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

CONTENTS

SECTION A. General description of project activity

A.1. Title of the Project Activity:

Recovery and Utilization of Associated Gas to Optimize Power Generation at PETROAMAZONAS Block 15 Facilities
Version 05, Date: 16 October 2012

Version history:

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Version 04	Submitted for registration	19.6.2012
Version 05	Re-submitted for registration after completeness check	16.10.2012

A.2. Description of the Project Activity:

A 2.1 The purpose of the Project Activity and Technical Challenges

Availability of power is essential to the oil industry since production activities involve handling fluids (oil and water) in e.g. down hole pumps, secondary crude / water piping facilities, processing facilities, water injection facilities, primary oil pumping facilities, etc. All of these facilities are driven by mechanical or electrical power. For oil production operations reliability of power supply is essential since a power cut not only generates significant losses through lost production but also the potential of generating collateral damages due to down hole pumps not starting up again after a shutdown.

The purpose of the Project Activity is to utilize associated gas that was previously flared or would have been flared in the absence of the Project Activity at the Block 15[1] and Block 31 in Ecuador. Rather than continue with the current practice of flaring the associated gas PETROAMAZONAS EP´s uses the associated gas for on-site power generation to supply part of the power demand of the oil field operations and thereby reduce GHG emissions. The main reasons associated gas is flared is because: i) funds within oil companies are normally prioritized for drilling and crude processing facilities (company market value and returns are determined by oil reserves and production: not by energy efficiency efforts); ii) the unstable and uncertain nature of associated gas presents significant technical and economical challenges and risks (see Charts No. 1 and 2) for power generation (risk of ending up with stranded assets); and, iii) lack of infrastructure for gas handling / transportation.

The associated gas that is wasted in flares of Block 15 and Block 31 represents an important energy source. For this Project Activity it is critical to identify and mitigate all the variables that impact the

[1] Block 15 was split up into Block 12 and Block 15 as per Resolution No. 0755 dated the 9th of August 2011 issued by the Hydrocarbon Secretary of the Ministry of Petroleum and Mines (Resolucion No. 0755 del 09 de agosto del 2011 de la Secretaria de Hidrocarburos).

stability and reliability of power supply using as a fuel associated gas whereby these variables range from: actual crude oil production versus forecast, water cut, Gas Oil Ratio (GOR), gas quality / composition, stability and quantity. These variables are never 100% predictable or stable which poses significant challenges to using associated gas for power generation in an industry where 100% reliability of power supply is of vital importance. Changing the operational environment and practices of an existing oil operations to endorse utilization of associated gas is highly challenging due to unconventional capital expenditure requirements, potential loss of crude oil production during project implementation, potential risk of ending up with a "stranded asset" due to possible sharp decline in oil production and significant technical and operational barriers that need to be overcome to guarantee reliable power using as a fuel unstable and unreliable associated gas. Converting an unstable raw material (associated gas) into a stable product (electricity) is a challenging endeavor.

The proposed Project Activity is the first project in the oil industry in Ecuador to modify existing oil field facilities / infrastructure ("Brownfield") to enable the utilization of associated gas for power generation, even though the existing crude oil and diesel power generation infrastructure in the oil field already meets existing and future power demands. Normally, associated gas utilization for power generation is either implemented as a "Greenfield" project, part of initial scoping and design phase of the oil field projects or not at all.

Upon the start of the Project Activity there was no requirement on the part of PETROAMAZONAS EP to invest in additional power capacity to meet existing and future power demand since the previous operator had already installed sufficient diesel and crude oil power generation equipment. It should be noted that, based on the overall oil production forecast, the overall electricity demand is expected to drop significantly over time. In this respect PETROAMAZONAS EP only has two alternatives for associated gas, namely: i) continue with the "business as usual; "flaring the associated gas" (see Picture No. 1) or, ii) optimizing the associated gas for power generation as an energy efficiency initiative.

The Project Activity has the following specific characteristics:

- It is implemented by one of the project participants (PETROAMAZONAS EP).
- It constructs and upgrades new resp. existing facilities and processes.
- It uses a waste resource on the project site that is NOT tradable.
- PETROAMAZONAS EP does not pay for crude oil it uses for power generation.
- On the basis of the existing terms and conditions of its operating license, PETROAMAZONAS EP does not receive a monetary consideration (income) for the crude oil produced from its oil fields but instead this is the quid pro quo of its production costs, and thus has no access to market price.

A 2.2 How the proposed Project Activity reduces greenhouse gas emissions

Under the Project Activity GHG emission reductions will be achieved by gathering and processing the associated gas coming from Block 15 and Block 31 and subsequently treating and transporting the gas to power generating facilities suitable for associated gas. Apart from this it is necessary to put in place power distribution facilities to transport the power to the various end users since, under current circumstances; power is generated at each oil well location.

The existing situation of flaring would be continued in the absence of possible income from CDM; the associated gas was flared or would have been flared, and liquid fossil fuel – which is a higher carbon

intensive fuel – would have been used to generate power. As part of the Project Activity the associated gas (i) will be used as fuel for power generation and (ii) will displace liquid fossil fuels that are used in the existing power generation equipment whereby this will lead to a reduction in greenhouse gases emissions.

A 2.3 Contribution to Sustainable Development

The Project Activity contributes to the sustainable development of Ecuador for the following reasons:

