project activity, so $LE_{LNG,CO2,y}$ will be zero. Therefore, leakage emissions are calculated to be zero.

Emission reductions

Emission reductions have been calculated using the following equation:

$$ER_y = BE_y - PE_y - LE_y \qquad \textbf{(6)}$$

Where:

ER_y	=	emissions reductions in year y (tCO_2e)
BE_y	=	emissions in the baseline scenario in year y (tCO_2e)
PE_y	=	emissions in the project scenario in year y (tCO_2e)
LE_y	=	leakage in year y (tCO_2e)

B.6.2. Data and parameters fixed ex ante

Data / Parameter	$OXID_f$
Unit	-
Description	Oxidation factor of natural gas used in the calculation of project emissions.
Source of data	2006 IPCC Guidelines for National Greenhouse Gas Inventories (Volume 2: Energy; Chapter 2: Stationary Combustion; default value for stationary combustion sources)
Value(s) applied	1

Choice of data or Measurement methods and procedures	Not applicable
Purpose of data	For estimation of project emissions
Additional comment	None

Data / Parameter	$EF_{BL,CO2,y}$
Unit	tCO_2/MWh
Description	Baseline CO_2 emissions factor
Source of data	Fuel emissions coefficient (IPCC data) and the energy efficiency of the technology, as estimated in the baseline scenario analysis. See section B.6.1.
Value(s) applied	0.511 (see section B.6.1)
Choice of data or Measurement methods and procedures	Not applicable
Purpose of data	For estimation of baseline emissions
Additional comment	None

B.6.3. Ex ante calculation of emission reductions

The *ex ante* calculation of project emissions, baseline emissions, leakage emissions and emission reduction expected during the crediting period, applying all relevant equations provided in the methodology is presented below.

Project emissions:

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

Where (for project fuel; natural gas):

$FC_{f,1,y}$ = 1 054 203 429 m^3/yr[47]
$NCV_{f,y}$ = 0.035 GJ/m^3 (value for Nigerian gas reserves[48])
$EF_{CO2,f,y}$ = 0.0561 tCO_2/GJ (IPCC 2006 default factor)
$OXID_f$ = 1 (2006 IPCC Guidelines for National Greenhouse Gas Inventories default factor for stationary combustion sources)

$\boldsymbol{PE_y}$ = (1 054 203,429 x 0.035 x 0.0561 x 1) = **2 069 928 tCO_2/yr**

[47] FC is based on meter readings, of which details are provided in section B.7.1
[48] Enibe, S.O. and Odukwe, A.O. 'Patterns of Energy Consumption in Nigeria' University of Nigeria, 1990. See http://www.unn.edu.ng/home/index2.php?option=com_docman&task=doc_view&gid=18206&Itemid=306.

Baseline emissions:

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

Where:

$EG_{PJ,y}$ = 5 124.6 GWh/yr[49]
$EF_{BL,CO2,y}$ = 0.511 tCO_2/MWh (see sections B.6.1 and B.6.2)

$\boldsymbol{BE_y}$ = (5 124 600 x 0.511) = **2 620 163 tCO_2/yr**

Leakage emissions:

As described in section B.6.1, there are no leakage emissions associated with the project activity.

$\boldsymbol{LE_y}$ = **0 tCO_2/yr**

Emission reductions:

$ER_y = BE_y - PE_y - LE_y$

$\boldsymbol{ER_y}$ = (2 620 163 - 2 069 928 - 0) = **550 234 tCO_2/yr**

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

Table 19: 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)
01/11/2012 – 30/11/2013	2 620 163	2 069 928	0	550 234
01/11/2013 – 30/11/2014	2 620 163	2 069 928	0	550 234
01/11/2014 – 30/11/2015	2 620 163	2 069 928	0	550 234
01/11/2015 – 30/11/2016	2 620 163	2 069 928	0	550 234
01/11/2016 – 30/11/2017	2 620 163	2 069 928	0	550 234
01/11/2017 – 30/11/2018	2 620 163	2 069 928	0	550 234
01/11/2018 – 30/11/2019	2 620 163	2 069 928	0	550 234
01/11/2019 – 30/11/2020	2 620 163	2 069 928	0	550 234
01/11/2020 – 30/11/2021	2 620 163	2 069 928	0	550 234
01/11/2021 – 30/11/2022	2 620 163	2 069 928	0	550 234
Total	**26 201 630**	**20 699 280**	**0**	**5 502 340**
Total number of crediting years	10			
Annual average over the crediting period	2,620,163	2,069,928	0	550,234

[49] EG factor based on meter readings, for which details are provided in section B.7.1

B.7. Monitoring plan

Title: Approved monitoring methodology **AM0029 (Version 3)** "Grid Connected Electricity Generation Plants using Non-Renewable and Less GHG Intensive Fuel."

The project activity is a natural gas based power generation project, which feeds electricity (power) to the regional grid in Nigeria. The project activity meets the methodology applicability criteria which are as follows:

1. The project activity is the construction and operation of a new natural gas fired grid connected electricity generation plant;
2. The geographical/ physical boundaries of the baseline grid are clearly identified and information pertaining to the grid and estimating baseline emissions is publicly available; and
3. Natural gas is sufficiently available in Nigeria. Future natural gas based power capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in this project activity.

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

The monitoring methodology requires the following parameters to be monitored during the crediting period:

For project emissions:

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

Baseline emissions will be monitored as per the "Tool to calculate emission factor for an electricity system", as applicable. Therefore, according to Option 3 used in the choice of baseline emissions factor, EF_{BL} (as described above), parameters $EG_{PJ,y}$ and $COEF_{BL}$ must be monitored. Note that in this context $COEF_{BL}$ is the same parameter as $EF_{CO2,f,y}$ i.e. CO_2 factor for natural gas combustion (tCO_2/GJ). The data and parameters to be monitored according to the methodology as described below.

B.7.1. Data and parameters to be monitored

Data / Parameter	$FC_{f,1,y}$
Unit	m^3
Description	Annual quantity of fuel (natural gas) consumed in project activity
Source of data	Fuel (natural gas) flow meter reading at Afam plant gas reception facilities (custody transfer point from supplier; point 1 in Figure A4.1)
Value(s) applied	1 054 203 429 m^3
Measurement methods and procedures	Continuous metering of gas supply both at supplier (Okoloma gas plant) and project end for cross verification and measured in standard cubic meters (m^3).

