Approved baseline and monitoring methodology AM0009

"Recovery and utilization of gas from oil wells that would otherwise be flared or vented"

I. SOURCE, DEFINITIONS AND APPLICABILITY

Sources

This baseline and monitoring methodology is based on elements from the following proposed methodologies:

- NM0026 "Rang Dong Oil Field Associated Gas Recovery and Utilization Project" prepared by Japan Vietnam Petroleum Co. Ltd;
- NM0227 "Recovery of methane from on- and off-shore oil fields that otherwise will be vented into the atmosphere" prepared by SOCAR in collaboration with ICF International.

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

- "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion";
- "Tool to calculate baseline, project and/or leakage emissions from electricity consumption";
- "Tool for the demonstration and assessment of additionality";
- "Assessment of the validity of the original/current baseline and to update of the baseline at the renewal of the crediting period".

For more information regarding the proposed new methodologies and the tools as well as their consideration by the Executive Board (hereinafter referred to as the Board) of the clean development mechanism (CDM) please refer to <http://cdm.unfccc.int/goto/MPappmeth>.

Selected approach from paragraph 48 of the CDM modalities and procedures

"Existing actual or historical emissions, as applicable".

and

"Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment".

Definitions

For the purpose of this methodology, the following definitions apply:

Associated gas. Natural gas found in association with oil, either dissolved in the oil or as a cap of free gas above the oil.

Gas-lift. An artificial lift method for oil wells exploitation in which gas is injected into the production tubing to reduce the hydrostatic pressure of the fluid column. The resulting reduction in bottomhole pressure allows the reservoir liquids to enter the wellbore at a higher flow rate.

Gas-lift gas. High-pressure gas used for gas-lift in the oil wells.

Recovered gas. The associated gas and/or gas-lift gas recovered from the project oil wells.

Processing plant. A facility designed to separate or process hydrocarbons through chemical, physical or physical-chemical procedures in order to produce marketable hydrocarbon and other (e.g. sulphur) products.

Compressed Natural Gas (CNG). The processed gas that has been compressed to high pressure (typically > 200 bar) for the purpose of storage and/or transportation.

Gas pipeline. The pipeline with capacity to transport more than 1 million Nm^3 of gas per day.

Applicability

The methodology is applicable to project activities that recover and utilise associated gas and/or gas-lift gas from oil wells.

The methodology is applicable under the following conditions:

- Under the project activity the recovered gas, after the pre-treatment (compression and phase separation) in movable or stationary equipment, is:
    - Consumed on-site to meet energy demands; and/or
    - Transported to a gas pipeline without prior processing; and/or
    - Transported to a processing plant where it is processed into hydrocarbon products (e.g. dry gas, liquefied petroleum gas (LPG) and condensates). The dry gas is either: (i) transported to a gas pipeline directly; or (ii) compressed to CNG first, then transported by trailers/trucks/carriers and then decompressed again, before it finally enters the gas pipeline;
- The project activity does not lead to changes in the process of oil production, such as an increase in the quantity or quality of oil extracted, in the oil-wells within the project boundaries;
- The injection of any gases into the oil reservoir and its production system is allowed in the project activity only for the purpose of the gas-lift process;
- All recovered gas comes from oil wells that are in operation and are producing oil at the time of the recovery of the associated gas and/or gas-lift gas.

In addition, the applicability conditions included in the tools referred to above apply.

Finally, the methodology is only applicable if the identified baseline scenario is:

- The continuation of the current practice of either venting (scenario G1), flaring (scenario G2) of the associated gas and/or gas-lift gas or on-site use of the partial amount of associated gas and/or gas-lift gas to meet on-site energy demands and rest of the gas are either vented or flared (scenario G3); and
- The continued operation of the existing oil and gas infrastructure without any other significant changes (scenario P4); and
- In the case where gas-lift is used under the project activity: the gas-lift gas under the baseline

uses the same source as under the project activity and the same quantity as under the project activity (Scenario 01).