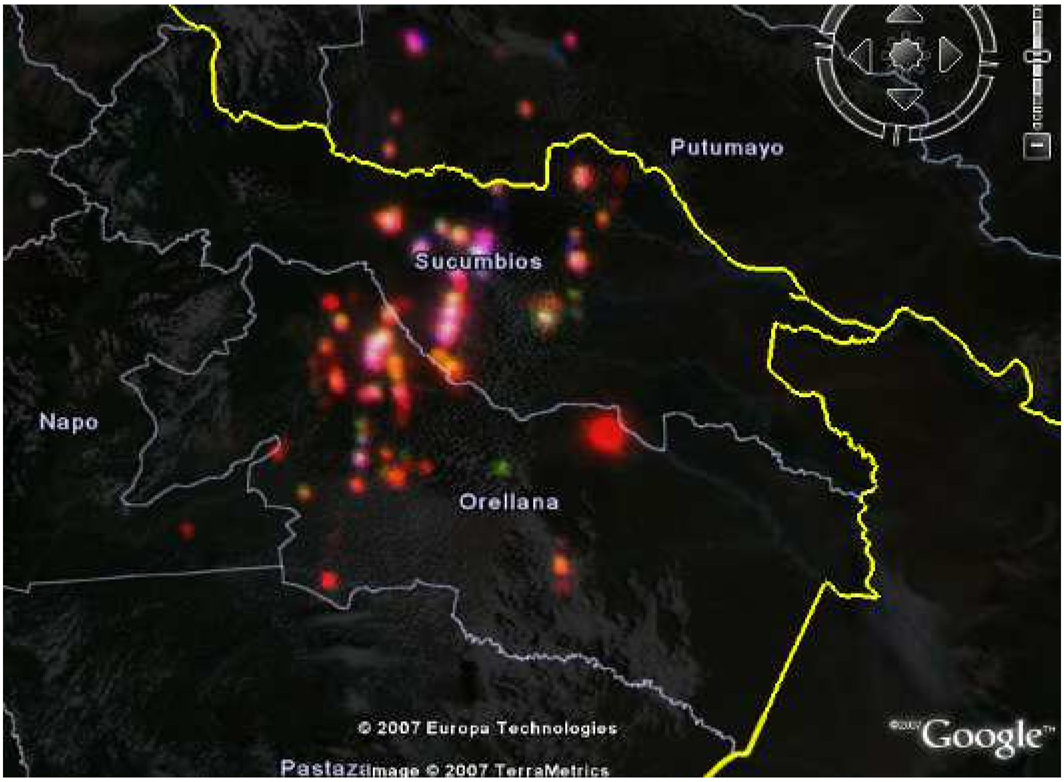
- Fuel switch from liquid fuel (either diesel or crude oil) to associated gas will significantly reduce SOx and NOx emissions, mitigating air pollution and its adverse impacts on human health.
- Gas-flaring reduction avoids the release of pollutants due to improper combustion of gas in the flare, which is evident from the smoke that is released. This subsequently contributes to increased hazardous chemicals, such as volatile organic compounds, released into the environment. Furthermore, and relevant to the Amazonian Region, the recovery and utilization of flare gas diminishes exposure of the endemic insects to the flaming heat, which attracts them specifically at night.
- All but an insignificant amount of power produced in PETROAMAZONAS EPs´ facilities before the project implementation was generated with either diesel or crude oil. By substituting the electricity generated with liquid fossil fuel with electricity generated with associated gas, the proposed Project Activity will save approximately 25 million gallons of fossil fuel per year, which thus leads a reduction of emissions as well as to the conservation of depleting non-renewable (fossil) natural resources[2].
- Part of the power generation capacity will continue to be based on liquid fossil fuels even with the Project Activity due to: i) certain remote locations will not be interconnected to the new gas-based electricity infrastructure given lack of critical mass / economy of scale ii) there is not enough associated gas available to generate 100% of the power demand. The portion of power generated with liquid fossil fuels in a year varies according to the power demand and the availability (quantity and quality) of associated gas: and, iii) given the decrease in oil production over time the availability of associated gas will also drop making it necessary to rely on fossil liquid fuels because gas volume reduces or increases linearly with the oil production.
- The Ministry of Electricity and Renewable Energy estimates that almost 80% (see document “Strategic policies to change the energy matrix” 3) of the associated gas in Ecuador is wasted (see Picture No. 1). Gas flaring is common because: i) of a lack of incentives for associated gas utilization on a national level, ii) optimizing associated gas utilization does not contribute materially to company revenues and profit, iii) high investment cost related to gas utilization and iv) high level of uncertainty in terms of future quantity and quality of associated gas. The National Energy Policies (2008 – 2020) encourage (although no incentives are provided, nor has it made it mandatory) the sustainable use of non renewable energy resources. One focus area is that of optimizing flare gas to reduce the dependency of diesel for power generation[3].
- The Ecuadorian Government sees the Project as a valuable example to promote energy efficiency and use of local energy sources in order to increase energy independency, in conjunction with which it also sees the CER income as a valuable source of co-financing for potential projects. The Project

[2] Please refer to the Investment Analysis calculation.

[3] Ministry of Electricity and Renewable Energy, “Strategic policies to change the energy matrix”, May 2008.

Activity's ground breaking initiative by using future CERs to leverage project funding has been acknowledged by the President of Ecuador and most senior members of the Cabinet.

- Finally, by utilizing associated gas for power generation, the Project Activity will contribute to promoting advanced environment-friendly technology in the oil industry in Ecuador and regionally in Latin-America, and serve as an example and role model for other oil companies in terms of energy efficiency and environmental responsibility.



Picture No. 1: Associated gas flared in Petroleum sector in Ecuador (Source: GGFR).

A.3. Project Participants:

Name of party involved	**Private and/or public entity(ies)**	**Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)**
Republic of Ecuador (Host)	PETROAMAZONAS EP	No
Republic of Finland	Wärtsilä Finland Oy	No
Sweden	Tricorona Carbon Asset Management Pte Ltd.	No

A.4. Technical Description of the Project Activity:

A.4.1. Location of the Project Activity:

The Project Activity is located within the oil fields known as Block 15 and Block 31 operated by PETROAMAZONAS EP, which is in the Amazonian Region.

A.4.1.1. Host Party(ies):

Republic of Ecuador

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

Sucumbios and Orellana Provinces

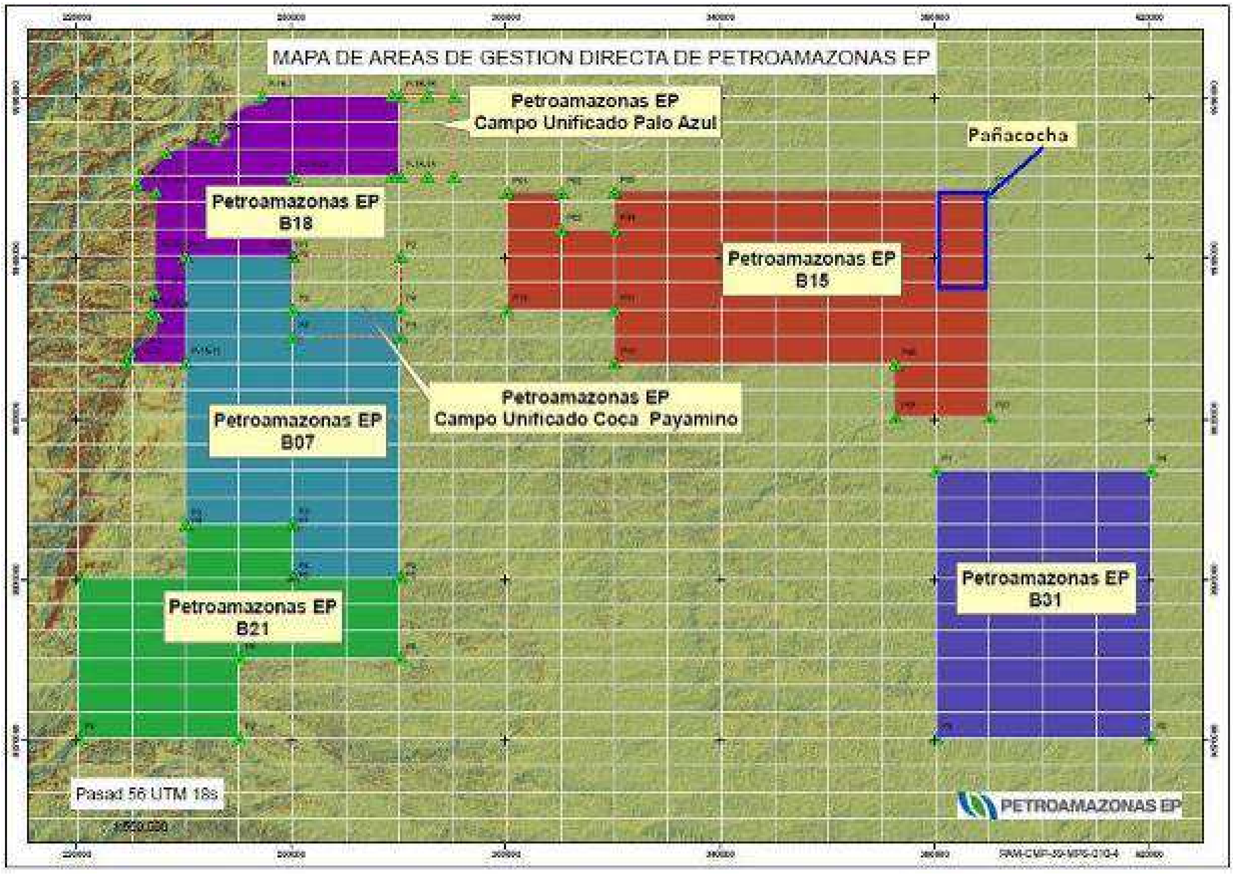
A.4.1.3. City/Town/Community etc.:

Province	Town
Sucumbios	Shushufindi
	Lago Agrio
	Cuyabeno
Orellana	Orellana
	La Joya de los Sachas

Source: ENTRIX, "Internal environmental audit to current power generation systems at Indillana, Limoncocha and Yanaquincha and Eden Yuturi Field"

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

The Project oil reservoirs, fields and oil wells where the associated gas is collected (flared in absence of the Project Activity), as well as the gas recovery, consisting of gas transportation, treatment and processing infrastructure, are located in the Block 15 and Block 31. Please refer to the "Map of Areas of Direct Control of PETROAMAZONAS EP".



Map No. 1: Geographic Project Boundary

Please find below the table with GPS coordinates for the Block 15 and the Block 31:

#	Latitude	Longitude
Block 15		
P01	0° 15' 4.390" S	76° 47' 41.843" W
P02	0° 15' 4.433" S	76° 42' 18.481" W
P03	0° 18' 45.221" S	76° 42' 18.765" W
P04	0° 18' 45.273" S	76° 36' 55.386" W
P05	0° 14' 57.374" S	76° 36' 55.355" W
P06	0° 14' 57.599" S	75° 59' 11.362" W
P07	0° 37' 45.330" S	75° 59' 11.341" W
P08	0° 37' 45.209" S	76° 8' 39.808" W
P09	0° 32' 19.889" S	76° 8' 39.743" W
P10	0° 32' 19.193" S	76° 36' 55.356" W
P11	0° 26' 53.627" S	76° 36' 55.278" W
P12	0° 26' 53.472" S	76° 47' 42.029" W
Block 31		
P1	0° 43' 10.790" S	76° 4' 34.890" W

P2	1° 10' 19.529" S	75° 43' 1.243" W
P3	1° 10' 19.112" S	76° 4' 35.391" W
P4	0° 43' 11.163" S	75° 43' 0.909" W

The gas processing facilities (gas treatment, power generation, etc.) are in the following locations, which are located in the Block 15 operated by PETROAMAZONAS EP:

Location Name	**GPS coordinates**	
	Latitude	**Longitude**
Central Production Facilities (CPF), including:	0° 22' 30" S	76° 37' 59" W
LIMONCOCHA Production Facilities	0° 20' 45" S	76° 40' 24" W
PAKA SUR	0° 25' 37" S	76° 47' 35" W
EDEN YUTURI Production Facilities	0° 31' 49" S	76° 07' 42" W
YAMANUNKA	0° 20’ 05’’ S	76° 41’ 50’’ W

A.4.2. Category(ies) of Project Activity:

Sectoral scope 10: Fugitive emissions from fuels (solid, oil and gas).

A.4.3. Technology to be employed by the Project Activity:

A. TECHNICAL CHALLENGES FOR ASSOCIATED GAS UTILIZATION PROJECTS:

As indicated in Section A 2 above, utilization of associated gas is often overlooked by oil companies due to the fact that unstable and uncertain nature of associated gas (see Chart No. 1 and 2 below) imposes significant technical and economical challenges and risks for power generation. The uncertainty over future associated gas supply and power demand based on company production forecasts also creates a risk of ending up with stranded assets. The cost and complexity of infrastructure to handle and transport associate gas and power distributions systems is another barrier to associated gas development.

It is important to note that power generation fuelled by associated gas differs materially from natural gas fuelled power generation because:

- Associated gas supply volumes are extremely unstable as is indicated in Chart No. 1 because certain wells come on and off line and the fact that fluids and associated gas are separated in secondary pipelines prior to reaching the central production facility where associated gas is taken for power generation (water, crude and associated gas are therefore supplied in batches).

- Associated gas composition is extremely unstable as indicated in Chart No. 2 whereby this has to do with the fact that fluids with the corresponding associated gas come in batches whereby these are not homogenous.
- Long term associated gas projections are very uncertain and are constantly updated. Freezing design criteria and parameters is essential but at the same time involves considerable risks given the fact that the Project Activity could end up with stranded assets.

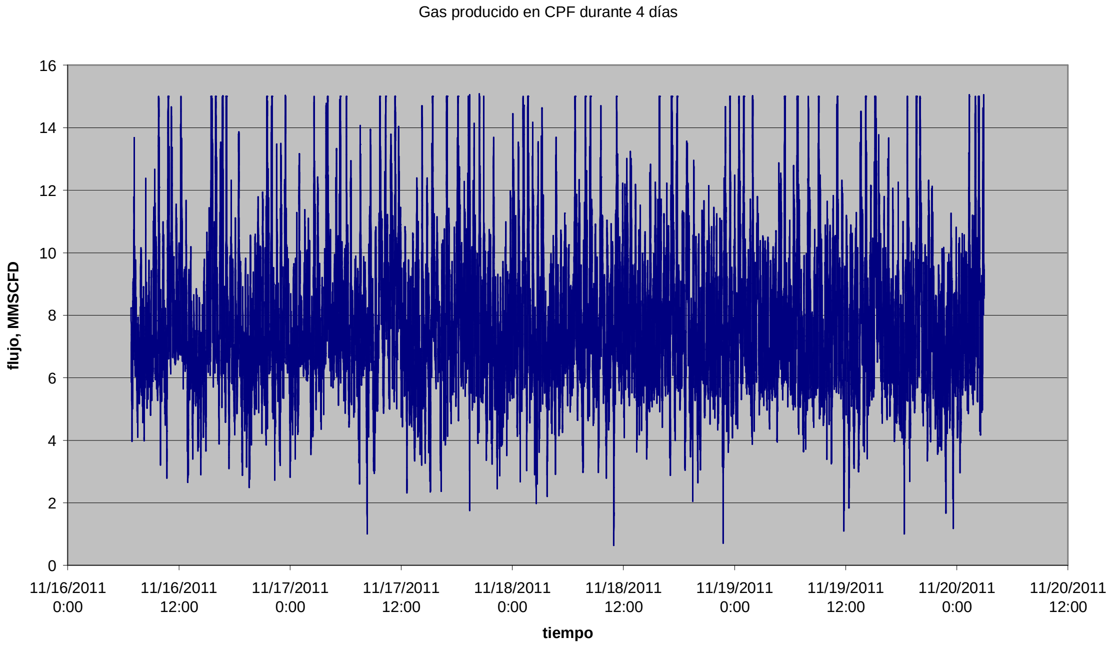


Chart No. 1: Sample associated gas production trend at CPF (volume)