Monitoring frequency	Continuous
QA/QC procedures	Natural gas supply metering (Elster Instromet 2000) to the project will be subject to regular (in accordance with stipulation of the meter supplier) maintenance and testing to ensure accuracy.
Purpose of data	For estimation of project emissions
Additional comment	

Data / Parameter	$FC_{f,2,y}$
Unit	m^3
Description	Annual quantity of fuel (natural gas) consumed in gas turbine #11
Source of data	Fuel (natural gas) flow meter reading at turbine #11 inlet (SM R1-X-K G1600 Elster Instromet meter located at point 2 in Figure A4.1)
Value(s) applied	351 401 143 m^3
Measurement methods and procedures	Daily meter reading
Monitoring frequency	Continuous
QA/QC procedures	Used to corroborate gas consumption data collected at point 1
Purpose of data	For estimation of project emissions
Additional comment	

Data / Parameter	$FC_{f,3,y}$
Unit	m^3
Description	Annual quantity of fuel (natural gas) consumed in gas turbine #12
Source of data	Fuel (natural gas) flow meter reading at turbine #12 inlet (SM R1-X-K G1600 Elster Instromet meter located at point 3 in Figure A4.1)
Value(s) applied	351 401 143 m^3
Measurement methods and procedures	Daily meter reading
Monitoring frequency	Continuous
QA/QC procedures	Used to corroborate gas consumption data collected at point 1
Purpose of data	For estimation of project emissions
Additional comment	

Data / Parameter	$FC_{f,4,y}$
Unit	m^3
Description	Annual quantity of fuel (natural gas) consumed in gas turbine #13
Source of data	Fuel (natural gas) flow meter reading at turbine #13 inlet (SM R1-X-K G1600 Elster Instromet meter located at point 4 in Figure A4.1)
Value(s) applied	338 944 917 m^3

Measurement methods and procedures	Daily meter reading
Monitoring frequency	Continuous
QA/QC procedures	Used to corroborate gas consumption data collected at point 1
Purpose of data	For estimation of project emissions
Additional comment	

Data / Parameter	$NCV_{f,y}$
Unit	GJ/m^3
Description	The net calorific value (energy content) per volume unit of natural gas used in the calculation of project emissions.
Source of data	Based on fortnightly sampling at the Afam plant gas reception point (point 1 in Figure A4.1)
Value(s) applied	0.035 GJ/m^3 (The value chosen represents an estimate of NCV for Nigerian natural gas reserves. *Source: Enibe, S.O. and Odukwe, A.O. 'Patterns of Energy Consumption in Nigeria'* University of Nigeria, 1990)
Measurement methods and procedures	Gas samples collected using SPDC standard gas sampling protocol and analysed using standard gas chromatography techniques in on-site laboratory. Fortnightly sampling and analysis to be carried out in accordance with AM0029.
Monitoring frequency	Fortnightly
QA/QC procedures	The calorific value of the gas will be recorded by the project participant and cross-checked against measurements made, and provided, by the gas supplier.
Purpose of data	For estimation of project emissions
Additional comment	

Data / Parameter	$EF_{CO2,f,y}$
Unit	tCO_2/GJ
Description	CO_2 emission factor per unit of energy of natural gas used in the calculation of project emissions.
Source of data	Based on fortnightly sampling at the Afam plant gas reception point (point 1 in Figure A4.1)
Value(s) applied	0.0561 (IPCC default for natural gas, 2006)
Measurement methods and procedures	Gas samples collected using SPDC standard gas sampling protocol and analysed using standard gas chromatography techniques in on-site laboratory. Fortnightly sampling and analysis to be carried out. Minimum measurement – yearly in accordance with the AM0029.

Monitoring frequency	Fortnightly
QA/QC procedures	The CO_2 content of the gas will be recorded by the project participant and cross-checked against measurements made, and provided, by the gas supplier.
Purpose of data	For estimation of project emissions
Additional comment	

Data / Parameter	$EG_{PJ, 5,y}$
Unit	MWh
Description	Electricity produced by gas turbines (GT 12 & GT 13)
Source of data	Electricity meters installed in the plant power export point to bus-bar (meter type EDMI MK6E with accuracy class 0.2S. IEC62052-11 / 62053-22)
Value(s) applied	3 547 800 MWh
Measurement methods and procedures	Continuous metering of electricity supplied by the gas turbines to the bus-bar of the Afam plant
Monitoring frequency	Continuous
QA/QC procedures	Metered export of electricity to be checked against data on power received by the grid operator (PHCN) at the Afam plant-grid interface points. Accuracy of meters are to be tested every 180 days as outlined in section 7.3 of the PPA and calibration of meters needs to be undertaken if electrical energy measured by the system differs by over half a percent (0.5%) from any back-up system.
Purpose of data	For estimation of baseline emissions
Additional comment	

Data / Parameter	$EG_{PJ, 6,y}$
Unit	MWh
Description	Electricity produced by gas turbine and steam turbine (GT 11 & ST)
Source of data	Electricity meters installed in the plant power export point to bus-bar.(meter type EDMI MK6E with accuracy class 0.2S/0,55. IEC62053-22/62052/11)
Value(s) applied	1 576 800 MWh
Measurement methods and procedures	Continuous metering of electricity supplied by the steam turbine to the bus-bar of the Afam plant.
Monitoring frequency	Continuous
QA/QC procedures	Metered export of electricity to be checked against data on power received by the grid operator (PHCN) at the Afam plant-grid interface points. Accuracy of meters are to be tested every 180 days as outlined in section 7.3 of the PPA and calibration of meters needs to be undertaken if electrical energy measured by the system differs by over half a percent (0.5%) from any back-up system.
Purpose of data	For estimation of baseline emissions

Additional comment	

B.7.2. Sampling plan

Not applicable for this project activity

B.7.3. Other elements of monitoring plan

The monitoring information will be collected routinely as part of good practice and input into Shell Petroleum and Development Company of Nigeria's greenhouse gas reporting system.

All procedures for collecting data are outlined in the *Afam VI Power Project Operations and Maintenance Reports*. Responsible personnel will be identified and briefed on their responsibilities in light of the monitoring plan described in the previous section (i.e. meter locations, calibration requirements, monitoring frequency, recording methodology).

All data will be recorded in a purpose built MS Excel spreadsheet. Data will be stored on SPDCs' computer server and backed up regularly.