II. BASELINE METHODOLOGY PROCEDURE

Project boundary

The project boundary encompasses:

- The project oil reservoir and oil wells where the associated gas and/or gas-lift gas is collected;
- The site where the associated gas and/or gas-lift gas was flared or vented in the absence of the project activity;
- The gas recovery, pre-treatment, transportation infrastructure, including where applicable, compressors;
- The source of gas-lift gas.

The greenhouse gases included in or excluded from the project boundary are shown in **Table 1**.

Table 1: Emissions sources included in or excluded from the project boundary

	Source	Gas	Included?	Justification/Explanation
Baseline	Combustion of fossil fuels at end-users that are produced from non-associated gas or other fossil sources	CO_2	Yes	Main source of emissions in the baseline
		CH_4	No	Excluded for simplification. This is conservative
		N_2O	No	Excluded for simplification. This is conservative
Project Activity	Energy use for the recovery, pre-treatment, transportation, and if applicable, compression/decompression, transportation of the recovered gas	CO_2	Yes	Main source of emissions in the project
		CH_4	No	Excluded for simplification. This emission source is assumed negligible
		N_2O	No	Excluded for simplification. This emission source is assumed negligible

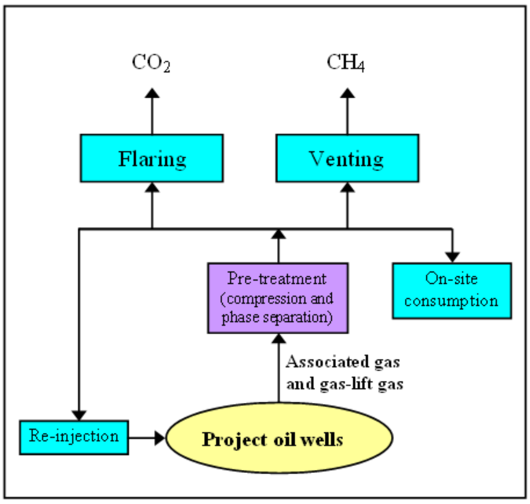

Figure 1: Schematic illustration of the baseline activity

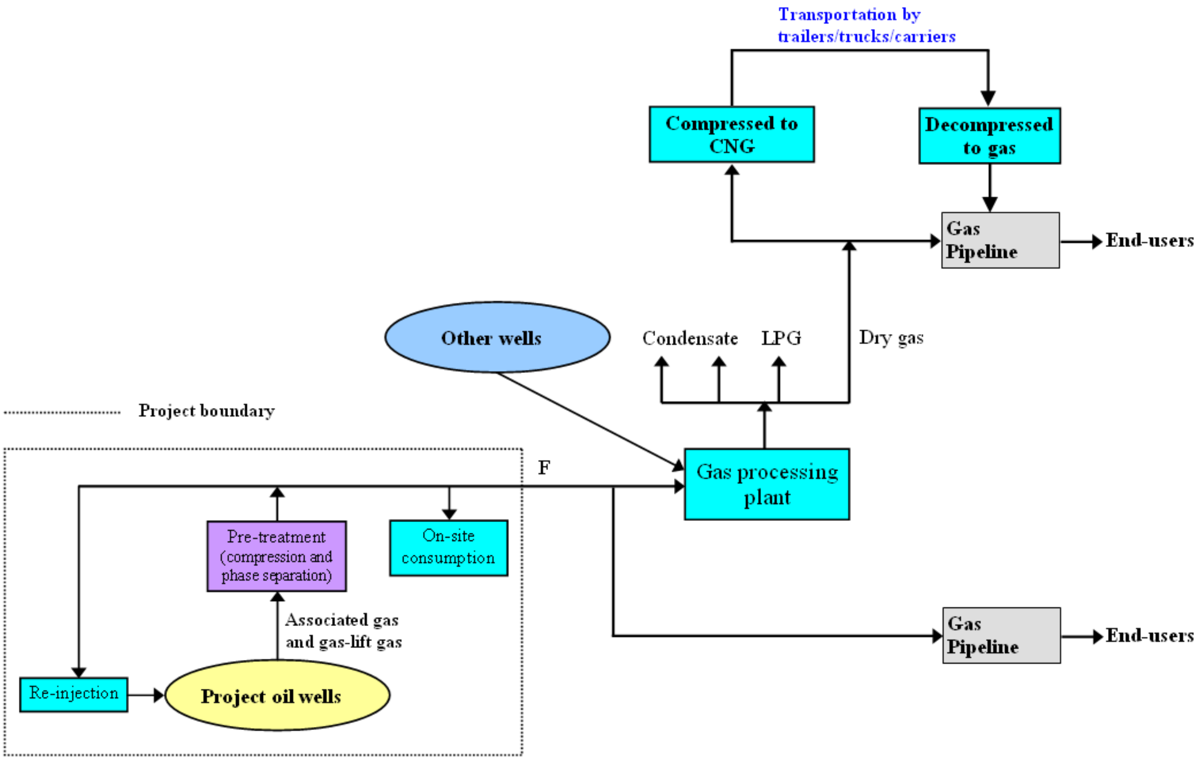

Figure 2: Schematic illustration of the project activity

The project area may encompass several wells under a production sharing contract (PSC) with a production target.

Identification of the baseline scenario and demonstration of additionality

Project participants shall apply the following procedure:

Step 1: Identify plausible alternative scenarios

The project activity involves three components. Plausible alternative scenarios should include alternatives for the following components:

Plausible alternative baseline scenarios for the associated gas and/or gas-lift gas from the project oil wells could include, inter alia:

G1: Release of the associated gas and/or gas-lift gas into the atmosphere at the oil production site (venting);

G2: Flaring of the associated gas and/or gas-lift gas at the oil production site;

G3: On-site use of the partial amount of associated gas and/or gas-lift gas to meet on-site energy and rest of the gas are either vented (G1) or flared (G2);

G4: Injection of the associated gas and/or gas-lift gas into an oil or gas reservoir;

G5: The proposed project activity without being registered as a CDM project activity;

G6: Recovery, transportation and utilization of the associated gas and/or gas-lift gas as feedstock for manufacturing of useful products.