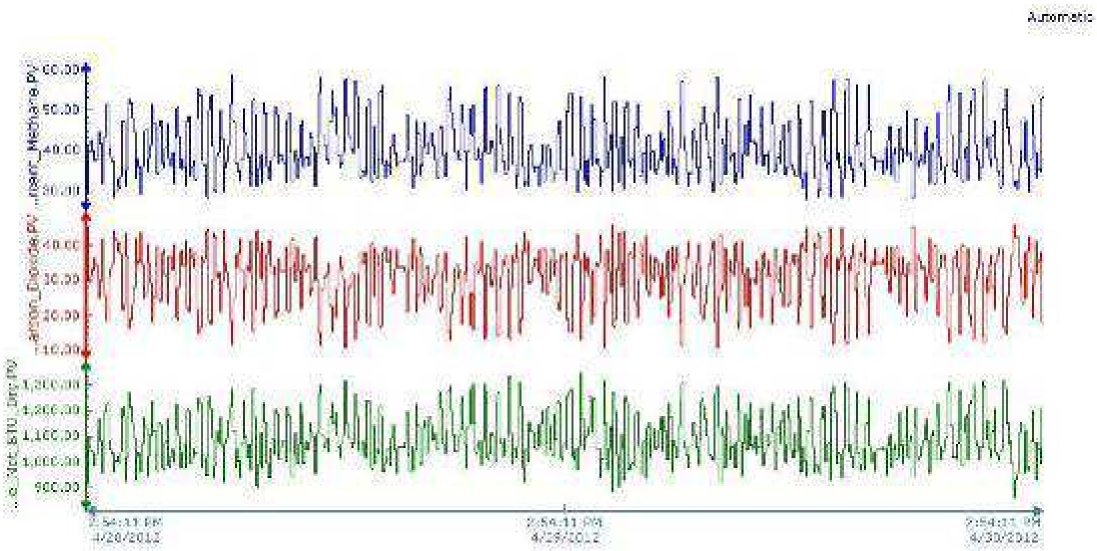


Chart No. 2: Sample associated gas production trend at CPF (composition)

B. TECHNOLOGIES IN PLACE PRIOR TO PROJECT ACTIVITY

Most power at the Block 15 and Block 31 prior to the Project Activity, was generated with power generating infrastructure burning liquid fossil fuels (diesel and crude oil); please refer to "TECNA Report Energy Matrix Summary 2008".

- EDEN YUTURI (also referred to as EY): Prior to the Project Activity power was generated with crude oil. To cover future demand new crude oil power generation equipment had been purchased without giving any thought to optimizing associated gas. All well islands were connected to a power distribution system.
- ILYP (INDILLANA, LIMONCOCHA, YANAQUINCHA and PAKA SUR): Prior to the Project Activity power generation was decentralized with each well island and production facility powered by diesel power generation units. Diesel was purchased from PETROCOMERCIAL and the rest was produced in a Topping Plant owned and operated by PETROAMAZONAS EP. The topping plant uses crude oil produced by PETROAMAZONAS EP as feedstock without any transaction/cost. To be clear, any associated gas used by the topping plant is not part of the project activity and not factored into the CER production estimation. The volume of associated gas used by the topping plant is only 0.15 mmscfpd (information supplied by engineering company and validated by DNV), which, compared to the total associated gas volume considered under the project activity (approximately 12 mmscfpd) is negligible (1.25%).

Given the fact that power was generated at each well island using diesel the only infrastructure required, under these circumstances, is the power generation equipment, electrical distribution switchgear and a diesel storage tank. The benefit of this power generation system being that units can be added and subtracted based on the actual requirements. In general the oil industry looks for short term solutions due to the uncertain nature of the business and the fact that in many cases the term of the concession is shorter than the time needed to amortize the capital intensive equipment.

In both EDEN YUTURI and ILYP associated gas is flared (see Picture No. 1) since there is no market for this "waste product". The previous operator initiated a gas optimization effort as a result of which it purchased mainly used gas power generation equipment (some diesel engines converted to gas). Prior to the Project Activity all of these efforts had come to a grinding halt due to the fact that they were not able to overcome the technical challenges listed above, abandoning the equipment that had been purchased (see pictures No. 2, No. 3 and No. 4). This gas power generation equipment was replaced by diesel generation equipment and some equipment was left in extreme deteriorated conditions (see Pictures and Table below). Under the Project Activity, these decommissioned units will be rehabilitated and taken back into use.

Picture No. 2: Abandoned gas engines.

Picture No. 3: Abandoned gas engines.

Picture No. 4: Abandoned gas engines.

Model	Field	TAG	Status / Project Activity Action
Caterpillar 3516	Indillana	G 301-1, G 101-2, 3, 4, 5	These generators only operated for a short period of time and were taken out of operation by previous operator of the oil field due to lack of reliability and inability to burn associated gas. Once taken out of operations these engines were immediately replaced by diesel generators.
Waukesha VHP 7100	Indillana	MG 102, MG 103, MG 101-9 and MG 301-3	• The MG 101-9 was operating in extreme deteriorated conditions. Part of the Project Activity is to upgrade this power generation equipment. • The MG 102, MG 103 and the MG 301-3 were not operational prior to Project Activity and as such had never operated reliably. A complete rehabilitation / upgrade program is part of the Project Activity.
Waukesha VHP 9500	Indillana	MG 101-7G and MG 101-8G	• Prior to Project Activity these had suffered a major failure and were taken off their foundations to be sold as scrap.
Waukesha VHP 5900	Limoncocha	MG 2101-1G, MG 2101-2G, MG 2101-3G, MG 2101-4G, MG 2101-5G and MG 2101-6G	• These generators were operating in extreme deteriorated conditions. Part of the Project Activity is to rehabilitate / upgrade these power generation units.
Caterpillar 3516	Limoncocha	MG 2101-7G and MG 2101- 8 G	• These generators only operated for a short period of time and were taken out of operation during the initial phase of the Project Activity due to the fact that it was apparent that this engine model cannot run reliably on associated gas. Once taken out of operations these engines were immediately replaced by diesel generators
Waukesha AT 27	Limoncocha	MG 2101-9G and MG 2101-10G	• There engines were installed by the previous operator but in a later stage it became apparent that this engine type is not suitable to operate on associated gas. Part of the Project Activity is to remove these generator sets and replace them with engines capable of running on associated gas.
Wartsila 18V34SG	Eden Yuturi	ZAN 106, ZAN 107 and ZAN 108	• These engines are designed to run on “pipeline-quality” gas but not on associated gas. Considerable investments will be made as part of the Project Activity on gas handling, gas treatment and engine “upgrade package”.

In conclusion, the technical solution in place at the time of the start of the Project Activity was based on diesel power generation and existing and new crude oil power generation equipment. All gas-based equipment was being dismantled and scrapped. Subsequently gas-based technologies are not part of the baseline which is also reflected in the baseline scenario analysis in section B.4.

