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

CONTENTS

Annexes

SECTION A. General description of project activity

A.1. Title of the project activity:

Capture and processing low pressure associated gas from the Neft Dashlari and Palchiq Pilpilassi oil fields of SOCAR

Table A1: CDM PDD Version Number	
Version 1.01	30th October 2009
Version 1.02	4th October 2010
Version 1.03	2nd February 2011
Version 1.04	23rd March 2011
Version 1.05	14th April 2011
Version 1.06	5th October 2011
Version 1.07	7th December 2011
Version 1.08	10th July J2012
Version 1.09	26th December 2012

A.2. Description of the project activity:

Purpose of the CDM Project. The purpose of the proposed CDM project activity is to reduce venting of the low pressure associated gas at the Neft Dashlari and Palchiq Pilpilassi oil fields of the Oil and Gas Production Department (OGPD) Neft Dashlari of SOCAR. The recovered low-pressure associated gas will be collected, compressed and transported to the existing gas processing plant (GPP). The GPP receives natural gas and associated gas which are mixed prior to processing. From the mix of associated and natural gas the following products are generated:

- Dry Natural Gas
- Liquefied Petroleum Gas
- Unstable Gasoline/Gas Condensate for internal use at the plant. This is called unstable, as the share of liquids may change over time.

The GPP does not produce any Compressed Natural Gas (CNG). After processing, the dry natural gas is fed into a pipeline connecting the district of Qez with the Absheron Magistral Gas Pipeline. Customers using these products are general population and industrial enterprises.

Associated petroleum gas is a by-product of the petroleum industry obtained by a purification process in which it is separated from oil. In many oil producing countries around the world associated gas is not utilized but either flared or vented to the atmosphere instead. The harmful effect of associated gas on the atmosphere is significant if vented since the methane contained is a strong greenhouse gas (GWP_{100} 21). The proposed project aims to reduce venting of low-pressure associated gas, which is further referred to as low pressure associated gas (LP APG) and recovered gas.

Existing Situation. OGPD Neft Dashlari (to English Oil Rocks) is a unique oil production unit, which construction started 45 km offshore in the Caspian Sea after 1947. Oil exploration began at OGPD Neft Dashlari in 1949, when the first well was drilled. For the purpose of continuous production a small town Neft Dashlari was built in the sea for technical staff of OGPD. The production department operates two offshore oil fields: Neft Dashlari and Palchiq Pilpilassi. The offshore oil platforms are connected by streets and pipelines of about 200 km. Following traditional oil recovery techniques applied at Neft Dashlari and Palchiq Pilpilassi oil fields crude-oil emulsion - the mixture of crude oil, water and associated gas - is transported from oil wells to collector platforms. At these collector platforms recovered

oil quantities are measured and low- pressure (0.08- 0.2 MPa) associated gas is separated from crude oil. The recovered low-pressure associated gas is vented directly at the collector platform in absence of the project activity. The remaining crude-oil emulsion is further transported to oil processing units (OPU) and central processing facilities (CPF) for further separation. At OPU and CPF crude-oil emulsion goes through several separation stages. At the separators the associated gas is collected and compressed up to approx 0.5MPa which enables its transportation to the central hub.

The OPU and each CPF is connected by gathering gas pipelines to the central hub of OGPD. Gas recovered at OPU and CPF is delivered to the central hub for its on-site utilization, whereas low-pressure gas is vented at collector platforms. In absence of the proposed project activity the existing practice will be further applied. Hence, the low-pressure associated gas will be vented at offshore platforms. The scenario existing prior to the start of the proposed project activity is the same as the identified baseline scenario, as described in Section B.4.

Project Scenario: Scope of Activities and Measures. The proposed CDM project activity will recover low-pressure associated gas, which is currently vented. The project will install compressors at the collector platforms and construct connecting pipelines to the gathering gas pipeline. The recovered low-pressure associated gas will be compressed to approx. 0.5 MPa and transported to the central compressor facility KS-3 at the central hub for transportation to an onshore gas processing plant. At the gas processing plant, the recovered gas is processed to dry gas, fed into the pipeline, and into LPG. There is no production of CNG. The recovered gas will thus displace other fossil fuels at end-consumers.

Contribution to Sustainable Development. Through utilization of currently vented associated petroleum gas, which is a valuable energy source, the project will contribute to sustainable development of Azerbaijan. The project avoids utilization of other fossil fuels and thus reduces the emissions also other than greenhouse gases that would occur during the combustion of the same fossil fuels at end-users. In practice venting of APG causes larger emissions, than assumed under the applied baseline methodology, due to emissions of harmful gas methane. Direct positive environmental effects are thus even higher after implementation of the project. The project will create new jobs for operators of compressor facilities and measuring devices, and will contribute to the capacity building of SOCAR's personnel. In particular, the Environmental Division of SOCAR will actively participate in the monitoring and verification process obtaining additional technical know-how, which might be required in further projects. The technologies and equipment to be employed by the project are manufactured by Azerbaijani engineering companies. Thus, the proposed project activity will strengthen Azerbaijani mechanical industry and foster development of applicable technical innovations.

A.3. Project participants:

Name of Party involved (*) (host) indicates a Host Party)	Private and/or public entity(ies) project participants (*) (as applicable)	Paty involved wishes to be considered as project participant (Yes/No)
Azerbaijan (host)	**SOCAR – State Oil Company of Azerbaijan Republic (Public company)**	**No**
Germany	**GAZPROM Germania GmbH (Private entity)**	**No**

SOCAR – State Oil Company of Azerbaijan Republic is the operator of the proposed project activity. SOCAR is a public oil and gas exploration and processing company. The proposed CDM project activity will be implemented on the sites under control and responsibility of SOCAR. GAZPROM Germania GmbH is a German private company and a developer of the proposed project.

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

The proposed project activity is located in the Republic of Azerbaijan, in particular at offshore oil platforms in the Caspian Sea.

Figure A.4.1.1: Map of Azerbaijan[1]

A.4.1.1. Host Party(ies):

The Host Party is the Republic of Azerbaijan.

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

Absheron Pensinsula

A.4.1.3. City/Town/Community etc.:

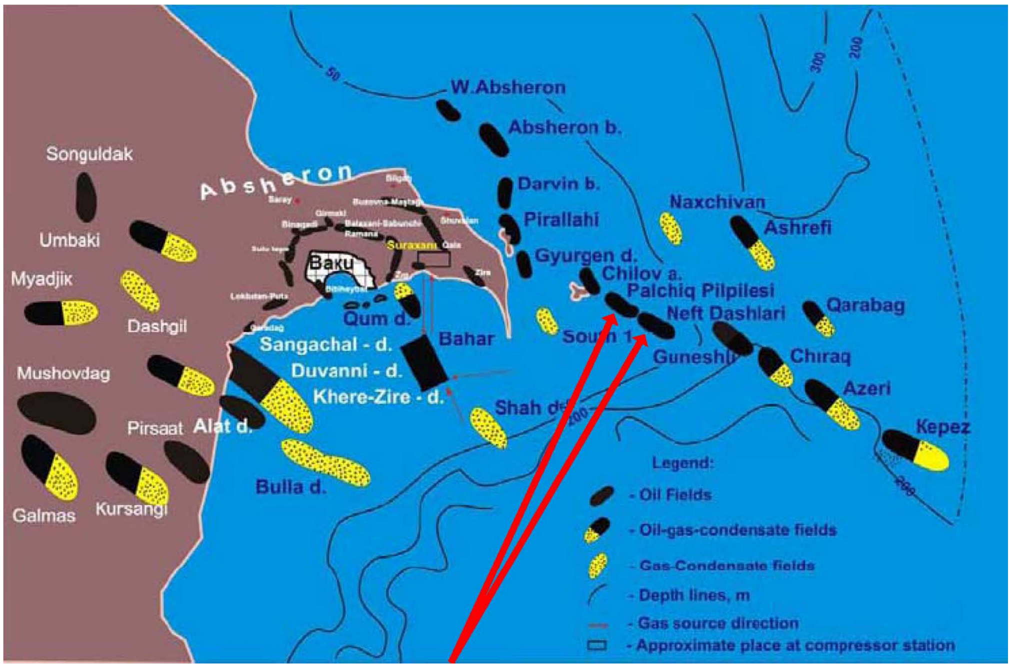
Baku, Azerbaijan

[1] Source: Wikipedia

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

The proposed CDM project activity will be implemented at oil collector platforms of Neft Dashlari and Palchiq Pilpilassi oil fields. These oil fields are shown on Figure below (see arrows).

Figure A.4.1.4 Neft Dashlari and Palchiq Pilpilassi oil fields



The Table below indicates numbers of the collector and supplier platforms covered by the proposed project activity. The indicated numbers enable the unique identification of this project activity. The project spreads over a region with the coordinates 40.00°N to 41°N and 50°E to 51°E. The precise coordinates of each platform are strictly confidential, as Azerbaijan is still formally in state of war and as platforms are considered as a primary target. A detailed map with the location of the platforms has been provided to the validator.

Table A.4.1.4: Collector and supplier platforms involved in the project

No.	Project site – Collector platform	Connected supplier platforms
1	2192	2192, 679, 1620, 2223
2	1517	M-1, 1501, 1923, 201, 348, 1757, 1745, 1741, 1767, 1926, 1517, 259, 258
3	741a	501, 741, 1544
4	2346	2346, 915, 1624
5	1005a	416a, 1304, 1005
6	1201	1063, 1183, 1100, 1077, 1126, 1127, 1157, 1201, 1145, 1146
7	1799	1799, 606, 1773, 1594, 419a, 516 a, 1956, 1955 1954, 1645, 617
8	810	1887, 2112, 810

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

The project activity involves recovery and utilization of gases generated as a by-product of oil production activities, which would be vented in absence of the proposed project activity.

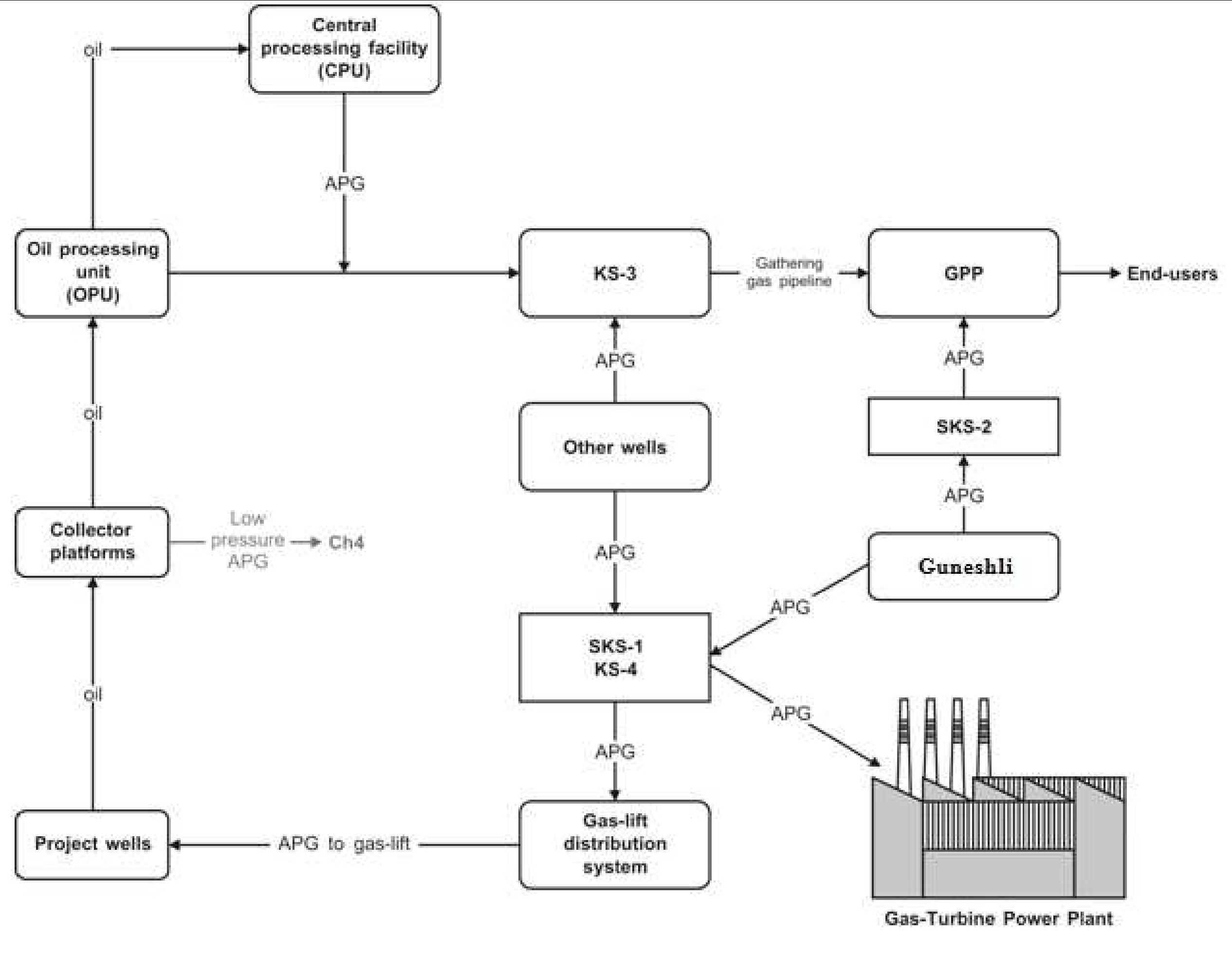
The corresponding category is: (10) Fugitive emissions from fuels.

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

Scenario Prior to Project Start. Technical facilities installed and operating at Neft Dashlari and Palchiq Pilpilassi oil fields are rather outdated. LP APG has been vented into atmosphere since very beginning of oil production at the fields. The crude-oil emulsion - the mixture of crude oil, water and associated gas - is transported from oil wells to collector platforms. At these collector platforms recovered oil quantities are measured and low- pressure (0.08-0.2 MPa) associated gas is separated from crude oil. The recovered low-pressure associated gas is vented directly at the collector platform in absence of the project activity.
The remaining crude-oil emulsion is further transported to oil processing units (OPU) and central processing facilities (CPF) for further separation. At OPU and CPF crude-oil emulsion goes through several separation stages. At the separators the associated gas is recovered and compressed from 0.08-0.2MP to 0.5MPa which enables its transportation to the central compressor facility KS-3. Each OPU and CPF is connected by gathering gas pipelines to the central hub of OGPD. Gas recovered at OPU and CPF is delivered to the central hub, where it is compressed for further on-site utilization.
The associated gas recovered at OPU and CPF has been used for gas-lift operations, combustion in an on-site gas-turbine power plant (GTPP), and for transportation to onshore gas processing facilities. Additionally, since 1986 associated gas has been delivered to OGPD Neft Dashlari from neighbouring oil fields including OGPD Guneshli. This gas is *inter alia* used for gas-lift operations at Neft Dashlari and Palchiq Pilpilassi oil fields. For the purpose of gas-lift operations gas is compressed in the compressor facility SKS-1 and KS-4 and delivered to the gas-lift distribution system, whereof gas goes to individual oil wells. The forecast gas-lift gas demand is covered by current associated gas production at OPU and CPF and by gas deliveries from the neighbouring oil fields. Thus, no other sources of gas-lift gas will be involved in the foreseeable future.

GTPP receives associated gas from the compressor facilities SKS-1 and KS-4. The consumed gas quantities are measured continuously. GTPP supplies electricity and heat to OGPD Neft Dashlari and neighbouring oil and gas fields. Four gas-turbines 12 MW each have been operational since 1987. The power plant covers own energy demand completely and supplies additional energy to other oil fields. There is no connection to the national power grid. Thus, increase in own energy production, and hence additional gas demand, is not expected in the near future. OGPD is considering replacement of the gas-turbines by new ones with the same capacity, but there is no final decision on this.
Excess associated gas (i.e. gas not utilized onsite in GTPP or in gas-lift operations) is delivered to the onshore Garadah Gas Processing Plant (GPP). At the GPP, the recovered gas is processed to LPG and dry natural gas. There is no CNG production.

Figure A.4.3.1. Scenario existing prior to implementation of the project activity



Prior to Project Scenario Equals the Baseline Scenario. The situation existing prior to the implementation of the proposed project described above represents the baseline scenario and is shown in a schematic illustration in Figure below. In the baseline scenario the low-pressure associated gas will not be used (e.g. as a fuel), but vented at collector platforms. In this case, according to the applied baseline methodology AM0009 version 05 emission sources include combustion of fossil fuels at end-users that are produced from non-associated gas or other fossil sources. The main source of emissions in the baseline is CO_2, while CH_4 and N_2O are neglected in order to remain conservative.

Project Scenario. The proposed CDM project aims at reduction of LP APG venting at eight offshore collector platforms. The collected LP APG will displace other fossil fuels produced from non-associated gas or other fossil sources at end-users. The project will use the following equipment:

Project Scenario - Compressors for collecting and transportation of recovered low-pressure associated gas:

> **NQK-7/1-5 Compressors.** Each of eight collector platforms will be equipped with compressors powered by electricity generated by the existing GTPP. The project operator has selected a reliable and locally produced compressor type NQK-7/1-5, as shown in figure below. According to the technical specification the compressors capacity amounts to 75 kW. These will be used for

the transportation of gas from platforms to the central hub of the oil and gas production department.
NQK-7/1-5 has an energy demand of 75 kW and may compress 417.7 m3 per hour (Source: T. M. Verdiyev: Compressors with rocking cylinder for infield collection and transportation of gas, document can be provided to DOE upon request).
The NQK compressors feature an average lifetime of 20years, which in practice may be exceed if good maintenance practices are applied. The NQK compressors shall undergo major maintenance each 20,000 hours of operations when wear parts need to be substituted.
The load factor (based on recent operation data) amounts to 77.71% and the efficiency amounts to 0.23 kWh/m3 compressed gas.

Table A.4.3.2. Compressor NQK-7/1-5

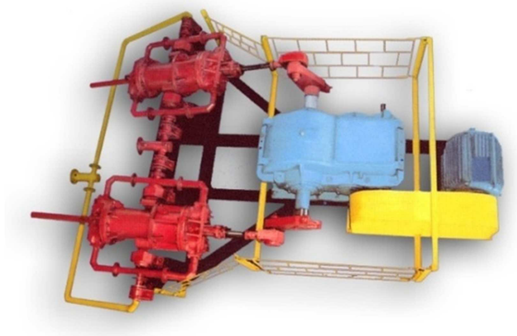


Table A.4.3.1 shows number of compressors to be installed at each of project sites. For assuring continuous operation of project equipment additional compressors will be installed on project sites.

Table A.4.3.1 Compressors to be installed

No	Project site: Collector platform	Number of compressors installed	Number of compressors in operation	Operational hours per year
1	2192	5	3	8760
2	1517	7	6	8760
3	741a	5	3	8760
4	2346	9	7	8760
5	1005a	2	2	8760
6	1201	10	9	8760
7	1799	5	2	8760
8	810	4	4	8760

- **Gas Collection Pipeline System.** New gas pipelines will connect collector platforms with the gathering gas pipeline, which will deliver the recovered gas to the central compressor facility KS-3. This system will connect the eight collector platforms with the gathering gas pipeline.
  The gas pipeline features a total length of 19,977m and its diameter ranges from 150 to 200mm. Details are provided in the table A.4.3.2 below. SOCAR's own calculations show that 150,000

m3 can be passed easily. Hence, the proposed project's associated gas volume can pass without any barriers.

Table A.4.3.2. New gas pipelines

No	Project site	Length of gas pipelines to be installed, m	Pipeline diameter, mm
1	2192	1,520	150
2	1517	802	150
3	741a	1,305	200
4	2346	1,200	200
5	1005a	9,000	200
6	1201	4,540	150
7	1799	300	150
8	810	1,310	200

After the recovered gas is compressed it will be transported to the existing central compressor facilities using the existing oil and gas infrastructure (pipelines, etc.). No additional pipeline from the central compressor facilities to the onshore processing plant need to be constructed.

- **10GCNAM 2/5-55 Compressors** will be used for the transportation of gas from the central hub to the on-shore gas processing plant.
  10GCNAM 2/5-55 has an energy demand of 1,177 kW at full load and may compress 10,800 m3/h. 10GCNAM feature an average lifetime of 40 years which in practice may be exceed if good maintenance rules are applied. The compressors shall undergo major maintenance every 72,000 hours of operation. In the course of this maintenance, the compressor's wear parts need to be replaced.
  The load factor amounts to 48% and by the efficiency/average energy consumption amounts to 0.073m3 low pressure APG/m3 compressed gas.
  All compressors are aggregated to four central compressor facilities: SKS-1, SKS-2, KS-3 and KS-4. SKS-2 is located at some geographical distance; SKS-1, KS-3 and KS-4 are located close to each other. Figure A.4.3.3 below illustrates the technical setup for each of the four facilities. The central compressor facility KS-3 compresses the project gas for further transportation.
  The central compressor facilities are powered by low pressure associated gas. The gas recovered by the project activity, along with the gas from the OPU, CPU and other wells of the two project oil fields will be transported through the gathering gas pipeline and compressed in the facility KS-3. The recovered gas will be further transported to the gas processing plant.