Plausible alternative baseline scenarios for oil and gas infrastructure should include the proposed project activity and all relevant scenarios for any existing or new gas processing plants, pipelines, compressors, etc. They depend heavily on the context of the proposed project, but could include, inter alia:

P1: Construction of a processing plant for the purpose of processing the recovered gas, in the same way as in the project activity, without being registered as a CDM project activity;

P2: Construction of a processing plant of a lower capacity than under the project activity, which processes only non-associated gas and does not process recovered gas;

P3: Supplying recovered gas to an existing gas processing plant and constructing the necessary infrastructure, without being registered as a CDM project activity;

P4: Continuation of the operation of the existing oil and gas infrastructure without any other significant changes;

P5: Supplying recovered gas to a gas pipeline without prior processing and without being registered as a CDM project activity.

Plausible alternative baseline scenarios for the use of gas-lift could include, inter alia:

O1: Gas from the same source as under the project activity and in the same quantity as under the project activity is used for the gas-lift system;

O2: Gas from a different source than under the project activity but using the same quantity of gas-lift gas as under the project activity is used for the gas-lift system;

O3: Gas from the same source as under the project activity, but using a different quantity of gas-lift gas, is used for the gas-lift system;

O4: Gas from a different source than under the project activity and in a different quantity than under the project activity, is used for the gas-lift system;

O5: No gas-lift system is utilized.

Realistic combinations of these three components should be identified and considered as possible alternative scenarios to the proposed project activity. The identified combinations should be transparently described and be illustrated in schematic diagrams in the CDM-PDD.

Step 2: Evaluate legal aspects

In evaluating legal aspects, the following issues should be addressed:

- Are the alternatives permitted by law or other (industrial) agreements and standards?
- Are there laws or other regulations (e.g. environmental regulations) which implicitly restrict certain alternatives?

All baseline alternatives shall be in compliance with all applicable legal and regulatory requirements, even if these laws have objectives other than GHG reductions. If an alternative does not comply with all applicable legislation and regulations, such an alternative should be eliminated unless it is demonstrated, based on an examination of current practice in the country or region in which the law or regulation applies, that applicable legal or regulatory requirements are systematically not enforced and that non-compliance is widespread.