C. TECHNOLOGIES IMPLEMENTED UNDER THE PROJECT ACTIVITY

The gas optimization project competes for funds with a variety of oil enhancement / production facilities whereby the following has to be taken into consideration:

i. PETROAMAZONAS EP already has existing power generation facilities with sufficient capacity to meet existing and future power demand. It should be noted that, based on the overall oil production forecast, the overall demand is expected to drop.
ii. Flaring (“business as usual”) is a feasible option, which requires no additional investment and thus the most economically attractive option.
iii. Overcoming the technical hurdles to develop gas gathering and handling facilities requires new capital.

Under the Project Activity GHG emission reductions will be achieved by i) recovering the associated gas that comes from the Block 15 and Block 31, ii) implementing infrastructure to process and handle the associated gas at the various locations, iii) put in use power generating equipment that can generate power with the available associated gas and iv) put in place power distribution facilities to transport the power to the various end consumers (well islands, processing facilities, pumping facilities, etc.).

The capacity to be installed is a factor of:

- Associated gas volume forecast (linked to the crude oil production forecast).
- Power demand forecast (linked to crude oil and water production forecast).

The Project Activity has three main phases:

Installed capacity, kW	PHASE I	PHASE II	PHASE III	TOTAL
ILYP	10,150	13,000	6,000	29,150
EY	-	20,000	13,500	33,500
TOTAL	**10,150**	**33,000**	**19,500**	**62,650**

Table No. 1: Project Activity installed capacity

The above data is a summary of the ”Inventory Gas Power Generation Equipment Project Activity” (see Annex 5) and is based on most recent estimates taking into account the dynamics of gas supply.

The information in the ”Inventory Gas Power Generation Equipment Project Activity” can suffer modifications, namely, demands, and subsequent installed capacity, are subject to continuous variations inherent to the nature and dynamics (uncertainty) of the petroleum industry. PETROAMAZONAS EP therefore cannot guarantee that the attached configuration is definitive (except for the capacity that has already been installed) whereby it actually has opted for modular design to enable it to respond

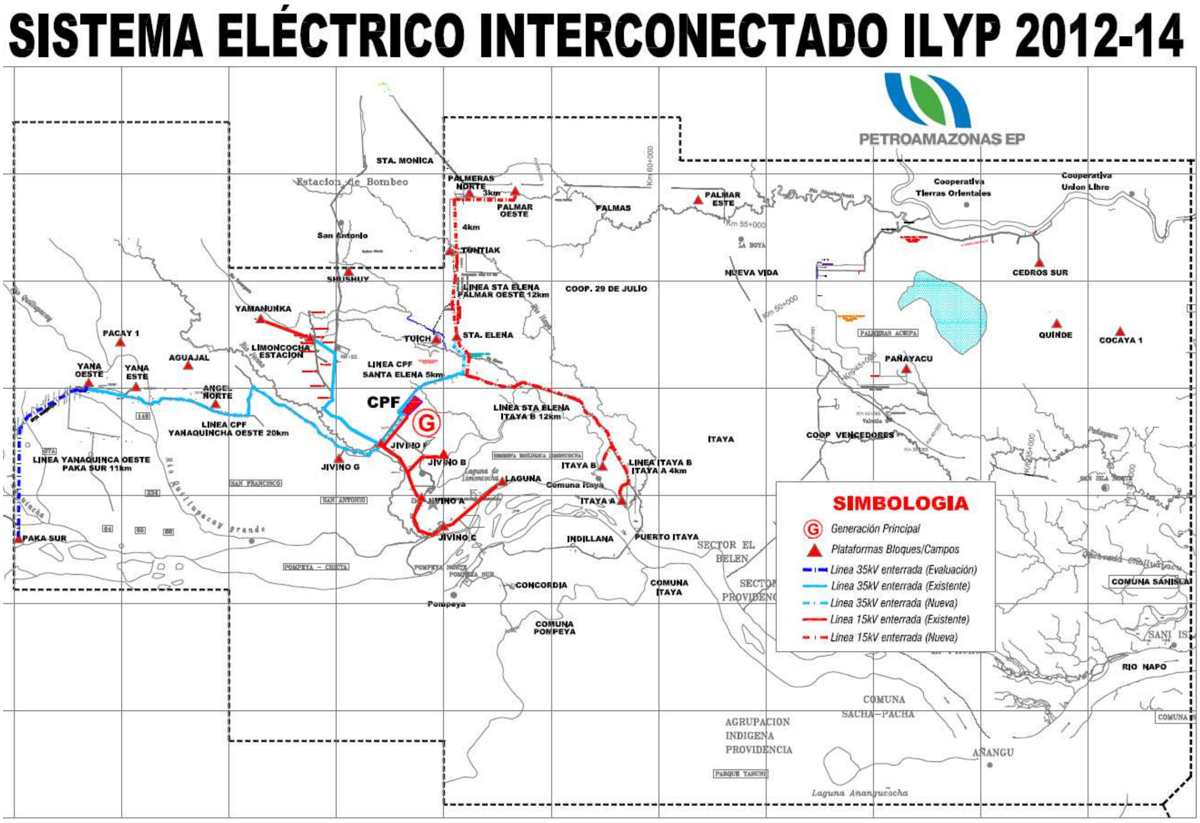
adequately to the continuous variations (modular design facilities demobilization and mobilization of power units and corresponding auxiliary equipment thereby reducing / mitigating certain risks).

As is today, the total projected installed capacity running on associated gas will reach approximately 62 MW whereby the operating capacity, subject to the availability and characteristics of associated gas will be approximately 50 MW. There are many variables not under control of PETROAMAZONAS EP that have an impact on both power demand and availability / composition of associated gas (starting with actual production versus forecast and subsequently Gas Oil Ratio and corresponding gas quality) to enable it to make definitive statements. When dealing with natural gas the scenario is different since one can count on a stable fuel supply both in terms of quantity and quality. The Project scenario is nevertheless quite different in that it has to cope with a "waste product" that, both terms of quantity and quality, is unpredictable (see Chart No. 1 and 2).

The power deficit between power demand and potential power generation with associated gas will be generated by the following setup:
- Interconnected areas: Deficit generated with crude oil or residual fuel. For this PETROAMAZONAS plans to install a crude power generation facility.
- Remote areas (not interconnected): Power generated with diesel.
- As back-up to the associated gas power generation facilities PETROAMAZONAS EP will maintain operational the existing diesel and crude oil generation facilities.

The main technological components of the proposed Project Activity are:
- Gas gathering facilities.
- Gas processing (compression and treatment) facilities.
- Power generation facilities (upgrade / new equipment).
- Conversion engine drivers to electrical motors.
- Electric distribution systems (switchgear, substations, distribution lines, etc.).

Further on some Project Activity information:
- Map No. 2 lays out how the different locations in ILYP will be interconnected (today they each have their own power generation facility).
- Figure No. 1 shows a typical gas handling facility.
- Table No. 2 indicates the auxiliary equipment installed by the Project Activity.