Table A.4.3.3 shows the amount of 10GCNAM compressors aggregated under each of the central compressor facilities. The capacity of the compressors satisfies the demand of the project activity. No additional compressors at the central hub are required for transportation of the recovered gas to GPP.

Table A.4.3.3. The existing central compressor station and its facilities

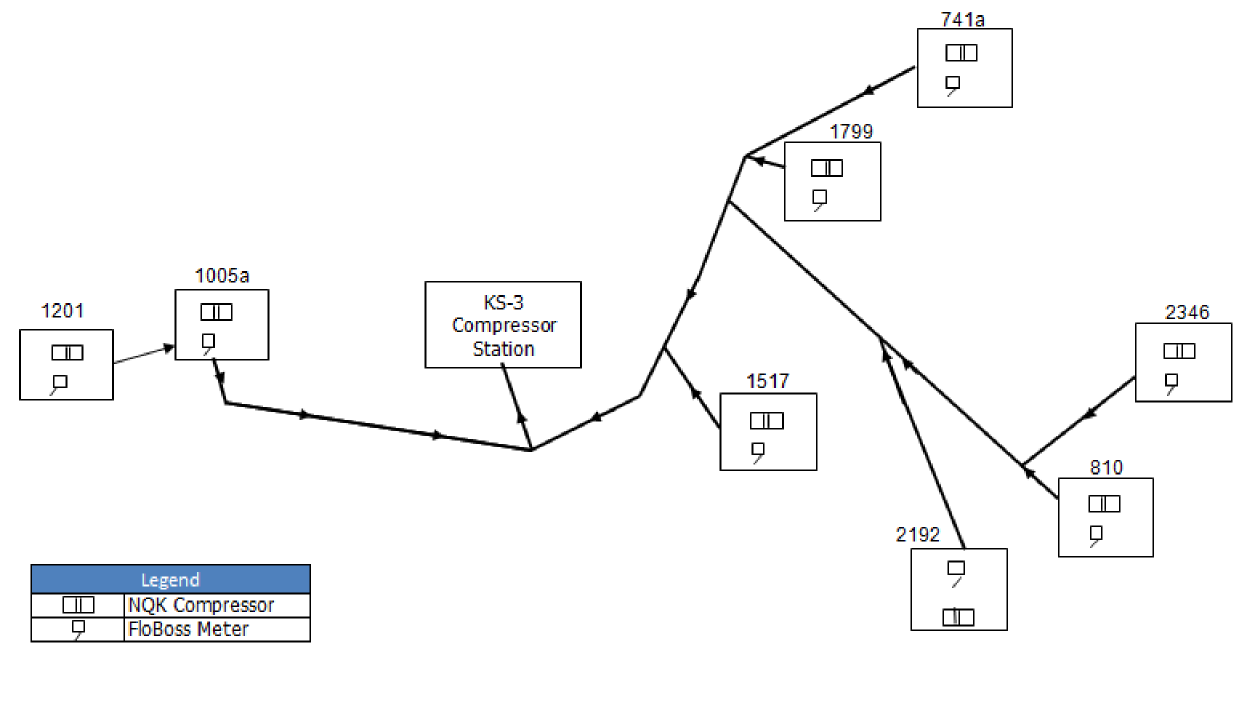
Compressor facility	Compressor type	Number of compressors
SKS-1	10GCNAM2/5-55	10
KS-3	10GCNAM2/5-55	6
KS-4	10GCNAM2/5-55	8
Total		24

Project Scenario - Metering Devices and Auxiliaries:

- **Flow Meter.** Flow meters of the type FloBoss – 107 were installed. It measures volume of gas passing through the equipment. This instrument measures the volume, temperature and pressure

up to 63 MPa. FloBoss is equipped with multi-parametrical sensors for measuring pressure, pressure drop and temperature. The instrument automatically stores all obtained data in digital formats. The manufactures specifications may be provided to the DOE upon request.
As can be seen from the below figure, FloBoss metering devices are installed at each collector platform which allows for the adequate measurement of the proposed project's APG volume.

Figure A4.3.2: Location of FloBoss Metering Devices



- **Remote Operations Controllers** (ROC-107), Emerson (remote automation system);
- **Differential Manometers** DSS-712-M1 (metering and calculating device for determination of gas pressure).
- **The NCV** will be determined outside of the project boundary in a certified laboratory in frequent intervals.

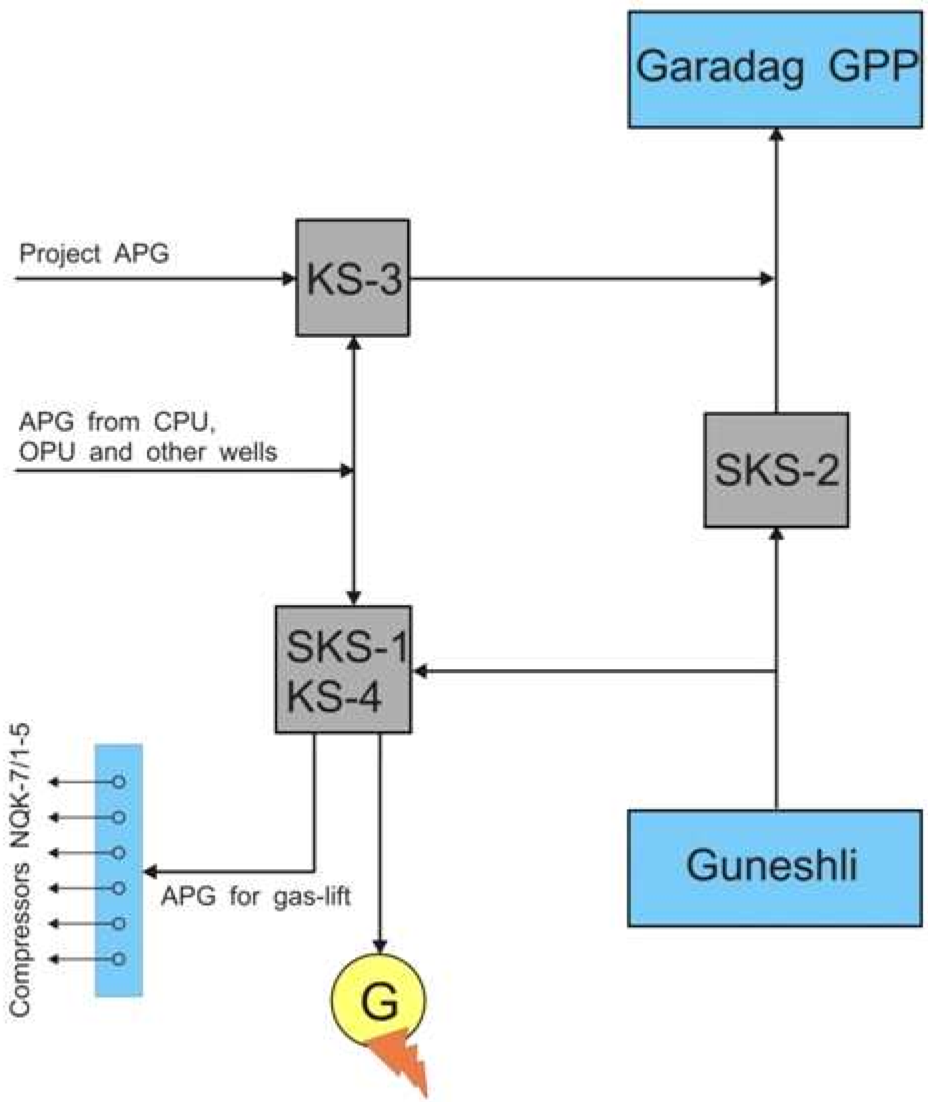
Project Scenario – Consideration of the Mixing of APG from Various Sources at the Central Compressor Facilities
The gas system comprises features four central compressor facilities: SKS1, SKS-2, KS3 and KS4, each serving a different purpose.

- SKS-1 and KS-4 compresses
  - a) gas originating from the neighbouring gas field 'Guneshli' and
  - b) APG from the CPU, OPU and other wells.

  The compressed gas is
  - c) used for the gas lift and
  - d) supplied to the Gas Turbine Power Plant.
- SKS-2 compresses the remaining gas originating from the neighbouring gas field 'Guneshli'gas. The compressed gas is supplied to the Garadagh Gas Processing Plant.
- KS-3 compresses the project's APG as well as from the CPU and the OPU and other wells. This gas is fed into the pipeline and supplied to the Garadagh GPP.

The detailed technical setup is presented in the below figure. Managing the compressor units KS-3 and SKS-1/KS4 separately ensures that the project gas is delivered to the GPP. The project gas will not be mixed with the gas serving the gas lift.

Figure A.4.3.3: Detailed Structure of the Central Compressor Facilities



Based on this technical setup it is ensured that the project gas is not mixed with gas which is used for the gas lift system. Additionally the below considerations are provided:

- A gas balance is provided in Annex 3, Table AN3.2. The balance shows significant surplus for each year of the project activity. This demonstrates that the project's APG is not needed at any point in time for meeting the demands of the gas lift or the gas turbine power plant.
- The project cannot be implemented to serve the gas lift, as this would be financially un-attractive.
  - SOCAR receives a selling price of 40.63€/1000m3 and a share for gas delivered to the GTPP (9.92€/1000m3), aggregated prices amount to50.56€/1000m3.
  - Buying the gas from 'May 28' costs 28.59€/1000m3.

- The proposed project's costs for recovering the APG amounts to 25.16€/1000m3.

If the project would aim at replacing gas to be purchased from 'May 28', it would reduce its revenue from 21.97€/1000m3 to 3.43€/1000m3. In this case, the project would feature a negative Internal Rate of Return of -37% combined with a negative Net Present Value. This setup is clearly financially not attractive and would not be implemented. It is concluded that SOCAR, as a profit oriented company, does not implement the proposed project to meet the gas lift demand.

Project and Baseline Emission Sources and GHGs Involved. The baseline scenario is characterized by venting of LP APG which is the only emission source. This involves the emissions of CH4, CO2 and N2O whereas following AM 009, Version 5, only CO2 was considered.

The project scenario involves CO2 emissions from electricity generation (for compressors NQK 7/1-5). The electricity is provided by the GTPP which operates on APG. The project activity also involves CO2 emissions from fossil fuel consumption for the compression of APG by 10GCNAM2/5-55. Both emissions refer to CO2 and, following the guidelines of AM009, N2O and CH4 are neglected. The project emissions are determined in Section B in a conservative manner and are subtracted from the overall volume of emission reductions.

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

A.4.4: Estimated emission reduction amount

Years	**Annual estimation of emission reductions in tonnes of CO2 e**
2013	272,223
2014	258,773
2015	245,942
2016	233,701
2017	222,024
2018	210,883
2019	200,255
2020	190,116
2021	180,444
2022	171,216
Total estimated reductions (tonnes of CO2 e)	**2,185,577**
Total number of crediting years	**10**
Annual average over the crediting period of estimated reductions (tonnes of CO2 e)	**218,558**

A.4.5. Public funding of the project activity:

There is no public funding involved in this project. The project will be financed by the project participants included in Annex 1.

SECTION B. Application of a baseline and monitoring methodology

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

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The proposed CDM project activity applies the approved baseline and monitoring methodology AM0009 version 05 "Recovery and utilization of gas from oil wells that would otherwise be flared or vented".
This methodology also refers to the latest approved versions of the following tools:

- "Tool to calculate project or leakage CO2 emissions from fossil fuel combustion" (Version 02);
- "Tool to calculate baseline, project and/or leakage emissions from electricity consumption" (Version 01);
- " "Tool for the demonstration and assessment of additionality" (Version 05.2).

"Tool to assess the validity of the original/current baseline and to update the baseline at the renewal of a crediting period" (Version 03)

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

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The selected baseline and monitoring methodology is applicable to project activities that recover and utilise associated gas and gas-lift gas from oil wells that was flared or vented prior to the implementation of the project activity. In particular the proposed project activity meets the following conditions, specified in the methodology AM0009 version 05:

1. 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 and compressed into a gas pipeline without prior processing; and/or transported to a processing plant where it is processed into hydrocarbon products (e.g. dry gas, LPG and condensate) 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 and gasified again, before it finally enters the gas pipeline.
2. 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;
3. 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;
4. 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 gas-lift gas.

Additionally, the approved methodology AM0009 version 05 is only applicable, if the identified baseline scenario is:

a) 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
b) The continued operation of the existing oil and gas infrastructure and without any other significant changes(scenario P4); and
c) 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.

The proposed project activity is focused on recovery and utilization of the low pressure associated gas at Neft Dashlari and Palchiq Pilpilassi oil fields, that otherwise would be vented. The low pressure gas will be recovered from the operating oil wells and transported to the gas processing plant (GPP). The proposed CDM project meets the above methodological applicability criteria as follows:

1. The recovered low pressure associated gas under the project activity will be compressed and transported to the gas processing plant without prior processing. Recovered gas will not be used onsite to meet energy demand, because the existing onsite gas power plan receives enough high pressure gas from other sources. No other gas consuming energy production facilities exist at OGPD facilities. (Reference: Interviews with Chief Engineer of OGPD & Technical Feasibility Study: orders No. 10062, No. 10139 and No. 10307). At the GPP, the recovered gas is processed to dry natural gas and to LPG. CNG is not produced and hence, no related leakage emissions arise.
2. The project activity will have no impact on the process of oil production at Neft Dashlari and Palchiq Pilpilassi oil fields (Reference: interview with Chief Engineer of OGPD; oil production forecast table was made available to the validator during the onsite visit).
3. Operating wells at Neft Dashlari and Palchiq Pilpilassi oil fields comprised by the project activity apply gas-lift techniques. These wells are supplied by the existing gas-lift gas distribution system and this system is not changed in the course of the project activity. The gas lift demand is met by the gas provided by the OGPD Guneshli operating the ‘May 28’ oilfield, the OPU, CPU and gas from other wells. This ensures that the project APG is not mixed with the gas serving the gas lift.
4. All low pressure associated gas to be recovered originates from the operating oil wells of Neft Dashlari and Palchiq Pilpilassi oil fields. (Reference: internal reports and map of platforms of OGPD Neft Dashlari were made available for the validator during the onsite visit)

The final applicability condition is fulfilled as demonstrated in Section B.4. The identified baseline scenario is:

- the continuation of the current practice of venting the low-pressure associated gas; and
- the continued operation of the existing oil and gas infrastructure without processing of any recovered low-pressure associated gas and without any other significant changes; and
- 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 (Reference: an internal gas delivery and lift-gas demand report was made available to the validator during the onsite visit. The report confirmed that quantity of recovered low pressure gas is insufficient to cover the demand of OGPD, hence lift-gas deliveries from the same sources will be continued). The proposed project will not alter the current practice regarding the purchase of APG to cover the demand of the gas lift.

The baseline scenario is identified following the baseline methodology procedure.

The approved baseline and monitoring methodology AM0009 version 05 is considered to be applicable to the proposed CDM project activity.

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

According to the Glossary of CDM terms, version 05 the project boundary shall encompass all anthropogenic sources of greenhouse gases (GHG) under the control of project participants that are significant and reasonably attributable to the CDM project activity. The project boundary was determined according to the CDM methodology AM0009 version 05 as shown in Table below.

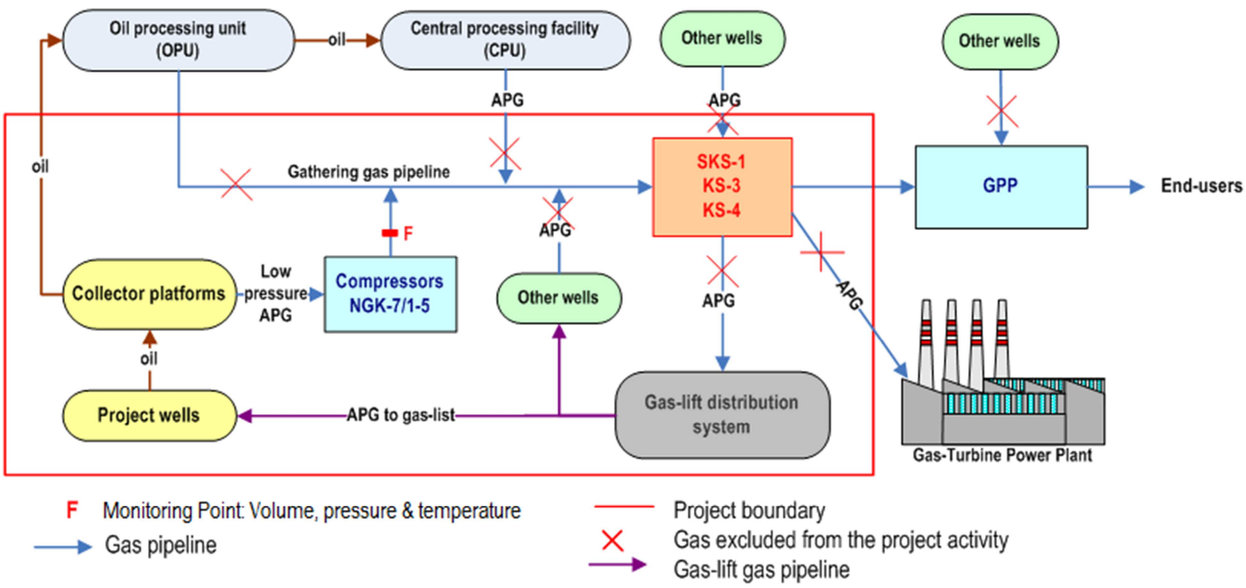
Table B.3.1: Project boundary description

Project boundary according to	Project boundary

AM0009, Version 05	Neft Dashlari and Palchiq Pilpilassi oil fields
The project oil reservoir and oil wells where the associated gas and/or gas-lift gas is collected;	Neft Dashlari and Palchiq Pilpilassi oil fields
The site where the associated gas and/or gas-lift gas was flared or vented in the absence of the project activity;	Eight offshore collector platforms and the connected supplier platforms of Neft Dashlari and Palchiq Pilpilassi oil fields
The gas recovery, pre-treatment, transportation infrastructure, including where applicable, compressors;	New compressors installed at the offshore collector platforms, collecting pipelines, central compressor facility.
The source of gas-lift gas	Gas-lift gas distribution system including respective pipelines, gas inlet in the central compressor facility from the oil fields of OGPD “28 May”, OPU and CPF of OGPD Neft Dashlari.

Figure B.3.1 shows the identified project boundary as well as the monitoring points for determination of the baseline and the project emissions.

Figure B.3.1. Schematic illustration of the project activity



The table below shows the greenhouse gases included in or excluded from the project boundary.

Table B.3.2: GHG emission sources

	Source	Gas	Included Yes/No	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, pretreatment, transportation, and if applicable, compression 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

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

The baseline for a CDM project activity is the scenario that reasonably represents the anthropogenic emissions by sources of greenhouse gases (GHG) that would occur in the absence of the proposed project activity[2]. According to the applied methodology AM0009 version 05 identification of the baseline scenario is conducted based on evaluation of project alternatives. Furthermore, additionality of the proposed CDM project activity is demonstrated based on four steps specified in the methodology. This evaluation confirms that continuation of venting low-pressure associated gas at Neft Dashlari and Palchiq Pilpilassi oil fields will continue in absence of the proposed project activity.

The methodology AM0009 version 05 provides four steps approach for identification of the baseline scenario and determination of additionality:

Step 1: Identify plausible alternative scenarios
Step 2: Evaluate legal aspects
Step 3: Evaluate the economic attractiveness of alternatives
Step 4: Common practice analysis

STEP 1: Identify plausible alternative scenarios

Under the methodology AM0009 version 05 the project activity involves three components: utilization of gas from oil wells, operation and installation of oil and gas infrastructure, and use of gas-lift. For each of these components plausible alternative scenarios have to be identified accordingly.

1a. Utilization of gas from oil wells in absence of the project activity

The plausible alternative scenarios could under AM0009 version 05 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 demands for power generation 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 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.

The listed alternative scenarios are analyzed below:

[2] Glossary of CDM terms, Version 05

G1: Venting of low pressure associated gas at the production sites of Neft Dashlari and Palchiq Pilpilassi oil fields is a regular practice. LP APG is released into atmosphere directly from the separation facilities. There are no limitations for continuation of this practice. Therefore, this is a plausible alternative.

G2: Flaring of low pressure associated gas has never been applied at offshore platforms of SOCAR. Only onshore oil fields or facilities situated close to settlements are obliged to flare not-utilized gases. This alternative is rather not plausible as gas flaring would require additional investments in flaring facilities (Height of a standard flare is insufficient).