B.7.4. Date of completion of application of methodology and standardized baseline and contact information of responsible persons/ entities

Date: Final version submitted: 05/07/2012

Persons undertaking the baseline calculation:

Frederik Beelitz /Peter Robinson, Economic Consulting Associates (ECA)
41 Lonsdale Road, London NW6 6RA, UK
Tel: +44 (0)20 7604 4546
Fax: +44 (0)20 7604 4547

Greg Cook/Paul Zakkour, Carbon Counts
5 Dalby Road, London SW18 1AW, UK
Tel: +44 (0)20 8870 3330
Email: enquiries@carbon-counts.com

SECTION C. Duration and crediting period

C.1. Duration of project activity

C.1.1. Start date of project activity

9 December 2005. This is the date when the Engineering, Procurement and Construction (EPC) project contract was signed between Shell and Daewoo and includes cost estimates

for the Long Term Service Agreement (LTSA). The EPC and LTSA are therefore contained in the same document[50]. It is therefore in alignment with the definition provided in the CDM Glossary of Terms which states that *"the start date shall be considered to be the date on which the project participant has committed to expenditures related to the implementation or related to the construction of the project activity. This, for example, can be the date on which contracts have been signed for equipment or construction/operation services required for the project activity....."*

C.1.2. Expected operational lifetime of project activity

Twenty (20) years.

C.2. Crediting period of project activity

C.2.1. Type of crediting period

Fixed term crediting period

C.2.2. Start date of crediting period

1st November 2012

C.2.3. Length of crediting period

10 years (120 months)

SECTION D. Environmental impacts

D.1. Analysis of environmental impacts

An Environmental Impact Assessment (EIA) for the Afam Power Plant Project was completed in November 2004 and approved by the Nigerian Federal Ministry of Environment on 9 June 2005 (see Figure 7 below). The full EIA is available upon request from the project proponent.

[50] Shell Petroleum Development Company of Nigeria, Company Cost Estimate, Afam power Plant EPC and LTSA Contracts, Tender No: E – 16618, October 2005

Figure 7: Afam Power Plant Project Environmental Impact Statement Certificate

FMENV/EIA/ 000169

FEDERAL MINISTRY OF ENVIRONMENT
ENVIRONMENTAL IMPACT STATEMENT
&
Certificate

1. Project Identity: AFAM POWER PLANT PROJECT
2. Proposed date of project commencement: 9th June 2005
3. Project Proponent: THE SHELL PETROLEUM COMPANY OF NIGERIA LIMITED
4. Project Location: OYIGBO LGA, RIVERS STATE

COMMENTS: (i) There shall be full implementation of the Environmental Management Plan (EMP) of the Project (ii) There shall be Impact Mitigation Monitoring of the Project by the FMENV in collaboration with other relevant Authorities, which shall be facilitated by SPDC (iii) SPDC shall put in place adequate waste water treatment for effective processing of plants effluent to prevent pollution of Imo River

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 AFAM POWER PLANT PROJECT
Project as proposed may proceed subject to above comments.

Date of Issue: 9th June 2005 Expiry Date: 8th June 2010

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.

An overview of the key conclusions of this study is provided below (section D.2).

D.2. Environmental impact assessment

In line with the national regulatory requirements of the Federal Ministry of Environment (FMENV), the Department of Petroleum Resources (DPR) and SPDC's Environmental Policy, a detailed Environmental Impact Assessment (EIA) of the Afam Power Plant Project has been prepared in order to ensure that the project activities are executed without adverse effect on the environment. The EIA study was based on existing information on this area, site-specific fieldwork, laboratory analysis of samples, consultations (with host communities and other stakeholders) and a number of workshops involving consultants and other stakeholders including regulatory agencies.

An Environmental Management Plan (EMP) has been developed so that the mitigation measures prescribed in the EIA document can be implemented (the EMP forms Chapter 6 of the EIA report). The EMP includes a programme of environmental monitoring to assess the efficacy of the mitigation measures and to identify any impact arising from the project that has not been addressed in the EIA. Therefore the overall impacts associated with the proposed project can be managed within responsible and acceptable limits by applying the mitigation measures and management strategy outlined in the EMP.

A summary of the major impacts and mitigation measures identified in the EIA is provided in Table 20.

Table 20: Summary of major impacts and mitigation measures

Project phase	Description of impact	Significance rating before (and after) mitigation	Mitigation
Construction	Influx of people	High (Medium)	• EPC Contractor shall make available a detailed housing plan to the SPDC project manager prior to mobilization.
	Alteration of natural soil profile	Medium (Low)	• SPDC shall ensure that EPC contractor minimises topsoil removal so that quarried laterite brought in from another location does not tremendously alter the natural soil profile of original location.
	Soil Degradation and Soil/Groundwater Contamination	Medium (Low)	• SPDC shall ensure that EPC contractor provides containment for chemicals and liquid discharges. • SPDC waste management policy shall be enforced in cases of domestic rubbish/trash, scrap metals, non-plastic combustible packaging materials, plastic packing materials, drums and containers as well as medical wastes. • SPDC shall ensure that a controlled fuelling, maintenance and servicing protocol for construction machinery at worksite is established and followed • SPDC shall ensure that a liquid (condensate) knock out facility is installed in the gas supply system and that approximate means to store and dispose of this liquid is provided in the design and construction of the plant.
	Pollution of Imo River	Medium (Low)	• SPDC shall ensure that EPC Contractor provides containment for chemicals and liquid discharges. • SPDC shall ensure that clearing is during dry season to minimise run-off into water bodies. • SPDC waste management policy shall be enforced.
	Reduction in air quality	Medium (Low)	• SPDC shall ensure that all mobile and stationary internal combustion engines are properly maintained; • SPDC shall ensure that water is sprayed to reduce dust in air during construction in the dry season.
	Increase in respiratory diseases	High (Low)	• Nose masks shall be worn by site workers during (dusty) operations. • Water shall be sprayed on construction site to reduce dust levels especially during dry season. • Pre-mob inspections and regular maintenance of equipment shall be conducted. • Upgrade and support of existing health services and facilities (NEPA). • SPDC yellow guide for health shall be implemented. • Construction workers shall be compelled to wear PPEs equipment.