Map No. 2: Power Distribution System ILYP

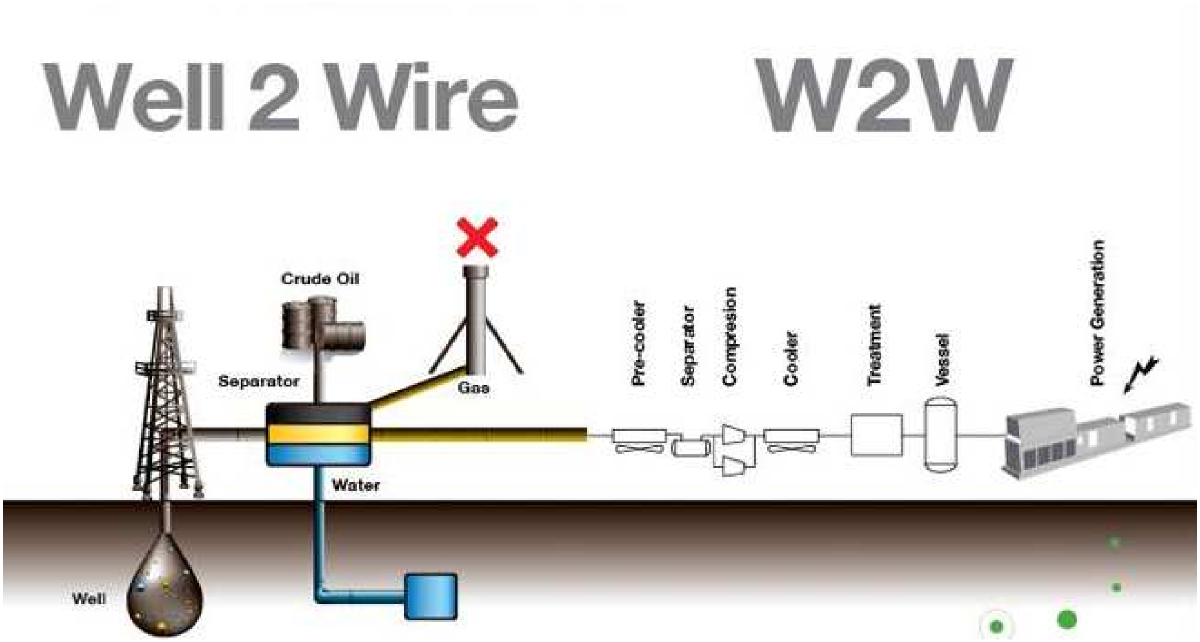


Figure No. 1: Well 2 Wire facilities

Item	Location	Equipment	Approximate Load (kW)	Gas Handling Capacity (mmcfpd)
1	CPF	Pre-Cooler No. 1	31	
2	CPF	Pre-Cooler No. 2	31	
3	CPF	Compressor Down Stream Separators No. 1	376	3.50
4	CPF	Compressor Down Stream Separators No. 2	376	3.50
5	CPF	Compressor Down Stream Separators No. 3	Stand-by	
6	CPF	Gas Plant to Adjust Dew Point	125	
7	CPF	Low Pressure Compressor No. 1	282	3.50
8	CPF	Low Pressure Compressor No. 2	Stand-by	
9	CPF	Gas Heater	43	
10	CPF	Condensate Pumps	13	
11	CPF	Condensate Stabilization Plant	31	
12	Limoncocha	Pre-Cooler No. 1	27	
13	Limoncocha	Pre-Cooler No. 2	Stand-by	
14	Limoncocha	Compressor Down Stream Separators No. 1	94	1.50
15	Limoncocha	Compressor Down Stream Separators No. 2	94	1.50
16	Limoncocha	Compressor Down Stream Separators No. 3	Stand-by	
17	Limoncocha	Gas Heater	36	
18	Paka Sur	Pre-Cooler No. 1	9	
19	Paka Sur	Compressor Down Stream Separator No. 1	94	1.50
20	Paka Sur	Compressor Down Stream Separator No. 2	Stand-by	
21	Paka Sur	After Cooler	9	
22	Paka Sur	Gas Plant to Adjust Dew Point	13	
23	Eden Yuturi	Pre-Cooler No. 1	9	
24	Eden Yuturi	Pre-Cooler No. 2	9	
25	Eden Yuturi	Compressor HP Down Stream Separators No. 1	626	3.50
26	Eden Yuturi	Compressor HP Down Stream Separators No. 2	626	3.50
27	Eden Yuturi	Low Pressure Compressor No. 1	282	3.00
28	Eden Yuturi	Low Pressure Compressor No. 2	Stand-by	
29	Eden Yuturi	Condensate Pumps No. 1	75	
30	Eden Yuturi	Condensate Pumps No. 2	Stand-by	
31	Eden Yuturi	Compressor HP Down Stream Separators No. 1	157	
32	Eden Yuturi	Compressor HP Down Stream Separators No. 2	157	
33	Eden Yuturi	Compressor HP Down Stream Separators No. 3	Stand-by	
34	Eden Yuturi	Gas Plant to Adjust Dew Point	44	
35	Eden Yuturi	Gas Heater No. 1	43	
36	Eden Yuturi	Gas Heater No. 2		
37	**BLOQUE 15**	**TOTAL LOAD PROJECT ACTIVITY ("Parasitic Load")**	**3,711**	
38	BLOQUE 15	Gas Handling Capacity (mmpcpd)	20	25.00

Table No. 2: Project Activity auxiliary equipment

D. ROLE OF TECHNOLOGY TRANSFER

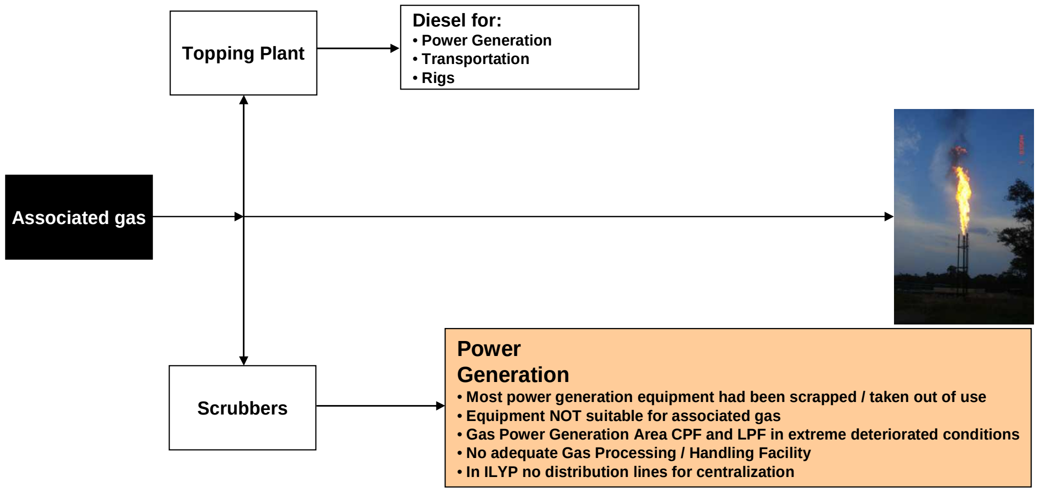
The Project Activity will use 'state of the art' environment-friendly technology ranging from:

- JENBACHER GE generator sets capable of running on associated gas.
- WAUKESHA GE generator sets capable of running on associated gas.
- WARTSILA Gas / Crude engines to cover the range where associated gas supply is not guaranteed.