G3: The oil production sites of Neft Dashlari and Palchiq Pilpilassi, as well as the production sites of neighbouring OGPD “28 May”, are supplied by an onsite 48 MW power generation plant situated at OGPD Neft Dashlari. The installed turbines are fuelled by high pressure APG delivered form the central compressor facility (SKS-1 and KS-4). Thus, there is no additional energy demand onsite and no excess associated gas is required for energy production. This alternative does not represent a plausible scenario.

G4: Injection of the recovered LP APG into an oil or gas reservoir was evaluated by the project participants, but considered as not financially attractive. There are no gas fields close to the Neft Dashlari and Palchiq Pilpilassi fields and transportation of LP APG to neighbouring gas fields is not cost-effective. The operating oil wells are equipped with gas-lift system. But for this purpose additional pre-treatment and compression of low-pressure APG is required. These additional investments are not cost-effective taking into consideration availability of own high-pressure gas from OPU and CPF and low-cost gas deliveries from OGPD “28 May”. This alternative is thus not plausible.

G5: The project participants consider recovery, transportation and processing of low pressure gas for distribution of products thereof to end-users. This alternative represents the proposed CDM project activity. Under this activity the recovered gas will be delivered from Neft Dashlari and Palchiq Pilpilassi oil fields to Garadagh gas processing plant. This alternative is considered to be viable.

G7:

G6: There is a chemical industry situated onshore, which uses natural gas for production of polyethylene. The recovered gas can only be used as feedstock in this production process, when pre-treated. Additionally a new gas pipeline have to be built to the chemical plant. Due to enormous costs connected with a new pipeline construction, this alternative is considered as not feasible.

From the listed alternatives two options have been considered as plausible scenarios:

G1: Release of the associated gas into the atmosphere at the oil production site (venting);

G5: Recovery, transportation, processing of the associated gas and distribution of products thereof to end-users without being registered as a CDM project activity.

1b. Operation and installation of oil and gas infrastructure in absence of the project activity

The methodology AM0009 version 05 provides the following alternatives for identification of baseline scenario:

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 no 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 processing of any recovered associated gas and/or gas-lift gas and without any other significant changes;
P5: Due to its quality the recovered associated gas cannot be delivered to a natural gas pipeline without prior processing. This alternative overlaps with G7 and is considered to be not feasible.

Taking into consideration the framework of the proposed CDM project activity the listed alternatives were evaluated as follows:

P1: The existing Garadagh gas processing plant already utilizes high pressure associated gas and has capacities for increase high pressure gas processing. Additionally, the low-pressure associated gas has much lower economic value, when recovered, compressed, transported and processed into end-user products. Hence, construction of a new plant for processing of LP APG is considered to be not feasible.
P2: Similar to the alternative P1 this scenario is not plausible, as no less cost intensive technologies are available for processing of low-pressure associated gas.
P3: The project participants evaluate an option of supplying recovered gas to an existing Garadagh gas processing plant and constructing the necessary infrastructure including compressors and gas pipelines. This alternative represents the proposed project activity and is considered to be feasible;
P4: There are no limitations for continuing operation of the existing oil and gas infrastructure without processing of any recovered low-pressure associated gas. Therefore, this alternative is considered to be plausible.
P5: Due to its quality the recovered associated gas cannot be delivered to a natural gas pipeline without prior processing. This alternative overlaps with G7 and is considered to be not feasible.

Having reviewed different alternatives for the operation and installation of oil and gas infrastructure two of five scenarios are considered to be feasible:

P3: Supplying recovered gas to an existing gas processing plant and constructing the necessary infrastructure; and
P4: Continuation of the operation of the existing oil and gas infrastructure without processing of any recovered gas and without any other significant changes.

1c. Use of gas-lift in absence of the project activity

The Neft Dashlari and Palchiq Pilpilassi oil fields have applied gas-lift techniques since many years and are planning to continue with this approach. The methodology AM0009 version 05 provides the following alternatives for identification of baseline scenario:

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.

The provided alternatives were analyzed by the project participants as follows:

O1: Currently for gas-lift operations high pressure associated gas is delivered from the central compressor facilities, in particular from the facilities SKS-1 and KS-4. Neft Dashlari regularly specifies the middle-term oil production forecast and clearly determines the quantity of lift-gas required. There is no reason for dramatic increase or decrease in use of gas-lift gas. Therefore the forecast gas quantity will be required for gas-lift. In the absence of the proposed CDM activity the existing practice would continue as there are no limitations for using high pressure APG. This alternative is feasible.

O2: There are no other sources of gas available to replace the existing practice. Deliveries of natural gas for gas-lift operations are technically feasible, but much too expensive. This alternative is, therefore, not feasible.

O3: On the offshore platforms the only alternative to the gas-lift method is the air-lift well operation, which will require additional investment in compressors and may require additional security measures. Reduction of gas demand through air-lift would cause very high costs, as the whole system has to be modified. This alternative is not feasible so far.

O4: This alternative overlaps with alternative O2. There are no other sources of gas-lift gas available. This option is not plausible.

O5: The oil production sites of Neft Dashlari and Palchiq Pilpilassi cannot operate without gas-lift system. Hence, this scenario is not feasible.

From the five alternatives provided by AM0009 version 05 for this category only one alternative is feasible:

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.

All alternatives considered plausible will be analyzed in the Steps 2 to 4. For this analysis the alternative baseline scenario are formulated based on identified alternatives listed in Table B.4.1.

Table B.4.1 Plausible baseline alternatives

Component of the baseline scenario	Credible and plausible alternatives
Utilization of gas from oil wells	G1 (current practice), and G5
Operation and installation of oil and gas infrastructure	P3, and P4 (current practice)
Use of gas-lift gas	O1 (current practice)

Accordingly the following two baseline alternatives were formulated:

Alternative 1: Continuation of current practice of venting of the low-pressure associated gas at the oil production site (G1), operation of the existing oil and gas infrastructure without any other significant changes (P4), and use of gas from the same source and in the same quantity for the gas-lift system as under the project activity (O1). This alternative is described in Figure A.4.3.1.

Alternative 2: Recovery, transportation, processing of recovered gas in the existing gas processing plant and constructing the necessary infrastructure (G5 and P3), without registered as a CDM project activity, and use of gas from the same source and in the same quantity for the gas-lift system as in the baseline. This alternative is described in Figure B.3.1.

The Alternative 2 represents the proposed project activity without being registered as CDM project.

STEP 2: Evaluate legal aspects

In this step both alternatives identified in step 1 are evaluated for compliance with all applicable legal and regulatory requirements in Azerbaijan.

Alternative 1: Continuation of the current practice of venting the low pressure associated gas), operation of the existing oil and gas infrastructure without any other significant changes, and use of gas from the same source and in the same quantity for the gas-lift system as under the project activity.

Release of associated gas into atmosphere is not prohibited by law in Azerbaijan Republic. Hence, this alternative is in compliance with relevant legal and regulatory requirements. The atmospheric emissions from venting and flaring of associated gas are a subject of different laws and regulations. The Government of Azerbaijan introduced numerous laws and resolutions for regulation of disseminating harmful substances, including GHG emissions. After the ratification the Kyoto Protocol in 2001 the Government of Azerbaijan put its efforts on adaptation of the national legislation in regard to reduction of GHG emissions into atmosphere. The relevant legal regulations, introduced so far, are listed below.

<u>Law of the Azerbaijan Republic on Protection of Atmospheric Air (2001)</u>

This law provides general regulations on the principles for protection of atmospheric air, quality norms for atmospheric air, norms for release of harmful substances, and permits for dissemination of harmful substances. This document describes the key aspects of air protection, whereas individual principles and rules are determined by other governmental regulations and standards. The Ministry of Ecology and Natural Resources (MENR) of the Azerbaijan Republic was appointed to be the responsible authority for implementation of the law including issuance of emission permits and monitoring.
Furthermore, the law also provides general regulations for those facilities, which can not comply with permitted level of emissions. Thus, for such entities MENR may exceptionally determine a temporary agreed dissemination of harmful substances[3].

<u>Resolution №112 of the Cabinet of Ministers of the Azerbaijan Republic (2002)</u>

This resolution determines the rules on (1) state registration of harmful substances rules impacts on atmospheric air, (2) issuing of permits for release of harmful substances and impacts on atmospheric air, and (3) tariffs for obtaining permits for release of harmful substances and impacts on atmospheric air and rules on utilizing financial resources derived from those payments. According to this document the greenhouse gases fall into the fourth category of hazardous substances, which determines the basis for payments for emission permits. The emission permits are issued by the Ministry of Ecology and Natural Resources (MENR) for three years. The permitted level of emissions is defined and monitored by MENR according to existing technical normative.

<u>Resolution №122 of Cabinet of Ministers of Azerbaijan Republic (1992, adapted 2002)</u>

This resolution – “On payment for natural resources, application of payment for release of pollutants to environment and utilization of financial resources derived from those payments” - sets out the payment tariffs for permitted level of emissions for different pollutants. The tariffs are defined in Azerbaijani Manat (AZN) per tonne for each of 89 types of atmospheric pollutants. According to this regulation oil companies are obliged to pay 0,104 AZN per tonne of associated petroleum gas emitted into atmosphere.

<u>Resolution №159 of Cabinet of Ministers of Azerbaijan Republic (2002)</u>

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[3] Law of the Azerbaijan Republic on Protection of Atmospheric Air (2001), Article 10, 10.4

This resolution approves the rules on certification of conformity of fuel, engines, technological processes, transport vehicles and other mobile equipment to requirements of protection of atmospheric air. According to this resolution, it is obligatory for any production facility having harmful impact of atmospheric air to get certified. The conformity certificates are issued by the National Committee of Standardization, Metrology and Patenting. Within the certification process the committee evaluates either a facility operates in conformity with requirements of MENR. Upon successful evaluation the certificate is issued for period of two years. Any oil production unit flaring or venting associated gas is a subject of periodic certification under this resolution.

Resolution №198 of Cabinet of Ministers of Azerbaijan Republic (2002)

This resolution determines a framework for definition of technical normative for emissions from stationary sources including transport and other mobile vehicles as source of pollutants released to atmosphere. The resolution assigns the Ministry of Environment and Natural Resources to prepare technical normative and permitted volume of emissions for each source. For stationary facilities technical normative is defined by existing standards and where such standard does not exist the MENR will use its own methods to define them.

Taking into consideration the laws and resolutions described above, the oil producing companies had no or very limited economic incentives to improve associated gas recovery in Azerbaijan. Even though there is a clear Government’s intention to improve air quality through reduction or limitation of harmful emissions, there are still legal options for exceptions and deviation from the rules. The continuation of existing practice at Neft Dashlari and Palchiq Pilpillasi oil fields is, therefore, a feasible alternative complying with all applicable national regulations.

Alternative 2: The proposed project without being registered as a CDM project activity.

The proposed project activity focuses on recovery, transportation, processing of recovered gas in the existing gas processing plant, and injection of the associated gas into an oil or gas reservoir. The planned activity is not prohibited by law and can be implemented in accordance with all applicable legal and regulatory requirements listed above.

STEP 3: Evaluate the economic attractiveness of alternatives

Both alternatives considered feasible under the Step 2 are assessed for their economic attractiveness in this step. Under the methodology AM0009 version 05 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”, Version 5.02. According to the tool a benchmark analysis based on IRR and Net Present Value (NPV) is determined to be the most appropriate analysis method to assess economic and financial attractiveness of the project alternatives.

Sub-Step 2b: Option III. Benchmark analysis

Alternative 1 representing continuation of current practice is not evaluated specifically, as no investment will be made according to this option. Economic attractiveness of Alternative 2 (Proposed project activity without CDM) is analyzed in detail with evaluation of the determined indicators (IRR, NPV).

The conducted analysis uses the following parameters:

- Overall projected production of low pressure associated gas;
- The projected quantity of gas transported to the gas processing plant;
- The agreed price for the delivery of recovered gas to the gas processing plant. Please note, following SOCAR’s contractual arrangements, the pricing does not consider the variation of the NCV of APG sold.
- Capital expenditure for all oil and gas infrastructure, including compressors, metering devices, pipelines, construction and installation works, etc. (CAPEX);
- Operational expenditure including costs of gas recovery and transportation under the project activity (OPEX);
- All revenues from the project operations, including revenues from selling recovered gas, savings from non-payment of environmental fees and gas venting permits;
- The fiscal regime of for investment projects in Republic of Azerbaijan.

For the purpose of the investment analysis all costs and prices are treated in Euro. The average exchange rates of December 2007 (0.803 EUR/AZN) are taken into consideration in calculations. In following the values and parameters used in the investment analysis are described in more detail:

Table B.4.2.: Description of parameters used in the investment analysis	
Overall projected production of low pressure gas	The quantity of low pressure gas produced can be directly linked to the oil production. The oil production forecast provides a basis for estimation of associated gas production. The quantity of LP APG is determined for each of eight project sites.
Projected quantity of gas transported to the gas processing plant	Compressors 10GCNAM2/5-55 installed at the central compressor facility KS-3 are running on low associated gas. Thus, the quantity of totally recovered gas is reduced by the gas volume required to power the central facility KS-3. According to the state regulations the gas prices are given in AZN/Sm^3. For this reason the gas quantities are treated in standard cubic meters within the investment analysis.
Agreed price for the delivery of recovered gas	In general prices for gas and electricity are determined by the State Tariff Council. In 2008 the selling wholesale price for gas amounted to 35,59 AZN/1000m^3. This price corresponds to the prices of gas delivered to GPP. The consumer price of 100 AZN/1000m^3 is achievable for the facilities and suppliers, delivering gas to end-users (e.g. GPP). The investment analysis takes into consideration a wholesale price of gas including a twenty five percent price premium for gas distributed with end-consumers by GPP. This conservative assumption involves additional indirect revenues of OGPD Neft Dashlari.
Capital expenditure	The capital expenditures include all costs directly related to the implementation of the proposed project activity: costs of equipment (compressors, connecting pipelines, metering devices, etc.), construction and installation works, technical planning, contingences, etc.
Operational expenditure	The operational expenditures are estimated by OGPD Neft Dashlari based on its average associated gas production costs. OPEX are determined by multiplying the average gas production costs by the projected quantity of gas recovered per year. The period of the assessment is eleven years. This period includes the costs of major maintenance and rehabilitation.
Revenues from the project	The expected revenues comprise both revenues from selling the

operations	recovered gas to GPP and savings from the reduced environmental payments. The savings are calculated based on the recovered gas quantity and environmental fees payable for gas venting.
Depreciation	In order to calculate the post-tax IRR, the depreciation of the NQK compressors, gas pipelines and meters has been taken. Other investment costs are not considered since they are labor costs. The depreciation period considered is 4 years according to the Azerbaijan taxation procedures. [4]
Fiscal regime	At the time point of investment decision (April 2007) the Central Bank[5] interest rate was 12% p.a. This is the interest rate at which commercial banks borrow capital at the central bank. Per definition the Central Bank's interest rate is the discount rate (12%). When commercial banks lend capital to private enterprises they have to add a margin in order to take project and investment risks into account. In order to quantify this margin the country risk premium of 3.6 % defined by the New York University Leonard N. Stern School of Business[6]. For the definition of the benchmark the discount rate is increased by the country risk premium amounting to 15.6 %.

The summary of the investment analysis is demonstrated in Table B.4.3. The calculation of economic indicators is conducted on a project basis excluding expenditures for the project finance. The available parameters calculated for Alternative 1 are presented for comparison with the Alternative 2. Two options for Alternative 2 were analyzed - with and without being registered as a CDM activity and receiving inflows from CERs. It is obvious from the Net Present Value that only by taking into account carbon revenues the project becomes economically feasible.

Table B.4.3.: Summary of the investment analysis.

Economic Indicators	Units	Alternative 1	Alternative 2	
			Project activity not as CDM	**Project activity as CDM**
Capital expenditures (undiscounted)	EUR	-	24,164,225	24,164,225
Operating expenses (undiscounted)	EUR	2,510,506	51,599,934	52,202,199
Operational revenues (undiscounted)	EUR	-	97,765,186	97,765,186
Carbon revenues	EUR	-	-	14,089,612
NPV	**EUR**	**-1,097,068**	**-1,506,570**	**5,376,226**
IRR	**%**	**-**	**9.85%**	**19.30%**

As shown in Table B.4.3 financial returns that can be earned by the project participants through implementing the proposed project are marginal. The investment analysis shows that NPV is negative, which by the rule of thumb means that the project is absolutely unattractive. Also the negative IRR

[4] http://en.wikipedia.org/wiki/Taxation_in_Azerbaijan

[5] Interest rates of the Central Bank of Azerbaijan - http://www.cbar.az/infoblocks/corridor_percent

[6] http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/ctryprem.html

confirms that the project participants would receive higher returns when investing on the capital market. Due to the negative NPV and IRR, the project does not perform well according to both NPV and IRR rules. The IRR-benchmark of 15.6%, which would make the project attractive for an investment, is not reached. The ability to register the project under CDM offers an incentive to further develop the project design through generating carbon revenues (CERs) that will improve the internal rate of return (IRR). Also the project NPV can be improved dramatically when implemented under CDM. The detailed and transparent investment analysis is included in Annex 6.

Sub-Step 2d: Sensitivity analysis

In order to confirm that the conclusions regarding economic attractiveness are robust to reasonable variations in the critical assumptions a sensitivity analysis is conducted. By varying the prices for (a) natural gas, (b) environmental payments for gas venting, (c) investment costs (costs of equipment, construction and installation) and (d) the gas production costs (including the cost of electricity) by +20%/-20% the evaluation of economic indicators is carried out. It was assumed that the selected parameters are the most likely ones to vary because of correlation to world economic parameters and possible strengthening of APG venting and flaring restrictions in Azerbaijan. The table below provides the NPV and IRR values for -20% and +20% variations of one of the parameters while keeping other parameter constant. As can be seen the sensitivity variations make no appreciable change on the economic outcome of the proposed project. NPV stays negative, except in scenarios of decrease in gas production costs, increase in natural gas price and decrease in investment costs. However, IRR indicator does not reach a desirable benchmark of 15.6 % in all four cases.

Table B.4.4.: Sensitivity analysis

Key project economic parameters	IRR at deviation of key economic parameters		NPV at deviation of key economic parameters[7]	
	-20%	+20%	-20%	+20%
Environmental payments	9.60%	10.10%	-1,677,712	-1,335,427
Natural gas price	5.86%	13.47%	-4,088,274	1,075,135
Gas production costs	14.68%	4.33%	1,984,417	-4,997,556
Investment costs (equipment, installation and construction)	13.77%	6.68%	1,103,095	-4,116,235

According to the above analysis of the economic attractiveness none of the alternative scenarios is considered to be more attractive than the proposed CDM activity. Alternative 1 shows negative, but higher NPV and is, thus, more attractive than Alternative 2. Therefore Alternative 2 is the least attractive option of the identified baseline scenarios. Only when implemented under CDM scheme Alternative 2 has a chance to become feasible.

Step 4: Common practice analysis

[7] According to the legal framework of Azerbaijan, flaring and venting is allowed. Still the oil companies do have to purchase environmental permits. These fees have been accounted for as operational costs under the baseline scenario which is considered to be conservative.

For identification of the most credible baseline scenario the common practice analysis is conducted according to the guidance of the "Tool for the assessment and demonstration of additionality" version 05.2 as recommended by the methodology AM0009 version 05. The common practice analysis contains of two sub-steps: analysis of similar activities and discussion on identified similar project activities.

Sub-Step 4a: Analyze other activities similar to the proposed project activity

According to the tool projects are considered similar if they are in the same country/region and/or rely on a broadly similar technology, are of a similar scale, and take place in a comparable environment with respect to regulatory framework, investment climate, access to technology, access to financing, etc.

Flaring and venting of associated petroleum gas represent one of the major sources of GHG emissions in oil and gas industry in the post-soviet region. All of the countries of the Caspian Sea Region are oil producers comprising Russia, Kazakhstan, Turkmenistan, Iran and Azerbaijan[8] and most of them still operate oil wells equipped with outdated soviet facilities. These facilities are often equipped with gas flares or vents. Therefore, release of greenhouse gases into atmosphere represents prevailing practice. Today the countries put emphasis on reduction of APG flaring and venting by introducing new environmental laws and tax regulations. Nevertheless none of the countries strictly prohibits flaring of associated gas, and release of GHG (CH_4 and CO_2) into atmosphere is a subject to environmental payments.

Project activities focused on reduction of associated gas venting or flaring developed in the region during the last years were either financed by international donor organisations or were initiated within the framework of implementation the flexible mechanisms of the Kyoto Protocol. Thus, some ten Joint Implementation projects on recovery and utilization of APG were developed in Russia. All of these projects were developed for onshore oil production facilities, which is not broadly similar technology to the one applied in Azerbaijan and that why not considered in this analysis.