Project phase	Description of impact	Significance rating before (and after) mitigation	Mitigation
	Reduction in biodiversity /loss of flora and fauna	Medium (Low)	• SPDC shall limit cleared area to what is required • Site clearing shall commence from developed (e.g. roads) to undeveloped areas to provide escape routes for wildlife. • SPDC shall encourage the EPC contractor to educate construction workers and locals on the sensitive nature of the biodiversity of the area and the need for conservation. • Hunting by employees of EPC/other Contractors shall be prohibited • SPDC shall support local capacity building through skills enhancement to facilitate occupational re-adjustment. • SPDC shall encourage the EPC contractor to re-vegetate land cleared for temporary use where feasible.
	Increase in noise nuisance	High (Low)	• SPDC shall ensure that EPC contractor enforces existing night driving policy of SPDC. • EPC contractor shall plan activities such that World Bank limits shall not be exceeded at the nearest community(ies). • Communities shall be consulted by the EPC contractor prior to periods of expected peak noise levels.
Operation	Injury / fatalities in workforce/ communities	Medium (Low)	• Compulsory medical fitness test for all SPDC and contractor personnel. • First Aid training of workforce (i.e. 1:50). • Upgrade of existing NEPA clinic to include emergency unit. Emergency response procedure shall be put in place and administered. • Safety awareness training for workforce and selected representatives of main communities (Ayama and Okoloma).
	Pollution of Imo River	Medium (Low)	• SPDC shall ensure that waste water and other effluents discharged into Imo River are treated to meet FMENV and World Bank guidelines for new plants especially where initial mixing with Imo River takes place. • Potentially contaminated storm water collected from roads shall be routed to a buffer tank and oil separator. • All chemically contaminated effluents shall be routed to a neutralization pit where they will be neutralized/ treated and routed to a balancing tank from where they will be routed to the common discharge. • SPDC waste management policy shall be enforced.

Project phase	Description of impact	Significance rating before (and after) mitigation	Mitigation
	Increase in respiratory diseases	Medium (Low)	• Nose masks shall be worn by site workers during (dusty) operations. • Water shall be sprayed on construction site to reduce dust levels especially during dry season. • Pre-mob inspections and regular maintenance of equipment shall be conducted. • Upgrade and support of existing health services and facilities (NEPA). • SPDC yellow guide for health shall be implemented. • Construction workers shall be compelled to wear PPEs equipment.
	Reduction in air quality	Medium (Low)	• SPDC shall ensure that all mobile and stationary internal combustion engines are properly maintained.
	Soil Degradation and soil/Groundwater contamination	Medium (Low)	• Provide containment for chemicals and liquid discharges; • SPDC waste management policy shall be enforced.
	Risk/exposure to electric shock	Medium (Low)	• SPDC shall ensure that O&M contractor staff strictly adheres to known safety procedures, when work is in progress.
Demolition	Increase in dust generation	High (Low)	• Demolition contractor shall take inventories of all materials that are likely to be encountered. • Positively identify and categorize all waste types; • Establish a procedure to manage the dislodgement process • Put a waste management plan in place; • Ensure that demolition process is subject to regulatory approval; • Ensure that adequate emergency response procedures are in place; • Ensure proper use of PPE by site workers.
	Injury/fatalities in workforce/ communities	Medium (Low)	• Compulsory medical fitness test for all SPDC and contractor personnel. • First Aid training of workforce (i.e. 1:50). • Upgrade of existing NEPA clinic to include emergency unit. • Safety awareness training for workforce and selected representatives of main communities (Ayama and Okoloma).
	Increase in respiratory diseases	High (Low)	• Demolition contractor shall establish occupational health monitoring for site workers; • Enforce use of nose masks and other PPEs; • Provide special training for those handling asbestos.

The EIA also assesses the key benefits associated with the Afam power project, and how these positive impacts can be enhanced. There are briefly described below.

Job creation and economic enhancement

A total of 877 (678 skilled, 131-semi-skilled and 69 unskilled) persons, mainly from the neighbouring communities are to be employed by the project during construction phase. Once in operation, the project will employ 50 skilled persons. These jobs will continue over the estimated project duration (20 years). During the demolition phase, jobs are also expected to be available for locals and nationals even if at a lower rate than during the construction phase. So as to ensure enhanced job creation opportunities throughout the life of the project, SPDC shall ensure that all subcontracts for supplies and minor repairs are reserved for qualified contractors from the project area in the first instance. The surveys of the communities revealed many workers with some skills, which may not meet the required standards for the project. SPDC shall suggest to the EPC & O&M contractors that such persons and local contractors from these communities could formally register with a skills' registration centre, which could be established for the project so that initial considerations shall be given to them for employment and contracts.

As part of sustainable approach to community interaction, SPDC, under its community development programme (CDP) shall embark on the necessary support, which shall include micro-credit schemes, to the communities such that they take advantage of the business opportunities available at Afam as a result of this project.

Increase in efficiency of gas use and electricity generation

The Afam power project will increase the available on-grid power generation capacity in Nigeria, reducing the self-generation that many households and businesses would otherwise need to fall back on. The project will achieve this increase in reliability and reduction in economic cost to consumers with substantially lower emissions than the more financially attractive open-cycle project alternative and with far lower emissions than consumer self-generation form diesel would produce for the same output.

The amount of gas slated for use and the planned power generation capacity represent a potential for significant improvement over existing historical data on gas use and power generation at Afam. The power station shall be operated for 20 years and proper maintenance shall ensure breakdown of the plant is avoided and output is maintained. Guaranteed electricity output would improve industrial and domestic activities within the country. Given the history of successful private sector participation in business which SPDC is expected to bring into the power sector and the power purchase agreement with NEPA, the plant is most likely to be run better, hence, efficiency of gas use and power generation will increase.

Improvement of local infrastructure

The project will encourage improvement in existing infrastructure, for example, rehabilitation of the local NEPA School and clinic, widening and upgrading of the existing access to a new campsite; maintenance of the Oyigbo-Afam Road; and rerouting of part of the Oyigbo-Afam Road. These constitute positive project impacts which shall be enhanced by extending this programme on facilities improvement to some community facilities, e.g. the existing primary school at Okoloma.

Skills development and training

The project provides important employment, training and development opportunities for the local community. As well as training of selected NEPA and other qualified Nigerians in acquiring new skills for the operation and maintenance of the turbines, opportunities for turbine-related technology training have been extended to some locals and nationals who would not be hired for the project but could put their newly acquired training and experience to good use in appropriate locations elsewhere in the country given the proposals by NEPA and other bodies to build more power plants. As part of the project development, 140 youths from neighbouring communities will be given Workforce training in areas such as welding to enable them acquire skills that will open up to them future employment opportunities. It will also facilitate technology transfer by building up the capacity in Nigeria for the operation of CCGT power plants.