E. SUMMARY OF TECHNOLOGICAL ALTERNATIVES

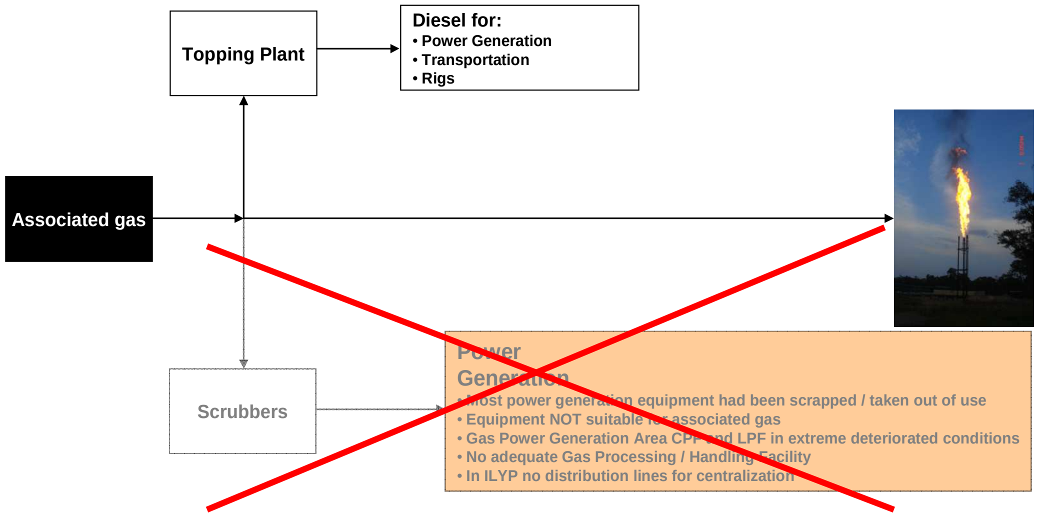
A general overview of the technical solutions under: i) Prior Project Activity, ii) Baseline Scenario and iii) Project Activity are shown further on:

PETROAMAZONAS
Prior to the Project Activity



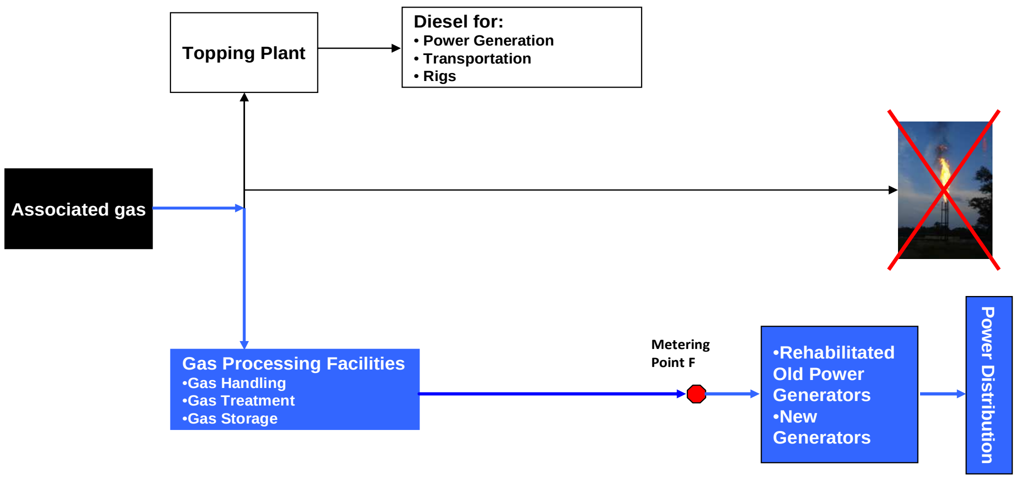
PETROAMAZONAS invested close to USD 50,000,000 in diesel and Crude oil power generation equipment to convert to 100% power generation Liquid fuels.

PETROAMAZONAS
Base Line



Due to: i) extreme poor reliability and conditions of gas power generation facilities, ii) lack of gas processing / handling facilities and iii) decision of management to go with diesel / crude oil power generation facility the Base Line scenario is running 100% of power demand with liquid fuel.

PETROAMAZONAS
Project Activity



Due to: i) extreme poor reliability and conditions of gas power generation facilities, ii) lack of gas processing / handling facilities and iii) decision of management to go with diesel / crude oil power generation facility the Base Line scenario is running 100% of power demand with liquid fuel.

Please refer to Annex 5 for detailed information concerning the situation existed before the project and planned project activities.

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

This proposed Project Activity will request a crediting period of 10 years whereby it is expected that the net GHG emissions will be reduced by approximately 923,071 tons CO_2 equivalents.

Years	Annual estimation of emission reductions (tons of CO_{2e})
From 2013-01-01 to 2013-12-31	188,209
From 2014-01-01 to 2014-12-31	154,312
From 2015-01-01 to 2015-12-31	123,133
From 2016-01-01 to 2016-12-31	101,330
From 2017-01-01 to 2017-12-31	87,546
From 2018-01-01 to 2018-12-31	70,864
From 2019-01-01 to 2019-12-31	65,385
From 2020-01-01 to 2020-12-31	53,337
From 2021-01-01 to 2021-12-31	43,977
From 2022-01-01 to 2022-12-31	34,977
Total estimated reductions (tons of CO_{2e})	**923,071**
Total number of crediting years	**10**
Annual average of estimated emission reduction over the crediting period	**92,307**

A.4.5. Public Funding of the Project Activity:

There is no public funding under Official Development Assistance (ODA) from Annex-I countries available for the proposed Project Activity.

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:

The Project Activity is developed with reference to the approved methodology AM0009 Version 05.0.1 - "Recovery and utilization of gas from oil wells that would otherwise be flared or vented".

B.2. Justification of the choice of the methodology and why it is applicable to the Project Activity:

The AM0009 Version 05.0.1 "Recovery and Utilization of Gas from oil wells that would otherwise be flared or vented" is applicable to the Project Activity because it meets the specific applicability conditions of the methodology:

Applicability Criteria	Justification
Under the Project Activity the recovered gas after the pre-treatment (compression and phase separation) in movable or stationary equipment is: - Consumed on-site to meet energy demands; and/or - Transported to a gas pipeline without prior processing; and/or - Transported to a processing plant where it is processed into hydrocarbon products (e.g. dry gas, LPG and condensates). The dry gas is either (i) transported to a gas pipeline directly, or (ii) compressed to CNG first, then transported by trailers/trucks/carriers and then decompressed and gasified again, before it finally enters the gas pipeline .	The associated gas will be used to produce electricity to meet own energy demand, therefore this criterion is applicable.
The project activity does not lead to changes in the process of oil-production, such as an increase in the quantity or quality of oil extracted, in the oil-wells within the project boundaries.	The Proposed Activity is only to recover and utilize the associated gas that was previously flared and will not lead to any changes in the volume or composition of oil or high-pressure gas extracted at the production site. The Project Activity indeed neither improves the quality nor increases the volume of crude oil production since it takes place downstream of any oil production and or processing activity and therefore cannot enhance oil-production. In case associated gas was to be re-injected this could lead to enhanced oil production but this is not the case for this Project Activity.