Step 3: Evaluate the economic attractiveness of alternatives

The economic attractiveness is assessed for those alternative scenarios that are feasible in technical terms and that are identified as permitted by law or other (industrial) agreements and standards in Step 2. The economic attractiveness is assessed by determining an expected Internal Rate of Return (IRR) of each alternative scenario, following the guidance for the investment analysis in the latest approved version of the "Tool for the demonstration and assessment of additionality". The IRR should be determined using, inter alia, the following parameters as applicable to the relevant scenario:

- Overall projected production of associated gas and/or gas-lift gas;
- The projected quantity of gas recovered, gas flared, vented, consumed on-site, processed in a gas processing plant and/or compressed into a pipeline;
- The agreed price for the delivery of recovered gas (e.g. from a Production Sharing Contract) to the gas pipeline or gas processing plant (if operated by a third party);
- The net calorific value of the recovered gas;
- Capital expenditure for all oil and gas infrastructure needed in the relevant scenario, such as gas recovery facilities, pipelines, and gas processing plant (if applicable) etc. (CAPEX);
- All operational expenditure associated with the respective scenario (OPEX);
- All revenues from the operation of the alternative scenario, such as revenues from selling processed gas or other products of the gas processing plant or electricity;
- Any profit sharing agreements and cost recovery, such as cost savings through the substitution of products by the recovered gas, if applicable.

If venting or flaring of the associated gas at a given location is not outright banned, but instead is subject to taxes or fines, the impact of these taxes and fines should be considered in the IRR calculation.

The alternative scenario that is economically the most attractive course of action is considered as the baseline scenario. Proceed to the next step if the IRR of the project activity is lower than the hurdle rate of the project participants (typically about 10%) and if the most plausible baseline scenario is not the project activity without being registered as a CDM project activity; otherwise, the project activity is not additional.

The DOE should verify what value for the IRR is typical for this type of investment in the respective Host country. The calculations should be described and documented transparently.

Step 4: Common practice analysis

Apply the “common practice analysis”, following the guidance for the common practice analysis in the latest approved version of the “Tool for the demonstration and assessment of additionality”.

Baseline emissions

Project activities under this methodology reduce emissions by recovering associated gas and/or gas-lift gas and utilizing the recovered gas. The utilization of the recovered gas displaces the use of other fossil fuel sources. For example:

- The use of recovered gas in a processing plant can displace the use of non-associated gas in that processing plant;
- In another situation, the recovered gas may be compressed into a natural gas pipeline, thereby displacing the processing of non-associated gas in a gas processing plant at another site.

The exact emission effects are difficult to determine and would require an analysis of the whole fuel supply chain up to the end-users for both the project activity and the baseline scenario. This methodology provides a simplified and conservative calculation of emission reductions, assuming that the use of recovered gas displaces the use of methane – the fossil fuel with the lowest direct CO_2 emissions. Emissions from processing and transportation of fuels to end-users are neglected for both the project activity and the baseline scenario, as it is assumed that these emissions are similar in their magnitude and level out.

Baseline emissions are calculated as follows:

$$BE_y = V_{F,y} \cdot NCV_{RG,F,y} \cdot EF_{CO2,Methane} \quad \textbf{(1)}$$

Where:

BE_y	=	Baseline emissions in year y, (tCO_2e)
$V_{F,y}$	=	Volume of total recovered gas measured at point F in Figure 2 in year y (Nm^3)
$NCV_{RG,F,y}$	=	Average net calorific value of recovered gas at point F in Figure 2 in year y (TJ/Nm^3)
$EF_{CO2,Methane}$	=	CO_2 emission factor for methane (tCO_2/TJ)

Project emissions

The following sources[1] of project emissions are accounted in this methodology:

- CO_2 emissions due to consumption of fossil fuels for the recovery, pre-treatment, transportation, and, if applicable, compression of the recovered gas up to the point *F* in Figure 2;
- CO_2 emissions due to the use of electricity for the recovery, pre-treatment, transportation, and, if applicable, compression of the recovered gas up to the point *F* in Figure 2.