SECTION E. Local stakeholder consultation

E.1. Solicitation of comments from local stakeholders

It is the policy of SPDC to consult with stakeholders and relevant authorities in all its activities and the New SPDC EIA process manual requires that such consultation should take place. The three key stakeholders most relevant to the Afam power project have been identified as the local communities, government agencies, and the project main contractor. There are a total of 14 major communities and 32 satellite communities impacted by the project.

A key stated objective of the project EIA was to integrate the opinions and views of all stakeholders, particularly host communities into the project design in order to ensure that the completed project is both environmentally and socially sustainable. An initial scoping workshop to consult with stakeholders was convened in Port Harcourt on June 19, 2003, the primary objective of which was to identify the terms of reference and context of the EIA (see Section D). This workshop was attended by:

- Four representatives of each of the communities involved;
- Representatives from the federal and state government regulators: Federal Ministry of Environment (FMENV); Department of Petroleum Resources (DPR); Rivers State Ministry of Environment;
- Representatives of Oyigbo Local Government within which the project is located;
- Key project staff from SPDC;
- Non Governmental Organisations (NGOs) - representatives from the Living Earth Foundation and the Nigerian Environmental Society.

The broad objectives of the workshop were:

- Education and enlightenment of identified stakeholders (communities, Government agencies, non-governmental organizations (NGOs), community based organizations (CBOs) etc., on the need for their involvement in the conduct of the study and to assist the project team in articulating the concerns of the communities as well as those of their immediate environment;
- Building trust and confidence that would enhance the capacities of the identified stakeholders through participation in the project.
- Forming and promoting partnership with identified stakeholders through networking, information sharing and participation in consultation exercises.

The identified community stakeholders were informed by means of visits of their expected participation during the commencement of fieldwork. At the field locations, the study team met the Chief/Paramount Ruler, the Chairman of the Community Development Committee (CDC), the Women leader and the youth leader and discussed the objectives of the study. This helped in securing the social license to conduct baseline studies in these communities. Consultation with other stakeholders is ongoing and shall be sustained throughout the duration of the project. The record of consultation undertaken as part of the EIA process is shown in Table 21 below.

Table 21: Stakeholder consultation events

Date(s)	Stakeholders	Event
April 8, 2002	SPDC Afam Project Team & Okoloma representatives	Courtesy visit to Okoloma, landlord
October 16, 2002	SPDC & Okoloma community	Consultation with community on proposed EIA study
February 7, 2004	NEPA	Letter of permission granted to SPDC to enter NEPA Afam facilities
March 13, 2003	Egberu Community	Letter of request for inclusion in EIA study for Afam Power Plant
March 17, 2003	Egberu Community	Letter of nomination of Egberu community representatives for the EIA studies for Afam Power Plant
March 20, 2003	SPDC CLO, EIA consultant, Okoloma & Ayama community reps.	Meeting with communities for the Afam Power Plant field work
June 19, 2003	8 communities, FMENV, RSMENV, ASMENV, Oyigbo LGA Chairman, NGOs & SPDC Afam Project Team	EIA Scoping workshop
March 16, 2004	SPDC Afam Project Team, NEPA management & unions (NUEE & SSA)	Meeting to present the questionnaire to be administered to the NEPA staff
March 29 to April 2 2004	Afam EIA consultants, FMENV, RSMENV, NES, NEPA, SPDC Afam Team & SGSI	Workshop on the new EIA process of SPDC and the integration of the biophysical, social and health data into the EIA
March 18th 2010	All 16 Afam Communities, NNPC, Shell Afam Team	Stakeholders CDM engagement meeting

An EIA Feedback Session (Open Forum) with Stakeholders for the Afam Power Plant project was subsequently held on Tuesday, September 14, 2004 in Port Harcourt. The session was used to discuss the findings of the EIA with the same stakeholders who were present at the Scoping Workshop of June 19, 2003. A representative of the National Inland Waterways Authority was present at this session. The feedback from this session was incorporated into the Afam power project EIA report and Environmental Management Plan.

A broader Stakeholders Engagement Plan was subsequently developed for the Afam Integrated Gas and Power Project in June 2005 (document number: AFM-TPI-000-F01-00003). Its objectives are:

1. To identify and relate with the stakeholders within the Afam Integrated Gas and Power Project environment
2. To create awareness and communicate the details of the planned Afam Integrated Gas and Power Project.
3. To understand Community's perceptions and concerns about the project.
4. Sensitize Stakeholders on their expected roles and Responsibilities to the success of the project.
5. To decide and agree Community Development interventions and strategies.
6. To sensitize stakeholders on ESHMP process.
7. To identify opportunities for local Capacity building and Community Development.

The Stakeholder Engagement Plan describes how external stakeholder engagement and campaigns have been approached according to four levels of engagement, as summarized in Table 22 below:

Table 22: External Stakeholder Engagement plan

Levels/Dates	Objectives	Target group	Frequency of Meeting
Level 1 General Top Level leaders Date: July, 2005	Create awareness and Build Partnership; Understand project, SD, SCD approach, PAC model, Government role/support, obtain feedback, Appreciate Roles	State Governments (Rivers and Abia)	Yearly meeting
Level 2 Government Officials, Media Chiefs, Community leadership/ Active leaders in the field Date: July, 2005	Understand project, SD, SCD approach, PAC model, Government role/support, Obtain feedback: Build partnership for field execution of project; understand specific requirements from each	State Government Focal Points Hon members of State Houses of assembly LGA Chairmen Police Commissioners CO, Nigerian Navy JTF NDDC	Yearly
Level 3 Grassroots fora / parliament Per community & satellite settlements Date: July, 2005.	Create awareness and appreciation of project and CR approach. Appreciate obligations from all parties	Reps of all segments of the communities. 200 - 350 persons per community	Yearly
Level 4 Youth Forum, Community youth leaders and Council counsellors Date: August, 2005	Create awareness for the project, Regular communication session, and establish a grievances communication structure.	Youth leaders from the major Communities and elected council counsellors. 2 representative per Community 10, OYILGA and 2 Ukwa-west Counsellors. Total: 40 persons.	Quarterly

Each of the four levels of stakeholder engagement has involved the development of a number of workshops, open fora and meetings involving a large range of stakeholders. Further details of the stakeholder consultation process are contained in Appendix D of the full EIA Report and in the Afam Integrated Gas and Power Project Stakeholder Engagement Plan (both documents will be made available to the validator).