Oil production activities in Azerbaijan and in rest Caspian Sea region are characterized by off-shore exploration. The common practice analysis considers therefore oil production and associated gas approach in Azerbaijan, Kazakhstan, Turkmenistan, and Iran. While associated gas flaring in forbidden oil companies may practically (legally) receive gas flaring permits.

Kazakhstan: In absence of Kyoto Mechanisms there are hardly any projects in the sector of APG recovery implemented in Kazakhstan off-shore fields. According to the Global Gas Flaring reduction Partnership (GGFP) Fact Sheet: First Global Satellite Survey on Gas Flaring [9], Kazakhstan is one of the countries with the highest increase of flaring during the observed period 1995 – 2006. As stated in the interview with KazMunaiGaz to the Eurasia Gas&Oil from September 2007 KazMunaiGaz was preparing the development of new off-shore fields, where they are planning to introduced recovery of associated gas as part of the environmental strategy. [10]

Iran: According to the Global Gas Flaring Reduction Partnership (GGFR) newsletter issue 10[11] from June 2010, Iran is ranking number 3 in 2009 within the flaring countries (after Russia and Nigeria).

[8] http://en.wikipedia.org/wiki/Caspian_Sea

[9] http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/EXTOGMC/EXTGGFR/0,,contentMDK:21457705~pagePK:64168445~piPK:64168309~theSitePK:578069,00.html

[10] http://www.oilandgaseurasia.com/articles/p/42/article/403/

[11] http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/EXTOGMC/EXTGGFR/0,,contentMDK:20620350~menuPK:828276~pagePK:64168445~piPK:64168309~theSitePK:578069,00.html

Activities for reduction of flaring are connected to gas utilization activities (e.g. Soroosh & Nowrooz Early Gas Gathering and Utilization Project) under CDM [12].

Turkmenistan: There is no public available information on APG practices applied or relevant projects implemented in Turkmenistan. However, according to the Global Gas Flaring reduction Partnership (GGFP) Fact Sheet: First Global Satellite Survey on Gas Flaring[13], Turkmenistan is within the countries where flaring increased during the observed period 1995 – 2006. Regardless increased involvement of foreign oil companies, Turkmenistan still operates rather outdated soviet oil production facilities which foresee flaring of the associated gas.

Azerbaijan: In Azerbaijan there are two large companies operating the oil and gas fields: BP and SOCAR. Whereas high-pressure gas is recovered and transported to onshore gas processing plants, the low-pressure associated gas is mainly vented or flared at offshore installations. According to its annual Sustainability Report 2008 BP installed a flaring facility at Azeri-Chraq-Guneshli oil field, where 761 kilo tonnes of hydrocarbon where flared in 2008[14]. SOCAR's offshore production sites are equipped with rather outdated flaring and venting facilities, which enable mostly only venting of low-pressure gas. In the recent years no attempts were undertaken by oil companies in the region for effective utilization of low-pressure associated gas. The only exception is the project *Recovery and transport of the vented gas at the Guneshli oil and gas field in Azerbaijan* developed under CDM scheme. Similar to the proposed project activity the *Guneshli project* avoids venting of low-pressure associated gas. However, according to the "Tool for the assessment and demonstration of additionality" version 05.2 other CDM project activities are not to be included in the common practice analysis.

Sub-Step 4b: Discuss any similar Options that are occurring

As shown in Sub-Step 4a above, no evidence could be found for project activities similar to the proposed CDM project. Other similar CDM and JI activities developed and implemented in the region are not considered within this analysis.

Taking into consideration the results of the common practice analysis the proposed project activity is additional, as no similar activities can be observed.

Justification of identified baseline scenario

Having analysed two plausible alternative scenarios identified for the proposed CDM project activity it is concluded that the baseline scenario for Neft Dashlari and Palchiq Pilpilassi oil production sites is to continue current practice – venting of the low-pressure associated gas.

Table B.4.5: Summary of analysis of the alternative scenarios

Alternative	Legal issue	Economic attractiveness	Common practice
Alternative 1 Continuation of current practice of venting of LP APG at the oil production site, operation of the	Not prohibited by law, Venting of associated gas is subject to	Economically attractive (no capital commitment required, higher NPV)	Common practice for offshore oil production sites, beside flaring of low-

[12] http://cdm.unfccc.int/Projects/projsearch.html

[13] http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/EXTOGMC/EXTGGFR/0,,contentMDK:21457705~pagePK:64168445~piPK:64168309~theSitePK:578069,00.html

[14] BP in Azerbaijan Sustainability Report 2008 (http://www.bp.com/genericarticle.do?categoryId=9029687&contentId=7013491)

existing oil and gas infrastructure without any other significant changes, and use of gas from the same source and in the same quantity for the gas-lift system as under the project activity.	payment		pressure APG
Alternative 2 Recovery, transportation, processing of recovered gas in the existing gas processing plant and constructing the necessary infrastructure (G6 and P3), without registered as a CDM project activity, and use of gas from the same source and in the same quantity for the gas-lift system as in the baseline.	Not prohibited by law	Not attractive compared to Alternative 1 (lower NPV, higher financial risks through capital commitment) and the CDM option.	Not a common practice for offshore oil producers in the region

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

The applied methodology AM0009 version 05 provides a four step approach for identification of the baseline scenario. The methodology enables clear identification of the GHG emission sources within the project boundary, that influenced by the proposed CDM project activity. Section B.4 demonstrates that the continuation of venting low-pressure associated gas at Neft Dashlari and Palchiq Pilpilassi oil fields will continue in absence of the proposed project activity, which represents the baseline scenario. The following four-steps-approach was applied for identification of the baseline and demonstration of the project additionality:

Step 1: Identify plausible alternative scenarios
Step 2: Evaluate legal aspects
Step 3: Evaluate the economic attractiveness of alternatives
Step 4: Common practice analysis

Two alternative plausible scenarios were identified and checked for their legal conformity:

Alternative 1: Continuation of current practice of venting of the low-pressure associated gas at the oil production site (G1), operation of the existing oil and gas infrastructure without any other significant changes (P4), and use of gas from the same source and in the same quantity for the gas-lift system as under the project activity (O1).

Alternative 2: Recovery, transportation, processing of recovered gas in the existing gas processing plant and constructing the necessary infrastructure (G5 and P3), without registered as a CDM project activity, and use of gas from the same source and in the same quantity for the gas-lift system as in the baseline.

The investment and common practice analysis in Section B.4 confirmed that the Alternative 1 - *Continuation of current practice of venting the low-pressure associated gas* – is the baseline scenario, and the proposed project activity is additional to the situation that would occur in the absence of the project.

The proposed project activity reduces emissions by recovering and utilizing low-pressure associated gas which is vented in the baseline. The recovered gas displaces the use of other fossil fuel sources by end-consumers. The applied methodology AM0009 version 05 assumes that the use of recovered gas displaces the use of methane – the fossil fuel with the lowest direct CO2 emissions. Section B.6.1 below explains application of the CDM methodology for calculation of emission reductions achieved by the proposed project.

Prior consideration of the CDM

According to the Guidelines on the demonstration and assessment of prior consideration of the CDM (EB49 Annex 22) the proposed project activity is considered as an existing project activity with the start date before 2nd August 2008. Table below shows the sequence of project preparation and development activities undertaken by the project participants.

Table B.5.1: Sequence of project preparation activities	
March 2007	Letter by the Deputy Minister of Energy and Industry (**Letter of the Deputy Minister of Industry and Energy dated March 6, 2007 confirms that project at OGPD Neft Dashlari was prepared and developed under CDM.)**
2nd April 2007	Project start date (contract for construction and installation works signed)
April-October 2007	Preparation of the project idea note (PIN)
November 2007	Request to the Ministry of Environment by SOCAR for LoE
February 2008	Letter of Endorsement received
July 2008	Compressors at collector platform 2192 commissioned
April 2009	Meeting and negotiations with Gazprom Germania on the project
April – December 2009	Start of the PDD preparation incl. baseline study & additionality assessment.
May 2010	Start of validation process
October 2010- May 2012	Revision of the PDD in the process of validation.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

The project activity reduces emissions by recovering and utilizing recovered low-pressure associated gas which is currently vented. The utilization of the recovered gas displaces the use of other fossil fuel sources. Thereby a simplified and at the same time conservative calculation of emission reductions is applied in accordance with the approved CDM methodology AM0009 version 05. This methodology assumes that the use of recovered gas displaces the use of methane – the fossil fuel with the lowest direct CO_2 emissions.

As stated in the monitoring methodology, the following data are needed in order to determine the emission reductions:

- The quantity and net calorific value of recovered gas;
- The quantity and composition of fossil fuels utilized as a result of the project activity (if relevant);
- The quantity of electricity consumed as a result of the project activity (if relevant).

Hence, under AM0009 version 05 the baseline emissions are based on quantity of APG recovered. The quantity of gas produced can be directly linked to the oil production. The calculation of the ex ante baseline emissions in the PDD is based on gas production forecast. While the forecasts are used for PDD, the ex post data on the quantity and net calorific value of the recovered gas will be collected and monitored.

Description of the Project Activity

The proposed project aims on the recovery of low-pressure associated gas, and its transportation and processing in GPP for end-users. Thus the recovered gas will replace other fossil fuels at end-users. The project will install compressors at offshore collector platforms and construct new gas pipelines connecting the offshore platforms with the gathering gas pipeline for the transportation of recovered gas to the central compressor facility KS-3 and from there to the processing plant thereby replacing fossil fuels by end-users. The project activity will avoid carbon dioxide emissions that would occur from the combustion of fossil fuels at end-users.

Baseline emissions

The baseline emissions are according to AM0009 version 05 those that would occur from combustion of other fossil fuels at end-users in absence of the project activity. Project activities under this methodology reduce emissions by recovering and using low-pressure associated gas. The utilization of the recovered gas displaces the use of other fossil fuel sources. 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. The AM0009 methodology provides for 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.

The baseline emissions – the emissions from combustion of methane to meet energy demand by end-users - are quantified by measuring the quantity and the calorific value of gas recovered and transported to the GPP. The emission reduction measures implemented within the proposed CDM project will replace fossil fuel - natural gas according to the applied methodology.

The baseline is the consumption of fossil fuels (at end-users in a combustion process). Thereby it is indifferent if energy was gained or if end-user products were produced since the methodology assumes the lowest direct CO_2-emission factor of fossil fuels which is for methane. This approach is conservative and simplifies the calculation of the emission reduction.

According to AM0009 version 05 the baseline emissions are calculated as follows (Formula 1):

(1) $$BE_y = V_{F,y} \bullet NCV_{RG,F,y} \bullet EF_{CO2,methane}$$

Where:

BE_y Baseline emissions in year y, in tCO_2

$V_{F,y}$ Volume of total recovered gas measured at point F in Figure B.3.1 in year y, (Nm^3)

$NCV_{RG,F,y}$ Average net calorific value of recovered gas at point F in Figure B.3.1in year y, (TJ/Nm3)

$EF_{CO2,methane}$ CO_2 emission factor for methane, in tCO_2/TJ

For the proposed CDM project activity the Formula (1) will be applied for calculation of baseline emissions. The monitoring points are specified in Figure B.3.1.

Project emissions

The following sources of project emissions are accounted for in AM0009 version 05:

- 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 of delivery into an existing gas processing plant (up to point F in Figure 2 in AM0009);
- 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 of delivery into an existing gas processing plant (up to point F, Figure 2 in AM0009).
- There are two sources of CO2 emissions in the project. First, new compressors NQK-7/1-5 installed at the offshore collector platforms are powered by electricity delivered from the offshore gas-turbine power plant. This power plant is fueled by high-pressure associated gas. Emissions due to the electricity consumption represent, thus, the first source of GHG emissions. Second, at the central compressor facility KS-3 of OGPD Neft Dashlari the compressors 10GCNAM are powered by low associated gas. 10GCNAMcompressors are operated on APG with a pressure level ranging from 0.313 to 0.323 MPa. The associated gas consumption by the compressors is the second GHG emission source.

<u>CO_2 emissions due to consumption of fossil fuels</u>

The central compressor facility of OGPD Neft Dashlari (KS-3) was included in the project boundary as a source of the project emissions. The operational compressors 10GCNAM are used by the project activity for transportation of the recovered gas to GPP. These compressors operate at low pressure APG, which is a fossil fuel. Hence, CO_2 emissions have to be accounted due to consumption of high-pressure associated gas by the central compressor facility KS-3.

<u>CO_2 emissions due to the use of electricity</u>

The compressors to be installed at offshore collector platforms under the project activity consume electricity for their operations. Following the methodology AM0009 version 05 the project emissions occur due to electricity use for gas recovery, pre-treatment and transportation. Electricity will be consumed by the proposed project activity for:

- Compression of the low-pressure associated gas at the offshore collector platforms, and its transportation to the central compressor facility KS-3 through the gathering gas pipeline. The new compressors are powered by electricity delivered from the offshore gas-turbine power plant. This power plant is fueled by high-pressure associated gas. Emissions due to the use of electricity represent the source of GHG emissions.

Based on the said above regarding sources of project emissions relevant to the proposed project activity, the following sources of emissions are identified:

- CO_2 emissions due to consumption of fossil fuels for compression the recovered gas at the central compressor facility KS-3;
- CO2 emissions due to the use of electricity for compression and transportation of the recovered gas up to the central compressor facility KS-3.

According to AM0009 version 05 the project emissions are calculated as follows:

(2) $$PE_y = PE_{CO2,fossil\ fuels,y} + PE_{CO2,elec,y}$$

Where:

PE_y	Project emissions in year y, (tCO2e)
$PE_{CO2,fossilfuels,y}$	CO2 emissions due to consumption of fossil fuels for the recovery, pre-treatment, transportationand, if applicable, compression of the recovered gas up to the point F in Figure 2 in the year y, (tCO2e);
$PE_{CO2,elec,y}$	CO_2 emissions due to the use of electricity for pre-treatment and compression of the recovered gas up to the point of on-site use in the oil heaters and the power station in the year y, (tCO2e).

The CO_2 emissions due to combustion of fossil fuels and the use of electricity will be calculated according to the methodological tools:

- Tool to calculate baseline, project and/or leakage emissions from electricity consumption, version 01;
- Tool to calculate project or leakage CO2 emissions from fossil fuel combustion, version 02.

The formula below will be applied for calculation of CO2 emissions due to fossil fuel combustion:

$$PE_{CO2,fossil\ fuels,y} = \sum_i FC_{i,j,y} \bullet COEF_{i,y}$$

Where:

$PE_{CO2,fossilfuels,y}$	CO_2 emissions due to consumption of fossil fuels for the compression and transportation in year *y*, (tCO2e);
$FC_{i,j,y}$	Quantity of fuel type i combusted in process *j* in year *y* (Nm3);
$COEF_{i,y}$	CO_2 emission coefficient of fuel type *i* in year *y* (tCO2/Nm3);
i	Fuel types combusted in process *j* in year *y*

For calculation of CO2 emissions due to electricity consumption Formula below is applied:

$$PE_{CO2,elec,y} = \sum_i EC_{PJ,j,y} \bullet EF_{EL,j,y} \bullet (1 + TDL_{j,y})$$

Where:

$PE_{CO2,elec,y}$	CO_2 emissions due to the use of electricity for compression and transportation of the recovered gas up to the central compressor facility KS-3 during the period *y*, (tCO2e);
$EC_{PJ,j,y}$	Quantity of electricity consumed by the project electricity consumption source J in year *y* (MWh/yr);
$EF_{EL,j,y}$	Emission factor for electricity generation for source *j* in year *y* (tCO2/MWh);
$TDL_{j,y}$	Average technical transmission and distribution losses for providing electricity to source *j* in year *y*
j	Sources of electricity consumption in the project

Leakage

Leakage emission is calculated as follows:

(3)

Where:

LE_y	Leakage emissions in year y (tCO2e)

$LE_{FC,y}$ Leakage emissions due to fossil fuel consumption after point F in figure 2 in year *y* (tCO2e)

$LE_{EC,y}$ Leakage emissions due to electricity consumption after point F in figure 2 in year y (tCO2e)The CDM EB did clarify in the course of the revision of AM 009 (Version 6.0) that leakge shall only be considered for those projects which involve CNG in its production and transportation processes.

The proposed project delivers the recovered gas to the Gadang Gas Processing Plant where LPG and dry gas is produced. The dry gas is fed directly into the gas pipeline. Hence leakage is not considered.

GHG emission reductions

According to AM0009 version 05 the emission reductions are calculated as follows:

$$ER_y = BE_y - PE_y - LE_y \quad (4)$$

Where:

ERy Emission reductions in year y, (t CO2e)

BEy Baseline emissions in year y, (t CO2e)

PEy Project emissions in year y, (t CO2e)

LEy Leakage emissions inyear y, (t CO2e)

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

Data / Parameter 1[15]:	$EF_{CO2,methane}$
Data unit:	tCO_2/TJ
Description:	CO2 emission factor for methane
Source of data used:	Approved methodology AM0009 version 05
Value applied:	49.55 tCO2/TJ
Justification of the choice of data or description of measurement methods and procedures actually applied :	The Energy Information Administration (EIA), Department of Energy, USA <http://www.eia.doe.gov/oiaf/1605/coefficients.html> presents the default emission factor of 115.258 pounds of CO2 per million BTU.
Any comment:	The Parameter is used for calculation in Equitation 1.

Data / Parameter 2[5]:	T_x
Data unit:	hours/year
Description:	Annual operating hours for plant/equipment
Source of data used:	Assumption by project participants
Value applied:	8,760 hours/year
Justification of the choice of data or description of measurement methods and procedures actually	Conservative assumption (full load operating hours) This parameter is used when determining the quantity of electricity consumed by the project electricity consumption source j in year y ($EC_{PJ,j,y}$) under the Tool to calculate baseline, project and/or leakage emissions from electricity consumption, Version 01.

[15] The same number of the parameter is used in Section B.7.1.

applied :	
Any comment:	-

Data / Parameter 3[5]:	*TDL* $_{j,y}$
Data unit:	-
Description:	Average technical transmission and distribution losses for providing electricity to source j in year y
Source of data used:	Tool to calculate baseline, project and/or leakage emissions from electricity consumption, version 01.
Value applied:	0
Justification of the choice of data or description of measurement methods and procedures actually applied :	In case of scenario B assume TDLj,y = 0 as a simplification according to the Tool to calculate baseline, project and/or leakage emissions from electricity consumption, Version 01 This parameter is used when determining the emission factor for electricity generation for source j in the year y ($FE_{EL,j,y}$) under the Tool to calculate baseline, project and/or leakage emissions from electricity consumption, Version 01.
Any comment:	-

Data / Parameter 4[5]:	*k*
Data unit:	-
Description:	Gas consumption rate for transportation of one cubic meter gas by compressors
Source of data used:	Technical specification of the compressor type 10GCNAM2/5-55 installed at the central compressor station
Value applied:	0.075
Justification of the choice of data or description of measurement methods and procedures actually applied :	Following the technical specifications of 10GCNAM2/5-55 specify the following: ▪ At full load, the compressor may compress 10,800 m3/ha (page 16) ▪ At full load, the compressor features an energy demand of 1,177kW (page 16). Based on the APG's NCV (36.92 MJ/m3), the energy demand amounts to 0.011 m3 APG per m3 APG compressed. Still the proposed project applies a higher value. This value was determined in cooperation with the SOCAR's chief engineer. The value was determined by dividing ▪ the compressor's maximum gas consumption by ▪ the maximum quantity of gas transported by the compressor per day. Eventually the compressor may consume more energy (m3 APG per m3 APG transported) as listed in the technical specifications, if not under full load. Using the two maximum values to determine *k*, results in the highest, possible energy consumption parameter. This value amounts to 693% of the default value listed in the technical specification. This conservative value is subsequently applied to determine the project emissions. This parameter is used when determining the quantity of fuel type i combusted in process j during year y ($FC_{i,j,y}$) using the Tool to calculate project or leakage emissions from fossil fuel combustion, Version 02.
Any comment:	-

Data / Parameter 5[5]:	P_J
Data unit:	kW
Description:	Input capacity of electricity consumption source J
Source of data used:	Technical specification of the compressor type NQK-7/1-5 installed by the project at the offshore collector platforms
Value applied:	75
Justification of the choice of data or description of measurement methods and procedures actually applied :	Input capacity of NQK-7/1-5 compressor installed at the project sites. The value is indicated on the tag at the compressor onsite and in the technical specification. This parameter is used when determining the quantity of electricity consumed by the project electricity consumption source j in year y ($EC_{PJ,j,y}$) under the Tool to calculate baseline, project and/or leakage emissions from electricity consumption, Version 01.
Any comment:	-

B.6.3. Ex-ante calculation of emission reductions:

Following the discussion in B.6.1 for estimation of emissions reductions the ex-ante baseline and project emissions are determined.