Project emissions are calculated as follows:

$$PE_y = PE_{CO2,fossilfuels,y} + PE_{CO2,elec,y} \tag{2}$$

Where:

PE_y	=	Project emissions in year *y,* (tCO_2e)
$PE_{CO2,fossilfuels,y}$	=	CO_2 emissions due to consumption of fossil fuels for the recovery, pre-treatment, transportation, and, if applicable, compression of the recovered gas up to the point *F* in Figure 2 in year *y* (tCO_2e)
$PE_{CO2,elec,y}$	=	CO_2 emissions due to the use of electricity for recovery, pre-treatment, transportation and, if applicable, compression of the recovered gas up to the point *F* in Figure 2 in year *y,* (tCO_2e)

<u>Project emissions from the consumption of fossil fuels</u>

Project emissions $PE_{CO2,fossilfuels,y}$ due to the consumption of fossil fuels, including the recovered gas, if applicable for the recovery, pre-treatment, transportation and, if applicable, compression of the recovered gas are calculated applying the latest approved version of the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion" where $PE_{CO2,fossilfuels,y}$ corresponds to $PE_{FC,j,y}$ in the tool and process j corresponds to all sources of fuel combustion (e.g. a compressor, etc) up to point *F* in Figure 2. All applicable emission sources should be documented transparently in the CDM-PDD and in monitoring reports.

<u>Project emissions from consumption of electricity</u>

Project emissions $PE_{CO2,elec,y}$ due to the use of electricity for the recovery, pre-treatment, transportation, and, if applicable, compression of the recovered gas are calculated applying the latest approved version of the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption" where $PE_{CO2,elec,y}$ corresponds to $PE_{EC,y}$ in the tool and the electricity consumption sources *j* in the tool corresponds to all sources of electricity consumption (e.g. a compressor, etc) up to point *F* in Figure 2. All applicable sources of electricity consumption should be documented transparently in the CDM-PDD and in monitoring reports.

[1] Other sources of project emissions such as emissions from leaks, venting and flaring during the recovery, transportation and processing of recovered gas are assumed to be of similar magnitude in the baseline scenario.

Leakage

Leakage emissions shall be accounted for project activities where the recovered gas is transported to a processing plant where it is processed into hydrocarbon products (e.g. dry gas, LPG and condensates) and the dry gas is compressed to CNG first, then transported by trailers/trucks/carriers and then decompressed again, before it finally enters the gas pipeline. For other types of project activities, leakage emissions need not to be considered.

Leakage emission is calculated as follows:

$$LE_y = LE_{FC,y} + LE_{EC,y} \tag{3}$$

Where:

LE_y	=	Leakage emissions in year *y* (tCO_2e)
$LE_{FC,y}$	=	Leakage emissions due to fossil fuel consumption after point *F* in Figure 2 in year *y* (tCO_2e)
$LE_{EC,y}$	=	Leakage emissions due to electricity consumption after point *F* in Figure 2 in year *y* (tCO_2e)

Leakage emissions due to fossil fuel consumption

Leakage emissions due to fossil fuel consumption in year y ($LE_{FC,y}$) is calculated applying the latest approved version of the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion" where $LE_{FC,y}$ corresponds to $PE_{FC,j,y}$ in the tool and process *j* corresponds to all sources of fuel combustion (e.g. compressor, decompressor or trailers/trucks/carriers etc) after point *F* in Figure 2. All emission sources of fuel consumptions should be documented transparently in the CDM-PDD and in monitoring reports.

Leakage emissions due to electricity consumption

Leakage emissions due to electricity consumption in year *y* ($LE_{EC,y}$) is calculated applying the latest approved version of the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption" where $LE_{EC,y}$ corresponds to $PE_{EC,y}$ in the tool and the electricity consumption sources *j* in the tool corresponds to all sources of electricity consumption (e.g. compressor, decompressor or trailers/trucks/carriers etc) after point *F* in Figure 2. All emission sources of electricity consumption should be documented transparently in the CDM-PDD and in monitoring reports.