A further stakeholder engagement workshop was held by SPDC on 18 March 2010 in order to communicate the potential benefits associated with the Afam power project, the objectives of the CDM and to seek feedback from those communities affected. The event was attended by 53 leaders and representatives from those communities affected by the project including the Okoloma, Egberu, Komkom, Afam-Nta, Ayama, Izuoma, Umuosi, Mgbosi and Oyigbo communities.

E.2. Summary of comments received

Comments received from the stakeholders including local communities have been included in the Afam project design from an early planning stage through to construction, as an integral part of the EIA process. Detailed comments and written feedback provided during several events held as part of the stakeholder engagement process associated with the EIA are provided in Appendix D of the full EIA Report.

Written comments were also received during the stakeholder engagement workshop held on 18 March 2010. Detailed feedback was provided by 24 individuals representing those communities affected by the project. These are provided as copies available to the validator. A wide range of comments were received during the event, covering a range of issues and potential concerns. These are summarised in Table 23 below, grouped into positive impacts and negative impacts (and/or concerns) identified in connection with the project.

Table 23: Summary of stakeholder workshop responses

Issue	Number of written comments
Positive impacts associated with Afam power project	**20**
Increased employment, business growth, prosperity and development	8
Increased reliability of electricity supply to communities	3
Improved levels of other community services (water, roads, education)	2
The project will lead to reduced CO_2 emissions	2
Positive overall improvement to community (benefits unspecified)	2
Electricity has replaced reliance on wood or generators as a primary energy source	2
Reduced noise pollution (associated with generator usage)	1
Negative impacts (and/or concerns raised) associated with Afam power project	**12**
Electricity supply problems remain in some communities	3
Gas flaring has continued	3
Economic and employment benefits have not been felt	3
Increased noise pollution	1
Influx of people has lead to increased social vices and security issues	1
No overall improvement to community	1

The stakeholder workshop and written comments indicate that the communities feel that they have benefited overall from the Afam power project, most noticeably through the increased supply (and reliability) of grid electricity and the creation of jobs, skills and regional economic development. Several community representatives also noted the positive environmental and health impacts associated with the project, relating to the displacement of diesel-powered generators and wood used in home energy provision.

Despite these benefits, several key concerns were raised. These included comments expressing the view that the expected economic and employment benefits arising from the project had not been felt in a particular community, and that electricity supply had not improved. Several stakeholders also suggested that gas flaring had not been reduced from the Afam project as expected. There was some indication that benefits had not been felt similarly across the affected region, with certain communities expressing the view that they had not significantly benefited from the project, most noticeably the Kom kom and Oyigbo communities.

E.3. Report on consideration of comments received

It is the policy of SPDC to take into consideration all concerns and suggestions of stakeholders during the design, construction and implementation of all projects. During the project implementation SPDC organised various stakeholders meetings and discussion groups, and the suggestions made – and concerns raised - have been integrated into the project design.

Further details of how the stakeholder issues and concerns have been included in to the implementation and management of the project are contained in Appendix 2 'Stakeholders Analysis' of the Afam Integrated Gas and Power Project Stakeholder Engagement Plan (both documents will be made available to the validator).

SECTION F. Approval and authorization

The Host Country Approval and Authorization from Federal Ministry of Environment, Special Climate Change Unit, Government of Nigeria received on 21st June 2010 vide Letter No. FMENV/SCCU/SPDC/21/06/10.

- - - - -

Appendix 1. Contact information of project participants and responsible persons/ entities

Project participant and/or responsible person/ entity	☒ Project participant ☐ Responsible person/ entity for application of the selected methodology (ies) and, where applicable, the selected standardized baselines to the project activity
Organization name	Shell Petroleum Development Company of Nigeria Limited
Street/P.O. Box	P O Box 263 Port Harcourt, Nigeria
Building	
City	Port Harcourt
State/Region	Rivers State
Postcode	263
Country	Nigeria
Telephone	+234 807 0221027
Fax	
E-mail	C.Ozumba@Shell.com
Website	www.shell.com
Contact person	Chinyere Ozumba
Title	Dr
Salutation	
Last name	Ozumba
Middle name	
First name	Chinyere
Department	Biodiversity Conservation and CO2/CDM
Mobile	
Direct fax	
Direct tel.	+234 807 0221027
Personal e-mail	

Project participant and/or responsible person/ entity	☐ Project participant ☒ Responsible person/ entity for application of the selected methodology (ies) and, where applicable, the selected standardized baselines to the project activity
Organization name	Economic Consulting Associates (ECA)
Street/P.O. Box	41 Lonsdale Road, London
Building	
City	London
State/Region	London
Postcode	NW6 6RA, UK
Country	United Kingdom
Telephone	+44 (0)20 7604 4546
Fax	
E-mail	info@eca-uk.com
Website	

Contact person	Frederik Beelitz
Title	
Salutation	
Last name	Beelitz
Middle name	
First name	Frederik
Department	Consultancy
Mobile	
Direct fax	
Direct tel.	+44 (0)20 7604 4546
Personal e-mail	

Project participant and/or responsible person/ entity	☐ Project participant ☒ Responsible person/ entity for application of the selected methodology (ies) and, where applicable, the selected standardized baselines to the project activity
Organization name	Carbon Counts
Street/P.O. Box	5 Dalby Road, London
Building	
City	London
State/Region	London
Postcode	SW18 1AW, UK
Country	United Kingdom
Telephone	+44 (0)20 8870 3330
Fax	
E-mail	enquiries@carbon-counts.com
Website	www.carbon-counts.com
Contact person	Greg Cook
Title	
Salutation	
Last name	Cook
Middle name	
First name	Greg
Department	Consultancy
Mobile	
Direct fax	
Direct tel.	+44 (0)20 8870 3330
Personal e-mail	

Appendix 2. Affirmation regarding public funding

Not applicable. There is no public funding for this project activity.