Baseline emissions

The ex-ante baseline emissions are calculated applying Formula 1 presented in B.6.1.:

(1) $$BE_y = V_{F,y} \bullet NCV_{RG,F,y} \bullet EF_{CO2,methane}$$

Where:

BE_y Baseline emissions during year y, in tCO_2

$V_{F,y}$ Volume of total recovered gas measured at point F in Figure B.3.1., during year y, (Nm^3)

$NCV_{RG,F,y}$ Average net calorific value of recovered gas measured at point F in Figure B.3.1., in year y, (TJ/Nm3)

$EF_{CO2,methane}$ CO_2 emission factor for methane, in tCO_2/TJ

The proposed project shall be implemented stepwise. Thus, the quantity of recovered gas follows not only the gas production forecast, but also the project implementation plan. The project will become fully operational in the first quarter 2010, after commissioning the facilities. Based on ex-ante estimates of the gas production potential and the net calorific values measured at the project sites, the baseline emissions are estimated as follows:

Table B.6.3.1. Estimated baseline emissions over the first crediting period 2013-2022

Period Y	Volume of recovered gas, Nm^3 $V_{F,y}$	Net calorific value, TJ/Nm^3 $NCV_{RG,F,y}$	CO2 emission factor for CH4, tCO_2/TJ $EF_{CO2,\,methane}$	Baseline emissions, tCO_2 BE_y
2013	171,891,082	0.000036918	49.55	314,437
2014	163,984,093	0.000036918	49.55	299,973

2015	156,440,824	0.000036918	49.55	286,174
2016	149,244,546	0.000036918	49.55	273,010
2017	142,379,297	0.000036918	49.55	260,452
2018	135,829,850	0.000036918	49.55	248,471
2019	129,581,676	0.000036918	49.55	237,041
2020	123,620,919	0.000036918	49.55	226,137
2021	117,934,357	0.000036918	49.55	215,735
2022	112,509,377	0.000036918	49.55	205,811
Total 2013-2022	1,403,416,022	-		2,567,241

Project emissions

The ex-ante calculation of project emissions comprises both identified sources 1) CO_2 emissions due to consumption of fossil fuels for compression the recovered gas at the central compressor station; 2) CO_2 emissions due to the use of electricity for compression and transportation of the recovered gas up to the central compressor station. Formula 2 is applied accordingly:

(2) $$PE_y = PE_{CO2,fossil\ fuels,y} + PE_{CO2,elec,y}$$

Where:

PE_y	Project emissions in year y, (tCO2e)
$PE_{CO2,fossilfuels,y}$	CO_2 emissions due to consumption of fossil fuels for the recovery, pre-treatment, transportation in year y, (tCO2e);
$PE_{CO2,elec,y}$	CO_2 emissions due to the use of electricity for pre-treatment and compression of the recovered gas up to the point of on-site use in the oil heaters and the power station in year y, (tCO2e).

CO_2 emissions due to fossil fuel combustion are determined according to Formula below:

$$PE_{CO2,fossil\ fuels,y} = \sum_i FC_{i,j,y} \bullet COEF_{i,y}$$

Where:

$PE_{CO2,fossilfuels,y}$	CO_2 emissions due to consumption of fossil fuels for the compression and transportation in year *y*, (tCO2e);
$FC_{i,j,y}$	Quantity of fuel type i combusted in process *j* during the year *y* (Nm3);
$COEF_{i,y}$	CO_2 emission coefficient of fuel type *i* in year *y* (tCO2/Nm3);
i	Fuel types combusted in process *j* during the year *y*

The recovered gas compression in 10GCNAM2/5-55 compressors at the central hub represents the process *j*. There are no other processes demanding fossil fuels for combustion within the project boundary. The compressed associated gas is the fossil fuel type *i* combusted in the process *j*.
As of Option A of the methodological *Tool to calculate project or leakage CO2 emissions from fossil fuel combustion, version 02*:

$$COEF_{i,y} = w_{C,i,y} * \rho_{i,y} * 44/12$$

Where:

$COEF_{i,y}$	CO_2 emission coefficient of fuel type *i* in year *y* (tCO2/Nm3);
$w_{C,i,y}$	Weighted average mass fraction of carbon in fuel type i in year y (tC/t)
$\rho_{i,y}$	Weighted average density of fuel type i in year y (t/Nm3)
i	Fuel types combusted in process *j* during the year *y*

The CO_2 emission coefficient is calculated based on the chemical composition of the associated gas. The quantity of fossil fuel consumed by the project activity is determined based on maximum gas consumption rate per cubic meter of compressed gas. This rate is calculated based on the parameters presented in the technical specification of the compressors 10GCNAM/25-50. The most conservative consumption rate is assumed for calculation of the project emissions.

$$FC_{i,y} = V_{F,y} * k_{i,y}$$

Where:

$FC_{i,y}$	Quantity of fuel type i combusted in process *j* during the year *y* (Nm3);
$V_{F,y}$	Volume of total recovered gas measured at point F in Figure B.3.1., in year y, (Nm³)
$k_{i,y}$	Gas consumption rate for transportation of one cubic meter of gas by compressors;
i	Fuel types combusted in process *j* during the year *y*

Table B.6.3.2. CO2 emissions due to fossil fuel consumption 2013 - 2022

Period **y**	**Quantity of associated gas combusted, 1000Nm3** $FC_{i,j,y}$	**CO_2 emission coefficient of fuel type *i* in year *y*, tCO2/Nm3** $COEF_{i,y}$	**CO2 Emissions from fossil fuel combustion, tCO2/y** $PE_{fc,j,y}$
2013	12,891.83	0.00171	22,055
2014	12,298.81	0.00171	21,040
2015	11,733.06	0.00171	20,072
2016	11,193.34	0.00171	19,149
2017	10,678.45	0.00171	18,268
2018	10,187.24	0.00171	17,428
2019	9,718.63	0.00171	16,626
2020	9,271.57	0.00171	15,861
2021	8,845.08	0.00171	15,132
2022	8,438.20	0.00171	14,436
Total 2013-2022	105,256.20	-	180,068

For calculation of CO2 emissions due to electricity consumption Formulae 4 is applied:

$$PE_{CO2,elec,y} = \sum EC_{PJ,j,y} \bullet EF_{EL,j,y} \bullet (1 + TDL_{j,y})_{i}$$

Where:

$PE_{CO2,elec,y}$	CO_2 emissions due to the use of electricity for compression and transportation of the recovered gas up to the central compressor station in year *y*, (tCO2e);
$EC_{PJ,J,y}$	Quantity of electricity consumed by the project electricity consumption source *J* in year *y* (MWh/yr);

$EF_{EL,J,y}$	Emission factor for electricity generation for source *J* in year *y* (tCO2/MWh);
$TDL_{J,y}$	Average technical transmission and distribution losses for providing electricity to source *J* in year *y*
J	Sources of electricity consumption in the project

There is one electricity consumption source *J* within the proposed CDM activity, which is an onsite compressor NQK. According to the specification of the identified electricity consumption source – the on-site compressor NQK-7/1-5 NQK-7/1-5- the annual quantity of electricity to be consumed is identified by multiplying the annual operating hours by a number of NQK-7/1-5 NQK-7/1-5compressors in operation during the reference period, and the input capacity of NQK-7/1-5 NQK-7/1-5 compressors. For calculation of ex-ante CO2 emissions from electricity consumption the project implementation plan was taken into consideration for determination of a number of the onsite compressors in operation. Table B.6.3.3 shows a number of NQK-7/1-5 NQK-7/1-5 compressors in operation according to the implementation plan.

Table B.6.3.3. Electricity consumption sources

No	Project site	Number of NQK-7/1-5 NQK-7/1-5 units installed	Input capacity per unit	Units in operation	Input capacity in total	Operational hours per year	Annual electricity consumption
		number	kW	number	kW	hours	MWh/y
1	2192	5	75	3	225	8,760	1,971.00
2	1517	8	75	6	450	8,760	3,942.00
3	741a	5	75	3	225	8,760	1,971.00
4	2346	9	75	7	525	8,760	4,599.00
5	1005a	2	75	2	150	8,760	1,314.00
6	1201	10	75	9	675	8,760	5,913.00
7	1799	6	75	2	150	8,760	1,314.00
8	810	4	75	4	300	8,760	2,628.00
TOTAL		**49**		**36**			**23.652,00**

According to the methodological *Tool to calculate baseline, project and/or leakage emissions from electricity consumption, version 01*, the Scenario B applies for the proposed CDM project activity: Electricity consumption from an off-grid fossil fuel fired captive power plant. The offshore gas-turbine power plant operated by OGPD Neft Dashlari is the only power supplier for the identified electricity consumption source. The emission factor for electricity generation for the gas-turbine power plant is determined accordingly:

$$EF_{EL,j,y} = \sum_{n} \sum_{I} FC_{n,i,y} \bullet NCV_{i,y} \bullet EF_{CO2,i,y} / \sum_{n} EG_{n,y}$$

Where:

$EF_{EL,j,y}$	Emission factor for electricity generation for source *J* in year *y* (tCO2/MWh);
$FC_{n,i,y}$	Quantity of fossil fuel type i fired in the captive power plant n in year y (Nm3)
$NCV_{i,y}$	Average net calorific value of fossil fuel type i used in year y, (GJ/Nm3)
$EF_{CO2,i,y}$	Average CO2 emission factor of fossil fuel type i used in year y (tCO2/GJ)
$EG_{n,y}$	Quantity of electricity generated in captive power plant n in year y (MWh)
i	Fossil fuel types fired in captive power plant n in year y

The captive power plant is fueled by the high-pressure associated gas. For ex-ante calculations the measured quantity of this fossil fuel and the measured quantity of electricity generated during the year 2008 were taken into consideration.
The average CO2 emission factor is calculated using a parameter calculated according to the *Tool to calculate project or leakage CO2 emissions from fossil fuel combustion, version 02*, and the given net calorific value of the associated gas. Formula X applies accordingly:

$$EF_{CO2,i,y} = COEF\ i,y\ /\ NCV\ i,y$$

Where:

$EF_{CO2,i,y}$	Average CO2 emission factor of fossil fuel type i used in year y (tCO2/GJ)
$COEF_{i,y}$	CO_2 emission coefficient of fuel type *i* in year *y* (tCO2/Nm3);
$NCV_{i,y}$	Average net calorific value of fossil fuel type i used in year y, (GJ/Nm3)
i	Fossil fuel types fired in captive power plant n in year y

Table B.6.3.4. CO2 emissions due to electricity consumption 2013-2022

Period	Quantity of electricity consumed by the project, MWh/y	CO2 emission factor for electricity generation, tCO2/MWh	CO2 emissions from electricity consumption, tCO2/y
y	$EC_{PJ,j,y}$	$EF_{EL,j,y}$	$PE_{EC,j,y}$
2013	23,652.00	0.85234	20,160
2014	23,652.00	0.85234	20,160
2015	23,652.00	0.85234	20,160
2016	23,652.00	0.85234	20,160
2017	23,652.00	0.85234	20,160
2018	23,652.00	0.85234	20,160
2019	23,652.00	0.85234	20,160
2020	23,652.00	0.85234	20,160
2021	23,652.00	0.85234	20,160
2022	23,652.00	0.85234	20,160
Total 2013-2022	**236,520.00**	**-**	**201,595**

The ex-ante project emissions are determined in Table B.6.3.5 below.

Table B.6.3.5. Project emissions over 2013-2022

Period	CO2 Emissions from fossil fuel combustion, tCO2/y	CO2 emissions from electricity consumption, tCO2/y	Project emissions, tCO2/y
y	$PE_{fc,j,y}$	$PE_{EC,j,y}$	PE_{y}
2013	22,055	20,160	42,214
2014	21,040	20,160	41,200
2015	20,072	20,160	40,232

2016	19,149	20,160	39,309
2017	18,268	20,160	38,428
2018	17,428	20,160	37,587
2019	16,626	20,160	36,786
2020	15,861	20,160	36,021
2021	15,132	20,160	35,291
2022	14,436	20,160	34,595
Total 2013-2022	180,068	201,595	381,664

Leakage

Leakage emission is calculated as follows:

(3)

Where:

LEy	Leakage emissions in year y (tCO2e)
$LE_{FC,y}$	Leakage emissions due to fossil fuel consumption after point F in figure 2 in year *y* (tCO2e)
$LE_{EC,y}$	Leakage emissions due to electricity consumption after point F in figure 2 in year y (tCO2e)

The CDM EB did clarify in the course of the revision of AM 009 (Version 6.0) that leakge shall only be considered for those projects which involve CNG in its production and transportation processes.
The proposed project delivers the recovered gas to the Gadang Gas Processing Plant where LPG and dry gas is produced. The dry gas is fed directly into the gas pipeline. Hence leakage is not considered.

Emission reductions

Having determined the baseline emissions and the project emissions the emission reductions are calculated according to Formula 5:

(4) $$ER_y = BE_y - PE_y - LE_y$$

Where:

ER_y	Emission reductions in year y, tCO2
BEy	Baseline emissions in year y, in tCO2
PE_y	Project emissions in year y, tCO2

The calculation results are presented in Section B.6.4.

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

Table B.6.4. Summary of the ex ante estimation of emission reductions for the crediting period 2013-2022

Year	Estimation of project activity emissions	Estimation of baseline emissions	Estimation of leakage	Estimation of overall emission reductions

	(tonnes of CO_{2e})	(tonnes of CO_{2e})	(tonnes of CO_{2e})	(tonnes of CO_{2e})
2013	42,214	314,437	0	272,223
2014	41,200	299,973	0	258,773
2015	40,232	286,174	0	245,942
2016	39,309	273,010	0	233,701
2017	38,428	260,452	0	222,024
2018	37,587	248,471	0	210,883
2019	36,786	237,041	0	200,255
2020	36,021	226,137	0	190,116
2021	35,291	215,735	0	180,444
2022	34,595	205,811	0	171,216
Total (tonnes of CO_{2e})	**381,664**	**2,567,241**	**0**	**2,185,577**

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

The project monitoring plan is developed based on the approved CDM methodology AM0009 version 05. Applicability of the selected baseline and monitoring methodology is demonstrated in B.2. This methodology provides for a very straightforward and conservative and simplified calculation of emission reductions. Through the conservative assumptions made in this methodology a number of monitoring parameters is reduced.
All project relevant parameters within the project boundary will be monitored according to the procedures specified in this PDD.

B.7.1 Data and parameters monitored:

Data / Parameter 1:	$V_{F,y}$
Data unit:	Nm^3
Description:	Volume of the total recovered gas measured at point F in Figure B.3.1., in year y
Source of data to be used:	Measurement by the project participants: Gas flow meters
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Year / Gas volume, Nm^3: 2013: 171,891,082 2014: 163,984,093 2015: 156,440,824 2016: 149,244,546 2017: 142,379,297 2018: 135,829,850 2019: 129,581,676 2020: 123,620,919 2021: 117,934,357 2022: 112,509,377
Description of measurement methods and procedures to be	Volume of gas shall be completely metered with regular calibration of metering equipment (gas flow meters). Based on continuous metering the daily reports will be aggregated on the project sites. The parameter will be monitored for

applied:	each of the project sites continuously, and reported and archived by the project manager monthly.
QA/QC procedures to be applied:	The metering equipment is calibrated according to the host country requirements and relevant industry standards. The data will be archived in paper and electronic form.
Any comment:	-

Data / Parameter 2:	$NCV_{RG,F,y}$
Data unit:	TJ/Nm^3
Description:	Net calorific value of recovered gas measured in year y at point F in Figure B.3.1.
Source of data to be used:	Measurement by the project participants in a certified laboratory.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.00003692
Description of measurement methods and procedures to be applied:	Measurements shall be undertaken monthly by laboratories in line with national or international fuel standards. Gas samples taken onsite shall be analyzed by chromatography equipment in laboratories.
QA/QC procedures to be applied:	The laboratories performing NCV measurements should have ISO17025 accreditation or justify that they can comply with similar quality standards.
Any comment:	

Data / Parameter 3:	$FC_{i,j,y}$
Data unit:	Nm^3
Description:	Quantity of fuel type i (low pressure gas) combusted in process j (fuelling the compressors) during the year y
Source of data to be used:	Measurement by the project participants
Value of data applied for the purpose of calculating expected emission reductions in section B.5	(see table below)
Description of measurement methods and procedures to be	The parameter is calculated by multiplying the quantity of total recovered gas ($V_{F,y}$) by the gas consumption rate for transportation of one cubic meter gas ($k_{i,y}$) applying Formula 7. Determination of the parameter is based on continuous

Year	Gas volume, Nm^3
2013	12,891.83
2014	12,298.81
2015	11,733.06
2016	11,193.34
2017	10,678.45
2018	10,187.24
2019	9,718.63
2020	9,271.57
2021	8,845.08
2022	8,438.20

applied:	measurement of the recovered gas volume.
QA/QC procedures to be applied:	The consistency of data should be cross-checked with gas consumption and transportation balance at the central compressor station (SKS-1, KS-3, KS-4) of OGPD Neft Dashlari.
Any comment:	-

Data / Parameter 4:	$EC_{PJ,J,y}$
Data unit:	MWh
Description:	Quantity of electricity consumed by the project electricity consumption source J (fuelling the NQK-compressors) in year y
Source of data to be used:	Calculated based on amount of operating NQK compressors $N_{J,y}$ and the maximum electricity consumed per NQK compressor.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	see table below
Description of measurement methods and procedures to be applied:	This parameter is determined conservatively by multiplying the maximum annual operating hours (T) (i.e. 8760) by the total input capacity of NQK-compressors in operation ($N_J * P_J$). The onsite operators monitor the NQK-compressors in operation continuously. The monthly reports are prepared based on daily records on NQK-compressors in operation.
QA/QC procedures to be applied:	Cross-checks with electricity consumption reports of the respective offshore collector platforms. Cross-checks with onsite operation logs for indication of compressors in operation.
Any comment:	

Year	Electricity consumed, MWh
2013	23,652.00
2014	23,652.00
2015	23,652.00
2016	23,652.00
2017	23,652.00
2018	23,652.00
2019	23,652.00
2020	23,652.00
2021	23,652.00
2022	23,652.00

Data / Parameter 5:	$w_{C,i,y}$
Data unit:	tC/t
Description:	Weighted average mass fraction of carbon in fuel type i ("high" pressure gas) in year y
Source of data to be used:	Measurements by project participants: gas composition analysis
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.689
Description of measurement methods	The parameter is calculated based on the results of gas chromatography. Measurements shall be undertaken in line with national or international fuel

and procedures to be applied:	standards. The parameter is determined monthly.
QA/QC procedures to be applied:	The laboratory performing gas chromatography is accredited according to ISO17025 accreditation or justifies that it can comply with similar quality standards.
Any comment:	

Data / Parameter 6:	$\rho_{i,y}$
Data unit:	t/Nm3
Description:	Weighted average density of fuel type i (“high” pressure gas) in year y
Source of data to be used:	Measurements by project participants: gas composition analysis
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.000677
Description of measurement methods and procedures to be applied:	The parameter is calculated based on the results of gas chromatography. Measurements shall be undertaken in line with national or international fuel standards. The parameter is determined monthly.
QA/QC procedures to be applied:	The laboratory performing gas chromatography is accredited according to ISO17025 accreditation or justifies that it can comply with similar quality standards.
Any comment:	

Data / Parameter 7:	***COEFi,y***
Data unit:	tCO2/Nm3
Description:	CO2 emission coefficient of fuel type i in year y
Source of data to be used:	Calculated based on the measured values of $w_{C,i,y}$ and $\rho_{i,y}$ according to the “Tool to calculate project or leakage CO2 emissions from fossil fuel combustion” Version 02.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.00171
Description of measurement methods and procedures to be applied:	The parameter will be calculated monthly by the project manager using the measured values of the weighted average density of fuel ($\rho_{i,y}$)and weighted average mass ($w_{C,i,}$) according to the “Tool to calculate project or leakage CO2 emissions from fossil fuel” Version 02.
QA/QC procedures to be applied:	The parameter is calculated on the basis of the values that are determined in an accredited laboratory.
Any comment:	

Data / Parameter 8:	$FC_{n,i,y}$
Data unit:	Nm3
Description:	Quantity of fossil fuel type i (high pressure gas) fired in the captive on-site Gas

	Turbine Power Plant (4 times 12MW installed capacity) in year y
Source of data to be used:	Measurements by project participants: meters of the gas-turbine power plant Historical data (records / onsite measurements) is applied for ex-ante calculation of the project emissions.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	44,552,027.02
Description of measurement methods and procedures to be applied:	Continuous measurement of fuel consumption quantities by gas-flow meters. The data is aggregated annually in reports.
QA/QC procedures to be applied:	Cross-check with the quantity of electricity generated during the reference period
Any comment:	-

Data / Parameter 9:	$EG_{n,y}$
Data unit:	MWh
Description:	Quantity of electricity generated in captive on-site Gas Turbine Power Plant (4 times 12MW installed capacity) in year y
Source of data to be used:	Measurements by project participants: meters of the gas-turbine power plant Historical data from 2008 (records / onsite measurements) is applied for ex-ante calculation of the project emissions.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	89,422
Description of measurement methods and procedures to be applied:	Continuous measurement by the onsite meters. The data is aggregated annually in reports.
QA/QC procedures to be applied:	Cross-check with the quantity of fuel used in the power plant during the reference period.
Any comment:	

Data / Parameter 10:	$NCV_{i,y}$
Data unit:	GJ/Nm3
Description:	Average net calorific value of fossil fuel type i in year y
Source of data to be used:	Measured by project participants
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0,036918
Description of measurement methods	The parameter is calculated based on the gas quality analysis conducted by the accredited laboratory and in line with national fuel standards. The fossil fuel type

and procedures to be applied:	i - associated gas - is sampled quarterly at the inlet in the gas-turbine power plant. The parameter is determined quarterly.
QA/QC procedures to be applied:	The laboratories conduction NCV calculations and gas analysis are accredited according to ISO17025 or comply with similar quality standards.
Any comment:	

Data / Parameter 11	$N_{J,y}$
Data unit:	-
Description:	Number of electricity consumption sources J (NQK-compressors) operational in year y
Source of data to be used:	Measurements by project participants
Value of data applied for the purpose of calculating expected emission reductions in section B.5	36
Description of measurement methods and procedures to be applied:	The project operator makes daily records on compressors NQK-7/1-5 in operation. Monthly reports are delivered to the technical specialist responsible for the project monitoring. The data from the monthly reports is aggregated in the annual monitoring reports.
QA/QC procedures to be applied:	The compressors NQK-7/1-5 are operated according to the national industrial standards. Regular periodic technical inspections by authorized bodies are conducted. Cross-checks with special event logs and technical logs onsite in regard to the operation of the compressors NQK-7/1-5.
Any comment:	

B.7.2. Description of the monitoring plan:

Allocation of the project management responsibility

The management and operation of the CDM project is carried out by SOCAR (the project operator). It is the key responsibility of the project operator to ensure credibility of the project through accurate and systematic monitoring of project operations and reporting on emission reductions achieved.