Emission reductions

Emission reductions are calculated as follows:

$$ER_y = BE_y - PE_y - LE_y \tag{4}$$

Where:

ER_y	=	Emission reductions in year y (tCO_2e)
BE_y	=	Baseline emissions in year y (tCO_2e)
PE_y	=	Project emissions in year y (tCO_2e)
LE_y	=	Leakage emissions in year y (tCO_2e)

Changes required for methodology implementation in 2nd and 3rd crediting periods

Refer to the tool "Assessment of the validity of the original/current baseline and to update of the baseline at the renewal of the crediting period".

Project activity under a programme of activities (PoA)

In addition to the requirements set out in the latest approved version of the "Standard for demonstration of additionality, development of eligibility criteria and application of multiple methodologies for programme of activities", the following shall be applied for the use of this methodology in a project activity under a programme of activities (PoAs).

The PoA may consist of one or several types of CPAs. CPAs are regarded to be of the same type if they are similar with regard to the demonstration of additionality, emission reduction calculations and monitoring. The CME shall describe in the CDM-PoA-DD for each type of CPAs separately:

(a) Eligibility criteria for CPA inclusion used for each type of CPAs. In case of combination of the types of use of the recovered gas in one CPA, the eligibility criteria shall be defined for each type of use of the recovered gas, separately;

(b) Emission reduction calculations for each type of CPAs;

(c) Monitoring provisions for each type of CPAs.

The CME shall describe transparently and justify in the CDM-PoA-DD which CPAs are regarded to be of the same type. CPAs are not regarded to be of the same type, if one of the following conditions is different:

(a) The baseline scenario with regard to any of the following aspects:

  (i) On-site use of the partial amount of associated gas and/or gas-lift gas to meet on-site energy and the rest of the gas are either vented or flared;

  (ii) In case of different types of products, recovery, transportation and utilization of the associated gas and/or gas-lift gas as feedstock for manufacturing of useful products;

(b) The project activity with regard to any of the following aspects of the use of the recovered gas:

  (i) Consumed on-site to meet energy demands;

  (ii) Transported to a gas pipeline without prior processing;

  (iii) Transported to a processing plant where it is processed into hydrocarbon products (e.g. dry gas, LPG and condensates). The dry gas is either:

- Transported to a gas pipeline directly, or
- Compressed to CNG first, then transported by trailers/trucks/carriers and then decompressed again, before it finally enters the gas pipeline.

(iv) Combination of any above.

When defining eligibility criteria for CPA inclusion for a distinct type of CPAs, the CME shall consider relevant technical and economic parameters, such as:

(a) Ranges of overall projected production of associated gas and/or gas-lift gas;

(b) Ranges of projected quantity of gas recovered, gas flared, vented, consumed on-site, processed in a gas processing plant and/or compressed into a pipeline;

(c) Ranges of price for the delivery of recovered gas;

(d) Ranges of net calorific value of the recovered gas;

(e) Ranges of capital expenditure for gas infrastructure needed in the relevant scenario, such as gas recovery facilities, pipelines, and gas processing plant (if applicable) etc.;

(f) Ranges of operational expenditure;

(g) Ranges of revenues from the operation of the alternative scenario, such as revenues from selling processed gas or other products of the gas processing plant or electricity.

The eligibility criteria related to costs, revenues and investment climate shall be updated every two years in order to correctly reflect the technical and market circumstances of a CPA implementation.

In case the PoA contains several types of CPAs, the actual CPA-DD submitted for the purpose of registration of the PoA shall contain all information required as per the latest approved version of the “Guidelines for completing the component project activity design document form” for each type of actual CPA, to be validated by a DOE and submitted for the registration to the Board.

Data and parameters not monitored

In addition to the parameters listed in the tables below, the provisions on data and parameters not monitored in the tools referred to in this methodology apply.

Data / Parameter:	$EF_{CO2,Methane}$
Data unit:	tCO_2/TJ
Description:	CO_2 emission factor for methane
Source of data:	Calculated in line with procedures and data presented in ISO 6976:
	Unit | **Value** | **Source**
	Carbon Content of Methane | 12,011 kg/kmol | ISO 6976: Table 1
	CO_2 Emission Factor for Methane | 44.01 kg/kmol | ISO 6976: Table 1
	NCV of Methane (at 25^0C) | 802.60 kJ/mol | ISO 6976: Table 3
Value to be applied:	54.834 tCO_2/TJ
Any comment:	---

III. MONITORING METHODOLOGY

All data collected as part of monitoring should be archived electronically and be kept at least for two years after the end of the last crediting period. One hundred per cent of the data should be monitored if not indicated otherwise in the tables below. All measurements should be conducted with calibrated measurement equipment according to relevant industry standards.