Appendix 3. Applicability of methodology and standardized baseline

The choice and description of baseline scenario is included in section B.4 and the choice and calculation of the baseline emissions factor is described in section B.6. As explained in the main body of the PDD, the full calculations and underlying data are provided for (a) the grid-only power plants, and (b) the use of grid power plus off-grid power in the Excel workbook “Afam PDD Baseline EF calculations v2.3_corrected”

For the purposes of calculating the Baseline EF for this project, only the GRID calculations have been used.

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

Not applicable

Appendix 5. Further background information on monitoring plan

The monitoring information contained in this Annex is provided in line with the approved monitoring methodology AM0029 and complements the information provided under sections B.6 and B.7. The purpose of this Annex is to facilitate preparation of the monitoring reports during the crediting period for the CDM project activity.

Table A4.1 provides details for each of the monitoring points in compliance with the monitoring requirements of AM0029. The monitored data parameters referred to in Table A4.1 refer to the specific monitoring points illustrated in Figure A4.1 below.

Figure A4.1. Monitoring points for natural gas consumption ($FC_{f,y}$) and electricity generation ($EG_{PJ,y}$).

Schematic for The CDM Monitoring Points

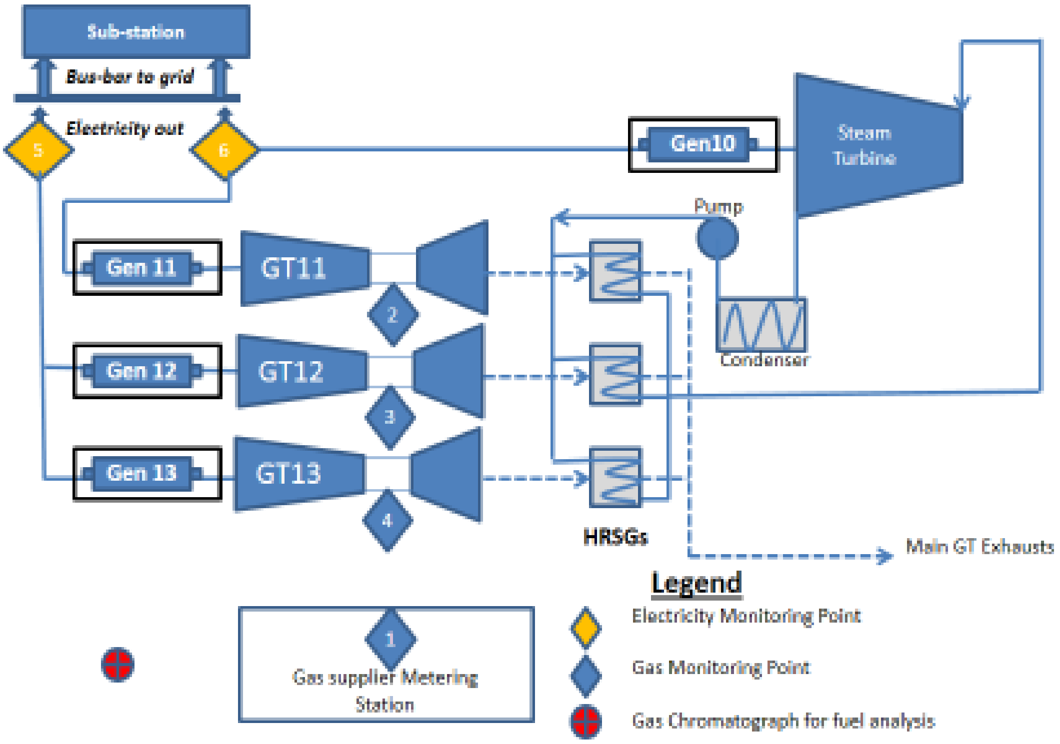


Table A4.1. Monitoring information for parameters required to calculated emissions reductions (ER_y)

Data/ Parameter	Data Unit	Description	Source of data	Measured (m), calculated (c), or estimated (e)	Recording frequency	Proportion of data to be monitored	Data archiving (electronic / paper)	QA/QC procedures to be applied	Person(s) responsible for:		
									Measurement	Calibration	Verification
$FC_{f,1,y}$	m³	Annual quantity of fuel (natural gas) consumed in project activity	Fuel (natural gas) flow meter reading at Afam plant gas reception facilities (custody transfer point from supplier; point 1 in Figure A4.1)	m	Continuous metering of gas supply; recorded daily	100%	Electronic	Natural gas supply metering (Elster Instromet 2000) to the project will be subject to regular (in accordance with stipulation of the meter supplier) maintenance and testing to ensure accuracy.	Gas entering plant recorded daily by Operator	To be carried out annually according to meter supplier methods	Verification with gas supply reading (Okolama Gas Plant) undertaken by Operations Manager
$FC_{f,2,y}$	m³	Annual quantity of fuel (natural gas) consumed in gas turbine #11	Fuel (natural gas) flow meter reading at turbine #1 inlet (SM R1-X-K G1600 Elster Instromet located at point 2 in Figure A4.1)	m	Daily meter reading	100%	Electronic	Used to corroborate gas consumption data collected at metering point 1	Gas entering plant recorded daily by Operator	To be carried out annually according to meter supplier methods	Verification with gas metering point 1 undertaken by Operations Manager
$FC_{f,3,y}$	m³	Annual quantity of fuel (natural gas) consumed in gas turbine #12	Fuel (natural gas) flow meter reading at turbine #2 inlet (SM R1-X-K G1600 Elster Instromet located at point 3 in Figure A4.1)	m	Daily meter reading	100%	Electronic	Used to corroborate gas consumption data collected at metering point 1	Gas entering plant recorded daily by Operator	To be carried out annually according to meter supplier methods	Verification with gas metering point 1 undertaken by Operations Manager
$FC_{f,4,y}$	m³	Annual quantity of fuel (natural gas) consumed in gas turbine #13	Fuel (natural gas) flow meter reading at turbine #3 inlet (SM R1-X-K G1600 Elster Instromet located at point 4 in Figure A4.1)	m	Daily meter reading	100%	Electronic	Used to corroborate gas consumption data collected at metering point 1	Gas entering plant recorded daily by Operator	To be carried out annually according to meter supplier methods	Verification with gas metering point 1 undertaken by Operations Manager