The operator shall appoint a technical manager, who will be responsible for data collection, preparation of monitoring reports and calculation of emission reductions. The responsible technical manager will have the overall responsibility for preparation of the monitoring report, coordinating data collection from each of the project sites. The project operator will sign all official reports, GHG emission reduction protocols and worksheets. This will confirm that the official documentation is kept on record.

The project operator is responsible for development and implementation of the internal procedures for monitoring of emission reductions achieved by the project activity. All departments relevant for the monitoring process will receive clear instructions for completion of the monitoring requirements. The initial project validation will assess either the proposed monitoring procedures are satisfactory for verification of emission reductions. Table B.7.2.1 presents the initial distribution of responsibilities.

Table B.7.2.1.: Distribution of responsibilities within the monitoring process	
Responsible Staff	**Area of responsibility**
Operational staff at the project sites	• Archiving and reporting the data metered by gas flow meters; • Archiving and reporting the data on NQK-7/1-5 NQK-7/1-5 compressors in operation; • Records on special events (special event log); • Attending sampling of the recovered gas by the laboratory staff.
Operational staff at the gas-turbine power plant	• Archiving and reporting the data metered by gas flow meters at entry into power plant; • Archiving and reporting the metered data on electricity generation; • Attending sampling of the delivered gas conducted by the laboratory staff.
Technical Specialist of OGPD Neft Dashlari	• Collection and archiving of the data submitted by operational staff at the project sites and at the gas-turbine power plant; • Supervision of periodic calibration of all meters involved in the project, • Supervision of internal and external technical inspections of the compressors involved in the project activity (according to the national industry standards); • Preparation of monthly monitoring reports and their submission to the technical manager of the Ecology Department.
Technical manager, Ecology Department of SOCAR	• Collection and archiving of the data submitted by the laboratory and the technical specialist of OGPD Neft Dashlari • Regular training of the operational staff involved in the monitoring process; • Preparation and if required adaptation of the internal monitoring procedures and instructions; • Preparation of the internal monthly monitoring reports; • Preparation of the annual monitoring reports for the project verification.
Gas analysis specialists, Laboratory of SOCAR	• Periodic sampling of the recovered gas at the project sites and the fuel gas delivered to the gas turbine power plant; • Analysis of gas composition including determination of the net calorific value and the gas density; • Archiving and reporting the determined values to the Technical Manager of the SOCAR’s Ecology Department of SOCAR; • Submitting the copies of valid accreditation certificates to the Technical Manager of the SOCAR’s Ecology Department.

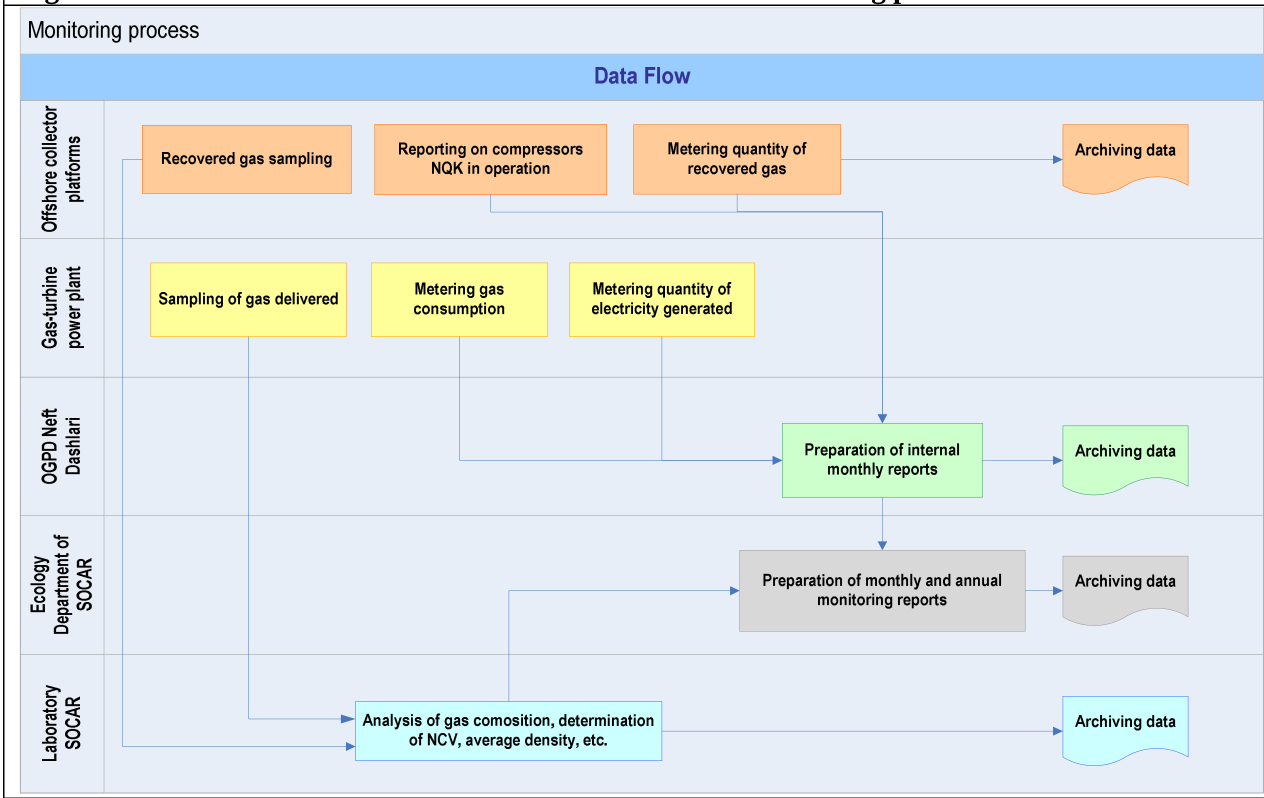
Data handling

Data to be collected for the purpose of the project monitoring includes parameters described in B.7.1. The responsible technical manager will assure that the data is collected as required. The collected data will be kept both in a paper and electronic form. For electronic data copies regular backups will be conducted. Frequency of the data collection is stated in B.7.1. A monthly internal report will be prepared based on the excel worksheet by the responsible technical manager. These monthly reports will be used for quality assurance when compared with the annual data reported by each of the project sites.
The data collected for the purpose of the project monitoring shall be kept at least for 2 years after the end of the crediting period.

Reporting

Besides internal monthly reports the project operator will prepare periodic reports as needed for audits and verification purposes. The annual reports will include information on the overall project performance, baseline emissions, and emission reductions achieved, compliance of achievements with environmental and social targets, methods of calculation, relevant references to the data sources, description of internal monitoring procedures. Figure B.7.2.1. shows the data flows within the project monitoring process. Precise instructions and requirements for data submission will be developed by the responsible technical manager.

Figure B.7.2.1. Schematic illustration of data flows within monitoring process



Quality assurance and control procedures

Quality is assured and controlled by appointing a competent technical manager, who will be responsible for internal monitoring processes and for transparency of reports and records. Metering of associated gas volumes should be carried out automatically by calibrated flow meters and operated according to the requirements stated in the technical specification. Periodic state inspection of meters and compressor facilities by appropriate institutions further insures a correct handling of monitoring units. The detailed quality assurance and quality control activities are listed for individual parameters in Section 7.1.

Training of staff involved in monitoring process

In order to assure an appropriate preparation of the monitoring reports and the CDM project operations the project participants shall introduce regular trainings for staff involved in the monitoring process. The project participants are to organize an external training by international CDM experts, who will introduce the best practices for preparation of monitoring reports. Additionally, the project operator will regularly organize internal trainings for operational staff involved in the monitoring. Based on the outcomes of these trainings the internal procedures and instructions shall be adapted.

The detailed monitoring plan is attached in Annex 4.

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

The baseline study and the monitoring methodology are completed on 30th October 2009.
The study has been prepared by Ksenia Brockmann, GFA ENVEST GmbH, Eulenkrugstr. 82, 22359 Hamburg, Germany. Neither Ksenia Brockmann nor GFA ENVEST GmbH is a project participant for the proposed projects.

SECTION C. Duration of the project activity / crediting period

C.1. Duration of the project activity:

C.1.1. Starting date of the project activity:

The project start date is 2nd April 2007. This is the date when the contract for construction and installation has been signed by SOCAR.

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

Taking into consideration the oil and gas production forecast for upcoming years the operational lifetime of the proposed project is 15 years or 180 months.

C.2. Choice of the crediting period and related information:

The project participants have selected a fixed crediting period for the proposed project activity. Accordingly under this option the length and starting date of the period is determined once for a project activity with no possibility of renewal or extension once the project activity has been registered.

C.2.1. Renewable crediting period:

C.2.1.1. Starting date of the first crediting period:

n/a

C.2.1.2. Length of the first crediting period:

n/a

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

01/01/2013 or whichever date later after registration of the proposed CDM project activity.

C.2.2.2. Length:

According to the paragraph 49 (b) of CDM modalities and procedures the maximum length of the fixed crediting period of at most ten years (120 months) is determined for the proposed CDM project activity.

SECTION D. Environmental impacts

The legal framework for assessment of environmental impacts in Azerbaijan comprises several documents. The EIA Handbook issued on April 1996 was the first formal EIA provision in Azerbaijan outlining a 'classic' EIA procedure. However, the introduction of this document was not combined with the necessary publicity among the interested parties, such as potential project developers, various nongovernmental organisations (NGOs) and academic circles. Moreover, though considered as "mandatory guidelines" by the Ministry of Ecology and Natural Resources (MENR), this document clearly lacks the authority of a legislative act supported by appropriate political processes and commitments. The Handbook has not influenced the Government's official vision of the EIA system. The Law on Environmental Protection (Law on EP) of June 1999 reaffirms State Environmental Review (SER) as the central part of the national EIA system without reference to 'classic' EIA elements mentioned in the Handbook. As with other NIS, the Law transposes the generic Soviet SER model, which does not provide many essential internationally recognised elements of a 'classic' EIA process. Azerbaijan's ratification of the Espoo Convention in March 1999 and accession to the Århus convention in March 2000 may be seen as a reflection of the Government's commitment to enhance conformity of its environmental policy tools to international standards. However, joining these conventions did not affect the formal Azerbaijani EIA system as they appear to have no practical power and no precise implementation mechanisms in the country.

Formal EIA provisions in Azerbaijan contain neither a screening list nor explicitly define screening criteria. According to the Law on EP, the SER procedure should apply to virtually all projects and many non-project developments. According to the EIA Handbook, the decision on the need for EIA is taken on a case-by-case basis by the competent Environmental Authority, based on "a precedent" (that is, whether similar projects required EIA in the past) and a set of informal criteria developed based on the practice of the previous years. If a project of a particular type has not been undertaken before, it is subject to a preliminary EA in the form of an Application for an Environmental Permit. Based on this application, the Environmental Authority decides on the need to conduct a full-scale EIA. The same requirement applies to new technologies. The Law on EP requires the "documents related to the assessment of environmental impacts of the proposed activities" to be submitted for SER "in an appropriate form", but does not further clarify requirements for the EIA documentation. The EIA Handbook contains more detailed provisions on the content of EIA reports. It requires inclusion of: an introduction; project description; characteristics of the baseline environment; analysis of potential environmental impacts of the proposal; description of measures to avoid, mitigate, remedy or compensate for them; description of alternatives to the project; and a conclusion.

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

The proposed CDM project envisages capturing previously vented associated gas at Neft Dashlari and Palchig Pilpilesi oil fields and delivering it to the shore for end-users. For this purpose SOCAR will install 45 compressors and associated pipelines to connect them with gas collection pipeline at Neft Dashlari oil field. The installation and piping works will be carried out by Neftgasstroy – a subsidiary company of SOCAR. The project is designed to mitigate the negative environmental impact by capturing vented gas into atmosphere. By definition the project is to mitigate emissions of harmful gas methane. As such the project intends to have positive impact and negligible minor impacts on environment. The detailed EIA was conducted by "NeftGasLayihe" Institute of SOCAR within the technical feasibility study. The results of EIA testify that project has no negative impact on environment defined by both

national and international legislation. The copy of EIA will be made available for validation team. Furthermore, the project team employed an additional checklist to exercise EIA for the project. It was also revealed that project has no significant impact on environment. Checklist with relevant comments on impacts is submitted to DOE.

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

As negative environmental impacts are not considered significant, the comprehensive EIA is not required.

SECTION E. Stakeholders' comments

Signing the Århus Convention has become a significant step in the process of democratisation in Azerbaijan. This Convention lays out a number of specific requirements for public participation in the EIA process, primarily concentrated in its articles 6, 7 and 8. In line with the Århus Convention, the EIA Handbook guarantees free and timely access to the information on the proposed activities, requires the participants of the EIA process to notify the public concerned, to provide public access to the EIA documentation, to actively solicit and consider public opinion during the decision-making process, and to inform the public about the decision made.

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

SOCAR has conducted stakeholder consultations for its several projects in the past. It has enabled company to develop a pool of stakeholders and to have an established communication line with stakeholders. For the purpose of the proposed project the stakeholder list was reviewed, updated and several new NGOs added in.

The identified stakeholders were invited for the meeting and discussion on the proposed project. The project description and announcement about stakeholder consultations was published on the webpage of SOCAR's environmental department (http://www.socar.az/ed/162.php) and printed in the local newspaper. The stakeholder consultation meeting was held on November 26, 2009.

Deputy Director of ecology department of SOCAR Mr. Aflatun Hasanov opened meeting by greeting and welcoming audience. He presented slides about general activities of SOCAR in the field of environmental protection. Presentation provided overview on GHG inventories of company. Representative of EcoEnergy briefed participants about status of CDM project. Information about the methodology selected for the project and updates on the registered projects with this methodology was provided. Head of technical and science section Mr. Meherrem Mehdiyev presented the proposed project in detail in a manner, which allowed the local stakeholders to understand the project activity (the presentation is made available to the validator). His presentation covered scope of works, total value of investment and benefits of the project. Expert of Institute of Geology of National Academy of Science of Azerbaijan Republic Mr. Telet Kengerli in his speech gave an overview of the global climate change problem and supported the CDM initiative of the proposed project.

Audience gathered for the meeting generally supported project approach and expressed interest for obtaining further information. The minutes of stakeholder meeting and the documented list of participants are made available to DOE. The public meeting was broadcasted by local TV stations. Table E.1 below contains the list of the key stakeholders.

Table E.1. List of the attendees of the stakeholder meeting on November 26, 2009

#	NAME	ORGANIZATION	POSITION
1	Yaqub Ağasiyev	Ecology Department, SOCAR	Chief Engineer
2	Cabrayıl Cabrayılov	Ecology Department, SOCAR	Deputy Director
3	Maharram Mehtiyev	Ecology Department, Science and Technical Section, SOCAR	Head of Department
4	Anar Hüseynov	Ecology Department, SOCAR	External Relations officer
5	Füzuli Hacıyev	Ecology Department, Social Development section, SOCAR	Adviser
6	Shirvan Yusifov	Ecology Department, Ecological	Chief Specialist

		metering and waste management section, SOCAR	
7	Mammad Nasibov	Ecology Department (SOCAR)	Head of Monitoring section
8	Aliyev Sadıq	World Bank	Operations Analyst
9	Saadat Qafarova	“BP Azarbaycan”	Environmental Adviser
10	Talat Gangarli	National Academy of Science	Researcher
11	Çingiz Orucov	“Ekoenerji” MMC	Director
12	Matsuzava Kataro	Embassy of Japan in Azerbaijan	Secretary
13	Rıza Kağan Yılmaz	Embassy of Turkey in Azerbaijan	First Secretary
14	Ovçuyev Nizami	Ministry of Energy and Industry	Chief Specialist
15	Gülmalı Süleymanov	Minisrty of Ecology and Natural Resources	Head of Climate Change and Ozone Centre
16	Mirzaliyev Afsar	Executive Power of Azizbekov district	Lead Specialist
17	Seyidov Nadir	National Academy of Science	Lead Expert
18	Yaqubov Qaşam	State Land Committee	Expert
19	Telman Zeynalov	MEP Centre	Director
20	Fuad Axundzada	“Life and Nature” NGO	Director
21	İrada Yaqubova	ELS Independent Research Centre	Director
22	Sadıx Hasanov	“Towards Healty Life” NGO	Chairman of the board
23	Dr. Tofiq Samadov	ELS Independent Research Centre	Adviser
24	Firuza Sultanzada	Eko Sphere NGO	Director
25	Safarzada Anvar	Iglim NGO	Consultant
26	İslam Mustafayev	“Rusgar” NGO	Environmentalist
27	Farida Hüseynova	Greens movement NGO	Director
28	Aliyev Azizağa	“Azneft” Production Unit (SOCAR):	Deputy Head of Department
29	Nasibov Saday	Azneft” Production Unit (SOCAR):	Head of Department
30	Mahammad Qocayev	“Neft Daşları” NGDUi	Head of Department
31	Rahim Dashdıyev	“Neftqazelmitadqiqat” İnstitute	Head of Department
32	Safarov Qanimat	“Neftqazelmitadqiqat” İnstitute	Head of Department
33	Albuşov Shahabudin.	“Ekol MX” QSC	Head of Ecological Monitoring Department
34	Hüseyinli Oktay	N.A.	Public Representatives
35	Mammadov Mahammad	“Binaqadi oil Company”	Head of Department
36	Rzabayov İbrahim	Qarasu Operating Company	Head of Department
37	Sadıxova Camila	“Shirvan oyl” Operating Company	Environemntal manager
38	Yolçuyev Taryel	“Salyan oyl” Operating Company	Lead Manager
39	Badalov Anar	Abşeron Operating Company	Lead Engineer
40	Zaur Mammadov	“Azarenerji” ASC	Head of Ecological Department
41	Rauf Muradov	“Tamiz shahar” ASC	Chief of Ecological Department
42	Nail Rahimzada	Iki Sahil Newspaper	Reporter
43	Emil İsmayılov	Trend News Agency	Reporter
44	Teymur Mardanoğlu	Lider TV	Reporter
45	Latif Mustafayev	Nedelya Newspaper	Reporter
46	Eldaniz Sücaddinoğlu	Ictimai TV	Reporter
47	Xatira Cafarova	Azertaj News Agency	Reporter
48	İlham Mammadov	Azadinform News Agency	Reporter
49	Kamala Mustafayeva	Sherg News Agency	Reporter

Figure E.1.1.1. Announcement on the stakeholder meeting in the local newspaper.