The CDM-PDD will have to include minimal procedures to ensure that the data collection and retention will be made properly.

In addition, the monitoring provisions in the tools referred to in this methodology apply.

Projection and adjustment of project and baseline emissions on the basis of oil production

Project as well as baseline emissions depend on the quantity of associated gas and gas-lift gas recovered, which is linked to the oil production. Oil production may be projected with the help of a reservoir simulator, reflecting the rock and fluid properties in the oil reservoir. As projections of the oil production, the methane content of the gas and other parameters involve a considerable degree of uncertainty, the quantity and composition of the recovered gas are monitored ex post and baseline and project emissions are adjusted respectively during monitoring.

The validating DOE shall confirm that estimated emission reductions reported in the CDM-PDD are based on estimates provided in the survey used for defining the terms of the underlying oil production project as per the production sharing contract.

At verification the verifying DOE shall check the production data for oil and associated gas and gas-lift gas and compare them with the initial production target as per the information provided in survey used for defining the terms of the underlying oil production project.

If the oil production differs significantly from the initial production target, then it should be checked that this is not intentional, and that such a scenario is properly addressed by the production sharing contract between the contracted party(ies).

Data and parameters monitored

Data / Parameter:	$V_{F,y}$
Data unit:	Nm^3
Description:	Volume of the total recovered gas measured at point *F* in Figure 2 in year *y*
Source of data:	Flow meter (e.g. diaphragm gouge)
Measurement procedures (if any):	Data should be measured using calibrated flow meters. Measurements should be taken at the point(s) where recovered gas exits the pre-treatment plant
Monitoring frequency:	Continuously
QA/QC procedures:	Volume of gas should be completely metered with regular calibration of metering equipment. The measured volume should be converted to the volume at normal temperature and pressure using the temperature and pressure at the time to measurement
Any comment:	---

Data / Parameter:	$NCV_{RG,F,y}$
Data unit:	TJ/Nm^3
Description:	Average net calorific value of recovered gas at point *F* in Figure 2 in year *y*
Source of data:	On site measurement (Chemical analysis of gas samples taken at point *F* in Figure 2)
Measurement procedures (if any):	Measurements should be undertaken in line with national or international fuel standards. Gas samples should regularly be taken at point *F* in Figure 2 and the molar composition of each gas sample should be determined through chemical analysis following the procedures for QA/QC. Based on the molar composition, the Net Calorific Value on a volumetric basis should be determined for each sample in line with ISO 6976 or an equivalent standard for a combustion reference temperature of 25^0C and the same metering reference condition used for parameter VF,y. The average NCV during the period y is defined as the arithmetic average of NCVs for the samples taken during the same period
Monitoring frequency:	Sampling and compositional analysis and calculation of net calorific value at least monthly
QA/QC procedures:	Sampling in accordance with ISO 10715 or equivalent standard. Compositional analysis in accordance with ISO 6974 or equivalent standard. Routine maintenance and calibration in accordance with ISO 10723 or equivalent standard. GC calibration gases certified to ISO 6141 or equivalent standard. Annual manufacturer servicing and calibration to ISO17025 or equivalent standard. In case third party laboratories are used, these should as a minimum have ISO17025 accreditation or justify that they can comply with similar quality standards
Any comment:	For the purpose of this methodology, the qualifier “net” is synonymous with “lower” and “inferior”, and the term “calorific value” is synonymous with “heating value”

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History of the document

Version	Date	Nature of revision(s)
06.0.0	20 July 2012	EB 68, Annex 7 Revision to: • Clarify that the leakage emissions shall only be accounted for in project activities where the recovered gas is transported to a processing plant where it is processed into hydrocarbon products (e.g. dry gas, LPG and condensates) and where the dry gas is compressed to CNG, transported by trailers/trucks/carriers and then decompressed again, before it finally enters the gas pipeline; and • Introduce provisions for the use of this methodology in a project activity under a PoA.