Data/ Parameter	Data Unit	Description	Source of data	Measured (m), calculated (c), or estimated (e)	Recording frequency	Proportion of data to be monitored	Data archiving (electronic / paper)	QA/QC procedures to be applied	Person(s) responsible for:		
									Measurement	Calibration	Verification
$NCV_{f,y}$	GJ/m^3	The net calorific value (energy content) per volume unit of natural gas used in the calculation of project emissions.	Based on fortnightly sampling at the Afam plant gas reception point (point 1 in Figure A4.1)	m	Fortnightly sampling and analysis	100%	Electronic	Gas samples collected using Shell Nigeria standard gas sampling protocol and analysed using standard gas chromatography techniques in on-site laboratory. The calorific value of the gas will be recorded by the project participant and cross-checked against measurements made, and provided, by the gas supplier.	Undertaken fortnightly at Afam plant by Technician and by gas supplier (Okolama gas plant) and	Calibration will be carried out by Technician at both gas supply and plant end.	Verification performed between gas supply and plant readings.
$EF_{CO2,f,y}$	tCO_2/ GJ	CO_2 emission factor per unit of energy of natural gas used in the calculation of project emissions.	Based on fortnightly sampling at the Afam plant gas reception point (point 1 in Figure A4.1)	m	Fortnightly sampling and analysis	100%	Electronic	Gas samples collected using Shell Nigeria standard gas sampling protocol and analysed using standard gas chromatography techniques in on-site laboratory. The CO_2 content of the gas will be recorded by the project participant and cross-checked against measurements made, and provided, by the gas supplier.	Undertaken fortnightly at Afam plant by Technician and by gas supplier (Okolama gas plant) and	Calibration will be carried out by Technician at both gas supply and plant end.	Verification performed between gas supply and plant readings.

Data/ Parameter	Data Unit	Description	Source of data	Measured (m), calculated (c), or estimated (e)	Recording frequency	Proportion of data to be monitored	Data archiving (electronic / paper)	QA/QC procedures to be applied	Person(s) responsible for:		
									Measurement	Calibration	Verification
$EG_{PJ, 5,y}$	MWh	Electricity produced by gas turbines (GT 12 & GT 13)	Electricity meters installed in the plant power export point to bus-bar (meter type EDMI MK6E with accuracy class 0,2S/0,55. IEC62053-22/62052/11)	m	Continuous metering of electricity supplied by the gas turbines to the bus-bar of the Afam plant.	100%	Electronic	Metered export of electricity to be checked against data on power received by the grid operator (PHCN) at the Afam plant-grid interface points, and calibration of meters needs to be undertaken if electrical energy measured by the system differs by over half a percent (0.5%) from any back-up system.	Meter reading to be recorded daily by Operators	Plant Engineer to ensure meters are calibrated at least every 180-days, as outlined in section 7.3 of the PPA)	Main and Check Tariff Meters used for verification by Operator
$EG_{PJ, 6,y}$	MWh	Electricity produced by gas turbine and steam turbine (GT 11 & ST)	Electricity meters installed in the plant power export point to bus-bar (meter type EDMI MK6E with accuracy class 0,2S/0,55. IEC62053-22/62052/11)	m	Continuous metering of electricity supplied by the gas turbine and steam turbine to the bus-bar of the Afam plant.	100%	Electronic	Metered export of electricity to be checked against data on power received by the grid operator (PHCN) at the Afam plant-grid interface points. Accuracy of meters are to be tested every 180 days as outlined in section 7.3 of the PPA and calibration of meters needs to be undertaken if electrical energy measured by the system differs by over half a percent (0.5%) from any back-up system.	Meter reading to be recorded daily by Operators	Plant Engineer to ensure meters are regularly calibrated. See QA/QC procedure.	Main and Check Tariff Meters used for verification by Operator

Data/ Parameter	Data Unit	Description	Source of data	Measured (m), calculated (c), or estimated (e)	Recording frequency	Proportion of data to be monitored	Data archiving (electronic / paper)	QA/QC procedures to be applied	Person(s) responsible for:		
									Measurement	Calibration	Verification
$OXID_f$	-	Oxidation factor of natural gas used in the calculation of project emissions.	2006 IPCC Guidelines for National Greenhouse Gas Inventories	e	Annual	100%	IPCC (2006) guidelines will be kept	N/A	N/A	N/A	N/A

Appendix 6. Summary of post registration changes

The name tags on the project gas turbines ‘GT1, GT2 and GT3’ as shown in figures 4 and A4.1 of the registered PDD are now corrected as GT13, GT12 and GT11 respectively in the revised PDD. Related corrections made in the name tags of the gas turbines under Table A4.1 and Section B.7.1 of the revised PDD.

In the actual implementation of the project activity, the connections of the meters to the electrical generators were slightly modified. The electricity produced from GT 11 and Steam turbine generators are metered from point (6) while electricity produced from GT 12 and GT 13 generators are metered from point (5). In line with Project Standard, version 07, Appendix 1, paragraph 6, this is the case of change of connection of meter(s). This modification does not have any impact on the emission reductions; the electricity generated used in the baseline emission estimation is the summation of electricity generated from all the turbines. The monitoring points remain unchanged from that registered in the PDD.

The name tag of the natural gas flow metering point at the turbine #13 inlet has been corrected to make consistent with Table A4.1 of the PDD.

Also, due to the format of the version 05 PDD form in VVS template, table 2 of the original PDD in VVM template is no longer applicable and hence the re-numbering of the tables in the revised PDD.

Annex 1 has modified the Project participant contact point details and added the information on the entities involved for determination of baseline and preparation of the PDD as per the requirement of VVS track PDD completion guideline.

The typographical error in Figure and Table heading numbering under Appendix 5 and throughout in the PDD are corrected as A4.1.

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Document information

Version	*Date*	*Description*
05.0	25 June 2014	Revisions to: • Include the Attachment: Instructions for filling out the project design document form for CDM project activities (these instructions supersede the "Guidelines for completing the project design document form" (Version 01.0)); • Include provisions related to standardized baselines; • Add contact information on a responsible person(s)/ entity(ies) for the application of the methodology (ies) to the project activity in B.7.4 and Appendix 1; • Change the reference number from *F-CDM-PDD* to *CDM-PDD-FORM;* • Editorial improvement.
04.1	11 April 2012	Editorial revision to change version 02 line in history box from Annex 06 to Annex 06b
04.0	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).
03.0	26 July 2006	EB 25, Annex 15
02.0	14 June 2004	EB 14, Annex 06b
01.0	03 August 2002	EB 05, Paragraph 12 Initial adoption.

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