ARDNŞ-in EKOLOGİYA İDARƏSİNİN TƏŞKİLATÇILIĞI İLƏ İCTİMAİ DİNLƏMƏLƏR KEÇİRİLƏCƏK

Noyabrın 26-da ARDNŞ-in Ekologiya İdarəsinin təşkilatçılığı ilə "Park İnn" mehmanxanasında BMT-nin KİOTO protokoluna uyğun olaraq "Neft Daşları" NQÇİ-nin neft yataqlarında alçaq təzyiqli səmt qazının utilizə edilməsi" layihəsi ilə bağlı ictimai dinləmələr keçiriləcəkdir. Tədbirdə layihənin məqsədi, iqlim dəyişmələri və ətraf mühit problemlərinin həllinə dair müzakirələr aparılacaqdır. Ekologiya İdarəsinin rəis müavini Əflatun Həsənov "ARDNŞ-in müəssisələrində istilik effekti yaradan qazların potensial mənbələri haqqında" təqdimat keçirəcək, QAZPROM Almaniya GmbH-nın nümayəndəsi inkişaf etmiş xarici ölkələrdə bu sahədə görülən və gələcəkdə görüləcək işlər barədə məlumatla çıxış edəcəkdir. ARDNŞ-in Ekologiya İdarəsinin elm və texnika şöbəsinin rəisi Məhərrəm Mehdiyev ictimai dinləmə iştirakçılarını "alçaq təzyiqli qazların utilizə edilməsi" layihəsinin məqsədləri barədə məlumatlandıracaq, AMEA-nın Geologiya İnstitutunun əməkdaşı Tələt Gəngərli isə Azərbaycan Respublikasında istilik effekti yaradan qazlar haqqında ümumi məlumat verəcək. Daha sonra dinləmələrdə iştirak edən QHT və şirkət nümayəndələrinin rəy və təkliflər dinləniləcək. Tədbirdə Ekologiya və Təbii Sərvətlər Nazirliyinin, AMEA-nın, ARDNŞ-in müvafiq qurumlarının təmsilçilərinin, respublikanın görkəmli ekoloqları və ictimaiyyət nümayəndələri iştirak edəcəklər. Maraqlananlar ARDNŞ-in Ekologiya İdarəsinin Xarici əlaqələr şöbəsinin rəisi Anar Hüseynovla (+99412) 521-08-35 və (+99450) 245-17-12 telefon nömrələri ilə əlaqə saxlaya bilərlər.

Any comments received from stakeholders after the meeting and the publications will be documented and responded according to internal procedures of SOCAR’s environmental department. The documented comments received from local stakeholders will be made available to the validation team. All responses to the stakeholder comments will be documented transparently. Due to SOCAR’s experience the project participants do not expect any negative feedback on the proposed project from the local stakeholders. As the project sites are situated far offshore, no comments are expected from broad public.

Figure E.1.1.2. Announcement of the stakeholder meeting by SOCAR

Source: www. socar.az/ed/162en.php accessed at the 26th December 2012.

E.2. Summary of the comments received:

The comments received by project participants during the stakeholder meeting covered different topics. The most comments and questions were raised by representatives of NGOs and scientific organizations.

In general the attendees were very positive about the proposed project and environmental protection activities by SOCAR. Table below provides a short summary of stakeholder comments. The minutes of the stakeholder meeting are available for DOE.

Table E.2.1: Summary of stakeholder comments

Stakeholder	Question/Comment Topic
Mrs. Farida Huseynova, Director "Green	Availability of infrastructure at Neft Dashlari for

Movement" NGO	pumping more gas from neighbouring platforms.
Representative of State Committee on Land, Mr. Yagubov Geshem	Other fugitive emissions emitted at SOCAR's facilities
Irade Yagubova, ELS local NGO	Delivery route of captured gas

The stakeholder concerns included involvement of individual stakeholders in the process of project development and preparation. Other requests addressed SOCAR's plans to reduce emissions at its refining facilities. Finally, the participants requested further information on:

- either the existing infrastructure and the proposed project might cover associated gas from neighbouring oil fields;
- either the project is to address further gases beside methane; and
- delivery route and use of recovered associated gas.

Taking into consideration the results of the stakeholder discussion there is no negative social impact due to the proposed project activity.

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

The project participants, in particular the representatives of SOCAR, clarified all questions raised during the stakeholder meeting and informed the participants on detailed data provided on the homepage of SOCAR's environmental department and on the upcoming special TV programme on SOCAR's environmental protection activities. Involvement of local experts in project preparation and development is highly appreciated by SOCAR. The SOCAR's specialists explained to the participants that reduction of the GHG emissions will be achieved by the proposed project due to recovery, transportation and use of the recovered gas onshore by end-consumers. Hence, the recovered gas will be transported to onshore processing facilities and further to end-consumers. The recovered gas representing a mixture of methane and further hydrocarbons is completely captured and transported onshore. Thus, the intention of SOCAR is to increase its associated gas utilization rate and reduce emissions of any harmful gases by OGPD Neft Dashlari.

Furthermore, the stakeholders received responds to their statements covering activities out of the boundary of the proposed project. Thus, the proposed activity and the existing infrastructure are sufficient only for associated gas recovered at OGPD Neft Dashlari, so that no neighbouring oilfields (BP) will be connected to the project infrastructure. SOCAR's representatives also explained that flaring of associated gas is still the better choice than venting for environment. Also a planned refurbishment of SOCAR's refining facilities was mentioned, which will also result in reduction of GHG emissions. This activity is still under preparation and the stakeholders will be invited for further consultations on this subject later.

None of the comments received by the project participants by the date of CDM PDD completion requires specific actions at this stage. The project participants are committed to continue consultations with relevant stakeholders throughout the project lifetime.

Annex 1
CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

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Annex 2

INFORMATION REGARDING PUBLIC FUNDING

The project is financed by the state-owned company, SOCAR. There is no public funding from the Parties of Annex I, involved in this project activity.

Annex 3

BASELINE INFORMATION

Data provided by the Gas Quality Certificate

Conditions	*Standard*	*Working*	*Normal*
Temperature and pressure	20°C & 101.325 kPa	25.1°C & 101.325 kPa	0°C & 101.325 kPa
Density, kg/m3		0.815	0.677
Net calorific value, kcal/m3	8,205	9,081	8,818
Net calorific value, MJ/m3	34.35	38.02	36.92
Wobbe index, kcal/m3	9,977	11,041	10,716

Re-calculation of results: Gas Quality Certificate

			Normal conditions						*Standard conditions*			
Gas component	**Chemical formula**	**Gas composition, volume %**	**NCV of gas component**		**NCV**		**Density of component**	**Gas Density**	**NCV of gas component**		**NCV**	
			kcal/Nm3	**MJ/Nm3**	**kcal/Nm3**	**MJ/Nm3**	**kg/Nm3**	**kg/Nm3**	**kcal/Sm3**	**MJ/Sm3**	**kcal/Sm3**	**MJ/Sm3**
methane	CH4	87.01	8,570	35.88	7,457	31.22	0.5548	0.483	7,980	33.41	6,943	29.07
ethane	C2H6	3.55	15,370	64.36	546	2.28	1.0480	0.037	14,300	59.85	508	2.12
propane	C3H8	1.43	22,260	93.18	318	1.33	1.5540	0.022	20,670	86.53	296	1.24
isobutane	iC4H10	0.87	29,320	122.78	255	1.07	2.0810	0.018	27,180	113.81	236	0.99
butane	nC4H10	0.00	29,510	123.57	0	0.00	2.0900	0.000	27,290	114.27	0	0.00
isopentane	iC5H12	0.47	37,410	156.63	176	0.74	2.6710	0.013	34,400	144.02	162	0.68
pentane	nC5H12	0.00	37,410	156.63	0	0.00	2.6710	0.000	34,400	144.02	0	0.00
hexan+higher hydrocarbon	C8+ (C6H14)	0.16	41,360	173.17	66	0.28	2.9760	0.005	38,540	161.36	62	0.26
nitrogen	N2	0.00	0	0.00	0	0.00	0.9670	0.000	0	0.00	0	0.00
carbon dioxide	CO2	6.51	0	0.00	0	0.00	1.5290	0.100	0	0.00	0	0.00
hydrogen suphide	H2S	0.0000	5,580	23.37	0	0.00	1.1880	0.000	5,200	21.75	0	0.00
oxygen	O2	0.0000	0	0.00	0	0.00	1.1050	0.000	0	0.00	0	0.00
Total		**100.00**			**8,818**	**36.92**		**0.677**			**8,206**	**34.36**

Table AN.3.1: Results of LP APG analysis

No	Oil field	Project site	Total low pressure APG volume, Sm3/year at 20°C	Total low pressure APG volume, Nm3/year at 0°C
1	N. Dashlari	2192	20.638.008	19.234.623
2	N. Dashlari	1517	30.212.119	28.157.695
3	N. Dashlari	741a	21.422.780	19.966.031
4	N. Dashlari	2346	34.115.958	31.796.073
5	Palchiq P.	1005a	13.793.024	12.855.098
6	Palchiq P.	1201	36.500.000	34.018.000
7	N. Dashlari	1799	18.997.050	17.705.251
8	N. Dashlari	810	39.873.477	37.162.081
	Total		**215.552.416**	**200.894.852**

No	Oil field	Project site	NCV, TJ/Nm3	Start of operations, month/year	Low pressure APG quantity, Nm3/year													
					2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	N. Dashlari	2192	0,00003692	3rd 2008	9.617.312	19.234.623	18.349.831	4.376.435	16.700.475	15.932.253	15.199.369	14.500.198	13.833.189	13.196.862	12.589.807	12.010.676	11.458.184	8.198.331
2	N. Dashlari	1517	0,00003692	3rd 2008	14.078.847	28.157.695	26.862.441	6.406.692	24.447.937	23.323.332	22.250.459	21.226.938	20.250.499	19.318.976	18.430.303	17.582.509	16.773.713	12.001.592
3	N. Dashlari	741a	0,00003692	1st 2009	0	19.966.031	19.047.594	4.542.851	17.335.520	16.538.086	15.777.334	15.051.576	14.359.204	13.698.681	13.068.541	12.467.388	11.893.888	8.510.077
4	N. Dashlari	2346	0,00003692	2st 2009	0	23.847.055	30.333.454	7.234.529	27.606.961	26.337.041	25.125.537	23.969.763	22.867.153	21.815.264	20.811.762	19.854.421	18.941.118	13.552.370
5	Palchiq P.	1005a	0,00003692	1st 2010	0	0	12.855.098	3.065.941	11.699.631	11.161.448	10.648.021	10.158.212	9.690.934	9.245.151	8.819.874	8.414.160	8.027.109	5.743.396
6	Palchiq P.	1201	0,00003692	4th 2011	0	0	0	8.504.500	32.453.172	30.960.326	29.536.151	28.177.488	26.881.324	25.644.783	24.465.123	23.339.727	22.266.100	15.931.394
7	N. Dashlari	1799	0,00003692	1st 2010	0	0	17.705.251	4.222.702	16.113.832	15.372.596	14.665.456	13.990.845	13.347.266	12.733.292	12.147.561	11.588.773	11.055.689	7.910.346
8	N. Dashlari	810	0,00003692	1st 2010	0	0	37.162.081	8.863.156	33.821.804	32.266.001	30.781.765	29.365.804	28.014.977	26.726.288	25.496.879	24.324.022	23.205.117	16.603.261
	TOTAL				**23.696.159**	**91.205.404**	**162.315.748**	**47.216.806**	**180.179.332**	**171.891.082**	**163.984.093**	**156.440.824**	**149.244.546**	**142.379.297**	**135.829.850**	**129.581.676**	**123.620.919**	**88.450.768**

Table AN.3.2: Low Pressure APG production including the production forecast over the lifetime of the project

Table AN 3.3 - OGPD Neft Dashlari Gas Balance for 2009 - 2020															
Year	**Oil Production, in 1000t**			**Gross Gas Extraction, in 1000m3**			**APG production, 1000m3**			**Quantity of gas required for gas-lift, 1000m3 per year**			**Gas Demand for GTPP, in 1000m3**	**Gas Purchased from 28th May, in 1000m3**	**Net Quantity Sent to GPPP, in 1000m3**
				B+A			**A**			**D**			**E**	**C**	**F**
	Oil field Neft Dashlari	Oil field Palchyg Pilpiljasi	Total	Oil field Neft Dashlari	Oil field Palchyg Pilpiljasi	Total	Oil field Neft Dashlari	Oil field Palchyg Pilpiljasi	Total	Oil field Neft Dashlari	Oil field Palchyg Pilpiljasi	Total	Total	Total	Total
2009	755,880	113,020	868,900	410,681	68,554	479,235	40,300	17,130	57,430	370,381	51,424	421,805	47,814	168,000	177,616
2010	738,360	138,200	876,560	399,606	79,581	479,187	37,810	16,700	54,510	361,796	62,881	424,677	51,307	144,775	147,978
2011	721,850	142,700	864,550	388,737	80,679	469,416	35,030	15,750	50,780	353,707	64,929	418,636	59,693	132,500	123,587
2012	708,790	138,500	847,290	379,837	76,848	456,685	32,530	13,830	46,360	347,307	63,018	410,325	60,000	133,000	119,360
2013	689,340	134,300	823,640	367,597	73,107	440,704	29,820	12,000	41,820	337,777	61,107	398,884	60,000	133,000	114,820
2014	683,250	129,800	813,050	361,753	69,299	431,052	26,960	10,240	37,200	334,793	59,059	393,852	60,000	133,000	110,200
2015	636,990	124,200	761,190	336,315	65,001	401,316	24,190	8,490	32,680	312,125	56,511	368,636	60,000	133,000	105,680
2016	606,030	121,600	727,630	318,365	62,368	380,733	21,410	7,040	28,450	296,955	55,328	352,283	60,000	133,000	101,450
2017	572,340	115,400	687,740	299,117	57,977	357,094	18,670	5,470	24,140	280,447	52,507	332,954	60,000	133,000	97,140
2018	520,990	110,200	631,190	270,915	54,201	325,116	15,630	4,060	19,690	255,285	50,141	305,426	60,000	133,000	92,690
2019	466,770	79,800	546,570	241,477	38,409	279,886	12,760	2,100	14,860	228,717	36,309	265,026	60,000	133,000	87,860
2020	423,580	56,900	480,480	218,584	26790	245,374	11,030	900	11,930	207,554	25,890	233,444	60,000	133,000	84,930

Annex 4

MONITORING INFORMATION

1. Introduction

The following Monitoring Plan is designed to inform the project operator about all necessary steps for data collection regarding the ex-post baseline, allowing the project to determine the net project emission reductions.

Net project emission reductions will be determined by the following principle step: monitoring of the ex-post baseline emissions and the ex-post project emissions. Monitoring of the ex-post baseline emissions comprise the calculation of the amount of GHG (in CO_2e) which would have been released in the absence of the proposed project. The ex-post project emissions will be determined based on CO_2 emissions due to electricity consumption and fossil fuel consumption for the purpose of the project activity.

There are several formulae for calculation of the emissions and emission reductions, which will be applied to each of the project sites. Table 1.1. below shows the data needed for the calculation of baseline emissions, project emissions and emission reductions. The table also contents a short description of the method for collection of the data and inputs required.

Table 1.1. Overview of Sources, Methods and Required Input

Source of Emissions /Emission Reductions	**Methods**	**Inputs required**
Baseline emissions: *CO_2 emissions due to fossil fuels combustion at end-users, that are produced from non-associated gas or other fossil sources.*	The volume of recovered associated gas and its net calorific value are used for determination of the volume of fossil fuels (natural gas) to be replaced by the end-users due to project implementation.	• Volumes of APG recovered at each of the project sites will be monitored continuously; • Monthly Net Calorific Value of the recovered APG for each of the project sites confirmed by the gas quality certificates prepared by the laboratory.
Project emissions: *CO_2 emissions due to electricity and fossil fuels use for pre-treatment and compression of the recovered gas*	The quantity of electricity consumed by the identified electricity consumption source is multiplied by the carbon emission factor for the captive power plant. The quantity of fossil fuel (associated gas) consumed by the project activity is multiplied by the carbon emission factor for the fuel.	• Number of onsite compressors operational during the monitoring period; • Input capacity of the onsite compressors in operation. • Carbon emission factor of the electricity generated by the captive power plant. • Gas consumption rate by the central compressor facilities and quantity of gas consumed during the monitoring period. • Carbon emission factor for combustion of associated gas.

Emission reductions	The net emission reductions are calculated by substraction of project emissions from baseline emissions	• Baseline emissions • Project emissions.

2. **Baseline methodologies**

The monitoring plan is based on the approved CDM methodology AM0009 version 05. This methodology provides for a very straightforward, conservative and simplified calculation of emission reductions. Through the conservative assumptions made in this methodology a number of monitoring parameters is reduced. The monitoring of the baseline is the same for all technological solutions chosen for the project sites. Formulae used for calculation of ex-post emission reductions are shown in Table 2.1. below.

Table 2.1. Formulae for calculation of emission reductions

PDD No.	Formulae	Determines parameter
(1)	$BE_y = V_{F,y} * NCV_{RG,F,y} * EF_{CO2,\ Methane}$	Baseline emissions during the period y
(2)	$PEy = PE_{FC,y} + PE_{EC,\ y}$	Project emissions in the period y
(3)	$PE_{FC,y} = FC_{i,y} * COEF_{i,y}$	CO2 emissions due to consumption of fossil fuels
(4)	$PE_{EC,y} = EC_{PJ,y} * EF_{EL,y} * (1+TDL_y)$	CO2 emissions due to consumption of electricity
(5)	$ER_y = BE_y - PE_y$	Emission reductions during the period y
(6)	$COEF_{i,y} = w_{C,i,y} * \rho_{i,y} * 44/12$	CO2 emission coefficient of fuel type i in year y
(7)	$FC_{i,y} = V_{F,y} * k$	Quantity of associated gas combusted in compression process during the year y
(8)	$EF_{EL,y} = (FC_{n,i,y} * NCV_{i,y} * EF_{CO2,i,y}) / EG_{n,y}$	Emission factor for electricity generation in year y
(9)	$EF_{CO2,i,y} = COEF_{i,y} / NCV_{i,y}$	CO2 emission factor of fossil fuel type i used in the period y

3. Monitoring parameters

Data collection and archiving

According to the project design document the list of parameters is presented in Table 4.1.1. below. These parameters shall be used for calculation of the baseline emissions, the project emissions and the emission reductions.

Table 4.1.1. List of values

No.	PDD ID No.	Parameter	Description	Value	Unit	Reference
P1	***1***	$EF_{CO2,Methane}$	CO2 emission factor for methane	**49,55**	tCO2/TJ	Default value AM0009 ver. 04
P2	***2***	T	Annual operating hours for plant/equipment x	**8760**	hours	Conservative assumption (full load operating hours)
P3	***3***	$TDL_{j,y}$	Average technical transmission and distribution losses for providing electricity to source j in year y	**0**		According to the tool
P4	***4***	k	Gas consumption rate for transportation of 1 cubic meter of gas by compressor 10GCNAM2/5-55	**0.075**	m3	Calculated based on data indicated in technical specification of the compressor
P5	***5***	P_J	Input capacity of NQK-7/1-5 compressor	**75**	kW	Indicated on the tag at the compressor onsite and in technical specification
P6	***6***	$V_{F,y}$	Volume of total recovered gas measured at point F in Figure 2, after pre-processing and before the part of the recovered gas may be used on-site, during the period y	**-**	Nm³	Measured by gas flow meters at the monitoring point F
P7	***7***	$NCV_{RG,F,y}$	Net calorific value of recovered gas measured at point F in Figure 2 during the period y	**-**	TJ/Nm3	Sampled and measured at the monitoring point F
P8	***8***	$FC_{i,j,y}$	Quantity of fuel type i combusted in process j during the year y	**-**	m3	Measured by project participants: ratio of the recovered gas
P9	***9***	$EC_{PJ,j,y}$	Quantity of electricity consumed by the project electricity consumption source J in year y	**-**	MWh/yr	Mesured by project participants
P10	***10***	$w_{C,i,j}$	Weighted average mass fraction of carbon in fuel type i in year y	**-**	tC/t	Calculated based on the results of gas chromatography

P11	***11***	$\rho_{i,y}$	Weighted average density of fuel type i in year y	-	t/Nm3	Calculated based on the results of gas chromatography
P12	***12***	$FC_{n,i,t}$	Quantity of fossil fuel type i fired in the captive power plant n in the time period y	-	Nm3	Measured by gas flow meters installed at the power plant
P13	***13***	$EG_{n,t}$	Quantity of electricity generated in captive power plant n in the time period y	-	MWh	Measured by electricity meters installed at the power plant
P14	***14***	$EF_{CO2,i,t}$	Average CO2 emission factor of fossil fuel type i used in the period y	-	tCO2/GJ	Calculated
P15	***15***	$NCV_{i,t}$	Average net calorific value of fossil fuel type i used in the period y	-	GJ/Nm3	Sampled and measured at the entry in power plant
P16	***16***	N	Number of electricity consumption sources operational during the period y	-		Monitored: number of compressors NQK-7/1-5 in operation
P17	-	ER_y	Emission reductions during the period y	-	tCO2e	Calculated
P18	-	BE_y	Baseline emissions during the period y	-	tCO2e	Calculated
P19	-	PE_y	Project emissions in the period y	-	tCO2e	Calculated
P20	-	$PE_{CO2,fossilfuels,y}$	CO2 emissions due to consumption of fossil fuels during the period y	-	tCO2e	Calculated
P21	-	$PE_{CO2,elec,y}$	CO2 emissions due to the use of electricity during the period y	-	tCO2e	Calculated
P22	-	d	Operational days per year	**365**	days	n/a
P23	-	n	Conversion factor for gas volume	**0.932**	Nm3/Sm3	Calculated (0/20 °C = 273.16/293.16 K)
P24	-	$EF_{EL,j,y}$	Emission factor for electricity generation for source j in year y	-	tCO2/MWh	Calculated
P25	-	$COEF_{i,y}$	CO2 emission coefficient of fuel type i in year y	-	tCO2/Nm3	Calculated

The following data have to be collected, evaluated and archived in order to monitor the ex-post baseline emissions within the project boundary and a responsible person has to be determined (Table 4.1.2.).