05.0.1	EB 66, Annex 41 2 March 2012	Editorial amendment to: • Correct the reference of common practice analysis; • Correct the description of $V_{F,y}$ and description of point F in Figure 2 throughout the methodology; and • Update the title of the methodological tool “Assessment of the validity of the original/current baseline and to update of the baseline at the renewal of the crediting period”.
05.0.0	EB 65, Annex 11 25 November 2011	Revision to expand the applicability of the methodology to situations where: • The associated gas and/or gas-lift gas is partially recovered and utilized on-site before the implementation of the project activity; • Pre-treatment is done by movable or stationary equipments; • Recovered gas is first compressed to Compressed Natural Gas (CNG), then transported via trailers or carriers, and later decompressed and gasified before it finally enters the gas pipelines to end-users; Additionally, revision to: • Provide definition of CNG and gas pipeline; • Include leakage emissions due to the use of fossil fuels and/or electricity due to the compression, transportation and decompression of CNG; • Update the schematic illustration of baseline and project activity to reflect above changes; • Update the monitoring tables by revising (i) the CO_2 emission factor for methane, and (ii) the measurement procedures and QA/QC procedures for net calorific value of recovered gas; and • Remove reference to the “Combined tool to identify the baseline scenario and demonstrate additionality”; • Add reference to the tool “Validity of the original/current baseline and to update the baseline at the renewal of a crediting period”.
04	EB 46, Annex 5 25 March 2009	Revision to: • Expand the scope of the methodology by allowing the use of gas coming to the surface from gas-lift systems; • Modify the project activity diagram; • Adjust the table for emission sources in the project boundary section; • Include provisions to identify plausible alternative baseline scenarios for a gas processing facility and gas-lift gas; • Simplify the procedure to calculate baseline emissions; • Neglect project emissions related to gas leaks, venting and flaring during the recovery, transport and processing of the recovered gas; • Eliminate the leakage emissions section; and • Eliminate the uncertainty assessment section.
03.3	EB 44, Annex 6 28 November 2008	Editorial revision to delete the term ‘transportation’ from the section “CH_4 project emissions from venting, leak or flaring of the associated gas”.
03.2	EB 42, Annex 4 26 September 2008	Editorial revision to correct equation 3 under project emissions.
03.1	EB 39, Paragraph 22 16 May 2008	“Tool to calculate baseline, project and/or leakage emissions from electricity consumption” replaces the withdrawn “Tool to calculate project emissions from electricity consumption”.

03	EB 36, Annex 6 30 November 2007	Revision to: • Expand the applicability of the methodology by introducing a new baseline scenario where the associated gas is vented in the absence of the project activity; • Introduce an option of supplying part of the captured gas directly to the existing natural gas grid without processing; • Introduce project emissions from the use of electricity and fossil fuels for project activities where electricity and fossil fuels are used for capture, transportation and processing of the associated gas; • Incorporate “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion”, “Tool to calculate project emissions from electricity consumption” and “Combined tool to identify the baseline scenario and demonstrate additionality”.
02.1	22 June 2007	The methodology was editorially revised to add the guidance provided by the Board at its thirty-second meeting (paragraph 23 of thirty-second meeting report) in the following sections: (i) Projection and adjustment of project and baseline emissions; and (ii) Note below the QA/QC table (on Page 15). Guidance by the Board: “The Board clarified that the validating DOE shall confirm that estimated flare reduction in the CDM-PDD for project activities using approved methodology AM0009 are based on estimates provided in the survey used for defining the terms of the underlying oil production project. At verification the DOE shall check the production data for oil and associate gas and compare it with initial production target. If the oil production differs significantly from initial production target, then it should be checked upon verification that this is not intentional, and that such a scenario is properly addressed by the contract between the contracted party(ies).”
02	EB 19, Annex 5 13 May 2005	Revision to introduce project emissions from the transportation of the associated gas and project emissions from accidents.
01	EB 13, Annex 3 26 March 2004	Initial adoption.
Decision Class: Regulatory **Document Type**: Standard **Business Function**: Methodology		