Table 4.1.2: Parameters to be monitored								
ID Nr.	**Data variable**	**Source of data**	**Data unit**	**Record m/c/d**[16]	**Recording frequency**	**Pro-portion of data monitored**	**How will the data be archived?**	**Responsible**
1	Volume of the total recovered gas measured during the period y	On-site flow meters	Nm^3	m	continuously	100%	Paper and electronically	Head of a project site is responsible for the daily record keeping and verification of gas recovery volume. Head of the project site reports monthly to the project manager in the head office. The project manager collects information from all project sites and prepares annual reports.
2	Net calorific value of the recovered gas	Chemical analysis by gas chromatog raphy	TJ/Nm^3	m/c	monthly	100%	Paper and electronically	Head of a project site is responsible for quarterly sampling of recovered gas by the accredited laboratory. The results of analysis, gas quality certificates, are delivered to the project manager in the head office. The project manager collects information from all project sites and prepares monthly and annual reports.
3	Quantity of fuel type i combusted in process j during the year y	Parameters 4, 6	Nm^3	m/c	monthly	100%	Paper and electronically	The project manager in the head office calculates the periodic fossil fuel consumption based on the quantity of recovered gas.
4	Quantity of electricity consumed by the project electricity consumption source J in year y	Parameters 2,5,16	MWh	c	monthly	100%	Paper and electronically	The project manager in the head office calculates the periodic electricity consumption based on a number of NQK-7/1-5 compressors in operation.
5	Weighted average mass	Chemical analysis by	tC/t	m/c	monthly	100%	Electronically	The Laboratory staff is responsible for the gas composition analysis. The results of the analysis are submitted to the project

[16] m = measured; c = calculated; d = determined

	fraction of carbon in fuel type i in year y	gas chromatography						manager in the head office. The project manager uses the electronic worksheet to calculate the parameter.
6	Weighted average density of fuel type i in year y	Chemical analysis by gas chromatography	t/Nm^3	m/c	monthly	100%	Electronically	The Laboratory staff is responsible for the gas composition analysis and determination of the gas density. The results of the analysis are submitted to the project manager in the head office.
7	CO2 emission coefficient of fuel type i in year y	Parameters 5 and 6	tCO_2/Nm^3	c	monthly	100%	Paper and electronically	The project manager uses the electronic worksheet to calculate the parameter.
8	Quantity of fossil fuel type i fired in the captive power plant n in the time period y	Flow meters	Nm^3	m	monthly	100%	Paper and electronically	Operators of the gas-turbine plan keep records on the metering devices. Head of the gas-turbine power plant reports to the project manager in the head office.
9	Quantity of electricity generated in captive power plant n in the time period y	Electricity meters	MWh	m	monthly	100%	Paper and electronically	Operators of the gas-turbine plan keep records on the metering devices. Head of the gas-turbine power plant reports to the project manager in the head office.
10	Average net calorific value of fossil fuel type i used in the period y	Chemical analysis by gas chromatography	GJ/Nm^3	m/c	quarterly	100%	Paper and electronically	The Laboratory staff is responsible for the gas composition analysis and determination of the calorific value of gas. The results of the analysis are submitted to the project manager in the head office.
11	Number of electricity consumption sources operational during the period y	Technical logs and reports from the project sites	-	d	monthly	100%	Paper and electronically	Operators of at the offshore collector platforms keep records on the compressors NQK-7/1-5 in operation. Head of the project site reports to the project manager in the head office.

4. Calculation of the ex-post emission reductions

Formulae used for calculation (Table 2.1)	
Project emissions	2-4 & 6-9
Leakage	N/A under the methodology AM0009 version 05
Baseline emissions	1
Emission reductions	5

5. Environmental and social impact assessment

As no significant negative environmental and social impacts resulting from the proposed project activity were identified during the PDD preparation, monitoring of these impacts is not required.

6. Quality control and quality assurance procedures

Quality is assured and controlled by appointing a competent manager, who will be responsible for internal monitoring processes and for transparency of reports and records. Metering of associated gas volumes should be carried out automatically by calibrated flow meters and operated according to the requirements stated in the technical specification. Periodic state inspection of meters by appropriate institutions further insures a correct handling of monitoring units. To ensure a quality of measurements undertaken the accredited gas quality laboratory of SOCAR will be involved in the monitoring process. Internal instructions for operators of the power plant, offshore collector platforms, and the laboratory shall be developed. Periodic trainings will be conducted for the personnel involved in the project monitoring.

7. Operational and management structure for monitoring

Allocation of the project management responsibility

The management and operation of the CDM project is carried out by SOCAR (the project operator). It is the key responsibility of the project operator to ensure credibility of the project through accurate and systematic monitoring of project operations and reporting on emission reductions achieved.

The operator shall appoint a technical manager, who will be responsible for data collection, preparation of monitoring reports and calculation of emission reductions. The responsible technical manager will have the overall responsibility for preparation of the monitoring report, coordinating data collection from each of the project sites. The project operator will sign off on all official reports, GHG emission reduction protocols and worksheets. This will confirm that the official documentation is kept on record.

The project operator is responsible for development and implementation of the internal procedures for monitoring of emission reductions achieved by the project activity. All departments relevant for the monitoring process will receive clear instructions for completion of the monitoring requirements. The initial project validation will assess either the proposed monitoring procedures are satisfactory for verification of emission reductions. Table B.7.2.1. presents the initial distribution of responsibilities.

Table 7.2.1.: Distribution of responsibilities within the monitoring process

Responsible Staff	Area of responsibility
Operational staff at the project sites	• Archiving and reporting the data metered by gas flow meters; • Archiving and reporting the data on NQK-7/1-5 compressors in operation; • Records on special events (special event log); • Attending sampling of the recovered gas by the laboratory staff.
Operational staff at the gas-turbine power plant	• Archiving and reporting the data metered by gas flow meters at entry into power plant; • Archiving and reporting the metered data on electricity generation; • Attending sampling of the delivered gas conducted by the laboratory staff.
Technical Specialist of OGPD Neft Dashlari	• Collection and archiving of the data submitted by operational staff at the project sites and at the gas-turbine power plant; • Supervision of periodic calibration of all meters involved in the project, • Supervision of internal and external technical inspections of the compressors involved in the project activity (according to the national industry standards); • Preparation of monthly monitoring reports and their submission to the technical manager of the Ecology Department.
Technical manager, Ecology Department of SOCAR	• Collection and archiving of the data submitted by the laboratory and the technical specialist of OGPD Neft Dashlari • Regular training of the operational staff involved in the monitoring process; • Preparation and if required adaptation of the internal monitoring procedures and instructions; • Preparation of the internal monthly monitoring reports; • Preparation of the annual monitoring reports for the project verification.
Gas analysis specialists, Laboratory of SOCAR	• Periodic sampling of the recovered gas at the project sites and the fuel gas delivered to the gas turbine power plant; • Analysis of gas composition including determination of the net calorific value and the gas density; • Archiving and reporting the determined values to the Technical Manager of the SOCAR's Ecology Department of SOCAR; • Submitting the copies of valid accreditation certificates to the Technical Manager of the SOCAR's Ecology Department.

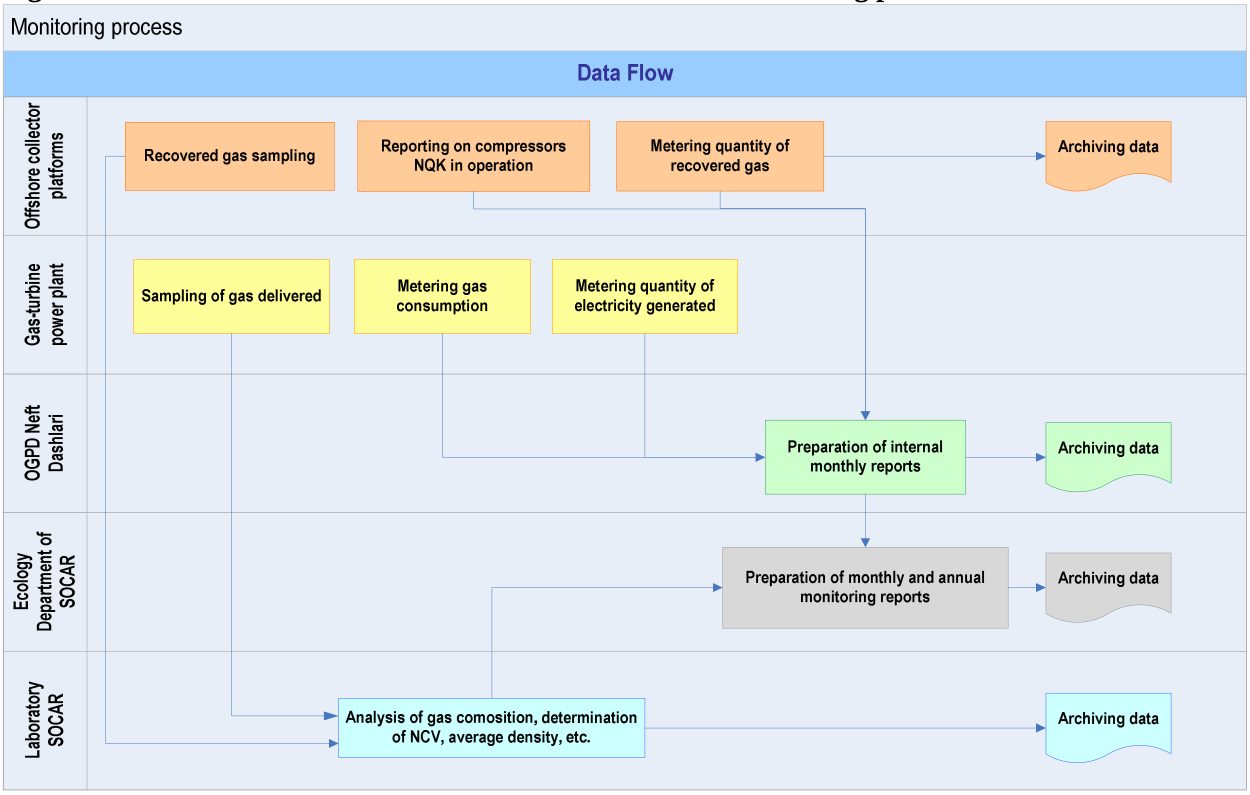
Data handling

Data to be collected for the purpose of the project monitoring includes parameters described in B.7.1. The responsible technical manager will assure that the data is collected as required. The collected data will be kept both in a paper and electronic form. For electronic data copies regular backups will be conducted. Frequency of the data collection is stated in B.7.1. A monthly internal report will be prepared based on the excel worksheet by the responsible technical manager. These monthly reports will be used for quality assurance when compared with the annual data reported by each of the project sites.
The data collected for the purpose of the project monitoring shall be kept at least for 2 years after the end of the crediting period.

Reporting

Besides internal monthly reports the project operator will prepare periodic reports as needed for audits and verification purposes. The annual reports will include information on the overall project performance, baseline emissions, and emission reductions achieved, compliance of achievements with environmental and social targets, methods of calculation, relevant references to the data sources, description of internal monitoring procedures. Figure B.7.2.1. shows the data flows within the project monitoring process. Precise instructions and requirements for data submission will be developed by the responsible technical manager.

Figure B.7.2.1. Schematic illustration of data flows within monitoring process



8. Calculation worksheet

The collected data will be fed into the calculation worksheet. This worksheet contains all relevant parameters and calculates baseline emissions and emission reductions automatically. Table 8.1. below shows the worksheet. The full excel model is submitted to DOE.

Monthly monitoring report by the project site: | **Month:** | **Year:**

!! Fill in only the cells marked blue !!

1. Calculated values

Variable in PDD	Indication	Unit	Value	Responsible
Volume of total recovered gas measured at point F during the month	$V_{F,y}$	Nm^3	0	
Net calorific value of recovered gas measured at point F, during the month	NCV	TJ/Nm^3	0.00000000	
Quantity of electricity consumed by the project in month	$EC_{PJ,y}$	MWh	0.00000000	
Quantity of fossil fuel combusted in process during the month	$FC_{i,j,y}$	Nm3	0.00	

Equatation	Indication	Unit	Value	Responsible
Ex post baseline emissions during the month	$BE_{y,post}$	tCO2	0	
Project emissions during the month	PE_y	tCO2	#DIV/0!	
Total emission reductions during the month	ER_y	**tCO2**	#DIV/0!	

2. Monitored parameters

2.1. Recovered gas quantity

Volume of gas recovered in month	Day no.	Unit	Value	Responsible
Total volume of gas recovered in month		Nm^3	0	

2.2. Composition of recovered gas and net calorific value - *Source of data: Monthly Gas Quality Certificate!*

Gas quality certificate dated:	

Gas component	Molecular weight	Chemical formula	Volume ratio, %	NCV of gas component, kCal/Nm3	Carbon content of component, tC/t	Density of gas component, kg/Nm3	Volume of component, 1000Nm3	Mass of component, t	Responsible

Variable: net calorific value	Unit	Value	Responsible
Net calorific value of recovered gas	$kCal/Nm^3$		
Net calorific value of recovered gas	TJ/Nm^3	0	
Weighted average density of recovered gas	kg/Nm^3	#DIV/0!	
Weighted average mass fraction of carbon in recovered gas	tC/t	#DIV/0!	

2.3. Number of compressors in operation and the electricity consumption - *On-site operator indicates a number of compressors in operation*

Number of NQK in operation	Day no.	Value, number	Input capacity, kW	Operational hours per day	Electricity consumed,	Responsible
Quantity of electricity consumed in month, MWh					0	

Table 8.1. Calculation worksheet (Complete electronic table submitted to DOE)

Annex 5: List of abbreviations

APG	Associated Petroleum Gas
BPS	Booster pumping station, Rus. DNS
CAPEX	Capital Expenditures
CDM	Clean Development Mechanism
CH_4	Methane
CO_2	Carbon dioxide
CO_{2e}	CO2 equivalent
CPF	Central Processing Facility
EIA	Environmental Impact Assessment
EUR	Euro
GHG	Greenhouse Gases
GPP	Gas Processing Plant
GTPP	Gas-Turbine Power Plant
GWh	Gigawatt hours
GWP	Global Warming Potential
IRR	Internal Rate of Return
kW	kilowatt
LNG	Liquefied natural gas
mm	millimetres
MENR	Ministry of Ecology and Natural Resources
MPa	Mega Pascal
MWel	Megawatt electric
MWh	Megawatt hours
MWth	Megawatt thermal
N_2O	Nitrous oxide
Nm^3	Normal cubic meters
NPV	Net Present Value
OGPD	Oil and Gas Production Department
OPU	Oil Processing Unit
PDD	Project Design Document
QA	Quality Assurance
QC	Quality Control
SOCAR	State Oil Company of Azerbaijan Republic
t	tonne
TJ	Terra joule
UNEP	United Nations Environmental Programme
UNFCCC	United Nations Framework Convention on Climate Change

Annex 6: Investment Analysis of the Project Alternatives

Table AN.6.1: Cash flow analysis of the project alternatives

Alternative 1: CashFlow

	Variables, EUR	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	Total, EUR
		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	
1	Capital expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Operational expenses		29,233	112,518	200,245	201,526	224,213	213,900	204,060	194,673	185,718	177,175	169,025	161,250	153,188	145,528	138,252	2,510,506
3	Operational revenues		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Income from operational activities (3-2)		-29,233	-112,518	-200,245	-201,526	-224,213	-213,900	-204,060	-194,673	-185,718	-177,175	-169,025	-161,250	-153,188	-145,528	-138,252	-2,510,506
5	Net income from operational activities		-29,233	-112,518	-200,245	-201,526	-224,213	-213,900	-204,060	-194,673	-185,718	-177,175	-169,025	-161,250	-153,188	-145,528	-138,252	-2,510,506
6	Cash-Flow undiscounted (5-1)	0	-29,233	-112,518	-200,245	-201,526	-224,213	-213,900	-204,060	-194,673	-185,718	-177,175	-169,025	-161,250	-153,188	-145,528	-138,252	-2,510,506
7	Cash-Flow discounted	0	-26,101	-89,699	-142,530	-128,073	-127,225	-108,368	-92,306	-78,625	-66,972	-57,046	-48,591	-41,389	-35,107	-29,778	-25,258	-1,097,068
	NPV without carbon revenues	-1,097,068																
	IRR without carbon revenues	-																

Alternative 2: CashFlow without carbon

	Variables, EUR	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	Total, EUR
		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	
1	Capital expenses	4,971,629	8,286,049	3,314,419	0	0	0	3,796,064	0	0	0	0	3,796,064	0	0	0	0	24,164,225
2	Operational expenses		622,330	2,321,177	4,110,644	4,136,765	4,599,554	4,389,171	4,188,467	3,996,994	3,814,330	3,640,068	3,473,822	3,315,223	3,150,763	2,994,526	2,846,101	51,599,934
3	Operational revenues		1,227,222	4,377,694	7,790,861	7,840,682	8,723,390	8,322,114	7,939,296	7,574,089	7,225,681	6,893,299	6,576,208	6,273,702	5,960,017	5,662,016	5,378,915	97,765,186
4	Gross Income "Operational Activity" (3-2)		604,892	2,056,517	3,680,217	3,703,917	4,123,836	3,932,942	3,750,830	3,577,095	3,411,351	3,253,232	3,102,386	2,958,479	2,809,254	2,667,490	2,532,814	46,165,252
	Depreciation				1,138,819	1,138,819	1,138,819	1,138,819	125,552	125,552	125,552	125,552		125,552	125,552	125,552	125,552	5,559,696
	Fair value (end of project)																0	0
5	Net Income "Operational Activity" (-tax)		471,816	1,604,083	3,121,109	3,139,596	3,467,132	3,318,235	2,953,269	2,817,755	2,688,475	2,565,142	2,419,861	2,335,235	2,218,840	2,108,264	2,003,217	37,232,030
6	Cash-Flow undiscounted (5-1)	-4,971,629	-7,814,233	-1,710,336	3,121,109	3,139,596	3,467,132	-477,829	2,953,269	2,817,755	2,688,475	2,565,142	-1,376,203	2,335,235	2,218,840	2,108,264	2,003,217	13,067,804
7	Cash-Flow discounted	-4,971,629	-6,976,994	-1,363,470	2,221,544	1,995,270	1,967,344	-242,083	1,335,909	1,138,044	969,491	825,907	-395,625	599,397	508,501	431,393	365,980	-1,591,022
	NPV without carbon revenues	-1,591,022																
	IRR without carbon revenues	9.71%																
																		52,202,199

Alternative 2: CashFlow with carbon

	Variables, EUR	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	Total, EUR
	Carbon related costs	0	12,500	37,500	43,958	69,974	67,960	66,039	64,206	62,458	60,790	59,199	57,681	0	0	0	0	602,265
	Carbon revenues		0	0	2,089,057	1,986,469	1,888,600	1,795,233	1,706,161	1,621,186	1,540,121	1,462,784	0	0	0	0	0	14,089,612
8	Carbon cashflow undiscounted	0	-12,500	-37,500	2,045,100	1,916,496	1,820,640	1,729,194	1,641,955	1,558,728	1,479,330	1,403,585	-57,681	0	0	0	0	13,487,348
9	Total cash-flow undiscounted (8+6)	-4,971,629	-7,826,733	-1,747,836	5,166,209	5,056,092	5,287,773	1,251,366	4,595,224	4,376,484	4,167,806	3,968,727	-1,433,884	2,335,235	2,218,840	2,108,264	2,003,217	26,555,152
10	Total cash-flow discounted	-4,971,629	-6,988,154	-1,393,364	3,677,205	3,213,238	3,000,424	633,981	2,078,646	1,767,588	1,502,953	1,277,824	-412,207	599,397	508,501	431,393	365,980	5,291,774
	NPV with carbon revenues	5,291,774																
	IRR with carbon revenues	19.21%																