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.	The Block 15 and Block 31 have not injected gas into the oil reservoirs for enhanced oil production in previous years nor is such project being considered at this time.
All recovered gas comes from oil wells that are in operation and are producing oil at the time of the recovery of the associated gas and/or gas-lift gas.	The Project Activity only considers associated gas from wells producing oil at the time of the recovery. Within the Blocks operated by PETROAMAZONAS there are no gas wells / fields and 100% of the gas is associated gas extracted from the reservoirs with crude oil and water. The provided list of wells demonstrates that that none of them are exclusively gas or gas-water wells within the project boundaries.
Finally, the methodology is only applicable if the identified baseline scenario is: 1) 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 2) The continued operation of the existing oil and gas infrastructure without any other significant changes (scenario P4); and 3) In the case where gas-lift is used under the project activity: the gas-lift gas under the baseline uses the same source as under the project activity and the same quantity as under the project activity (scenario 01).	1) All associated gas would be flared in absence of the project implementation. Please refer to the baseline identification section, scenario G2. 2) The most probable baseline scenario is the practice that existed before the Project implementation i.e. continued power generation with liquid fossil fuel without processing recovered gas and without any other significant changes. Please refer to the baseline identification section, scenario P4. 3) Is not applicable since the Project does not involve gas-lift.

As it is demonstrated in the table above AM0009 version 05.0.1 is fully applicable.

B.3. Description of the sources and gases included in the Project Boundary:

The Project Boundary encompasses:

- The project oil reservoirs of PETROAMAZONAS EP where the associated gas is collected in Block 15 and Block 31 (see Map No. 1);
- The site where the associated gas was or would be flared in the absence of the Project Activity, which in this case is at the Block 15 and Block 31 (see Map No. 1);
- The gas recovery, processing and handling (compression, treatment, buffer, etc) at the Block 15.

The proposed Project Activity comprises of new gas processing facilities and power generation and distribution facilities whereby the recovered associated gas will be treated to:

(i) Withdraw excess CO_2 to meet minimum Lower Heating Value (LHV) standards (in fields where the gas has a high enough LHV CO_2 removal is not required); and,

(ii) Withdraw the condensates that inhibit power generation equipment from generating with gas; and,

(iii) Condition (composition and pressure) the associated gas to convert it into fuel gas for power generation whereby certain minimum parameters apply in terms of LVH, pressure, octane number, etc.

(iv) Compress gas and store certain volumes in recipients to create a minimum buffer to compensate for unstable supply.

The GHGs included in or excluded from the Project Boundary are shown in the following table (see also Fig. No. 1):

Source		Gas	Included?	Justification / Explanation
Baseline	Combustion of fossil fuels at end-users that are produced from non-associated gas or other fossil sources	CO_2	Yes	Main source of emissions in the baseline. Emissions from combustion of fossil fuels used for power generation
		CH_4	No	Excluded for simplification. This is conservative. To be conservative it is assumed that the flaring system has a 100% destruction efficiency.
		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	Emissions due to the use of energy that is produced by other fossil sources.
		CH_4	No	Excluded for simplification. This emission source is assumed negligible. .
		N_2O	No	Excluded for simplification. This emission source is assumed negligible.

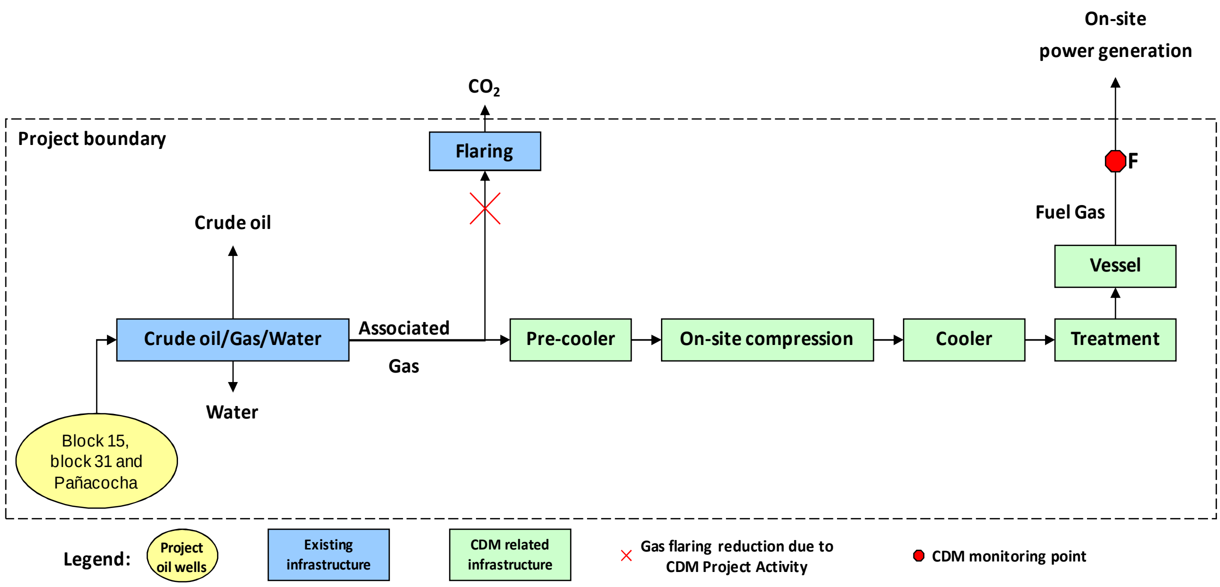


Figure No. 2: Schematic view of the Project Boundary (as per Methodology AM0009/Version 05.0.1 related to the emissions) and monitoring point.

B.4. Description of how the Baseline Scenario is identified and description of the identified Baseline Scenario:

According to the methodology, the following plausible alternative scenarios should be considered:

Plausible alternative baseline scenarios for the associated gas and/or gas-lift gas from the project oil wells:

G1: Release of the associated gas into the atmosphere at the oil production site (venting)	Gas venting (or flaring) is subject to authorization according to the law[4]. Flaring is the normal practice at PETROAMAZONAS EP´s facilities today due to the following reasons: venting of associated gas in the available quantities would be dangerous both to operators due to a risk of explosion and to environment due to contamination. As demonstrated to DNV during the site visit, flaring is the common practice followed by PAM (please see "Annual authorization for the use and burning of gas at the Block 15, 2008" and "Authorization of use and flaring of associated gas at PETROAMAZONAS EP operations, 2009") whereby venting is not considered as an alternative baseline scenario.
G2: Flaring of the associated gas at the oil production site	At the Project Activity sites, gas has been flared since the start of operation of the fields. There are

[4] Ley de Hidrocarburos

	no regulations preventing PETROAMAZONAS EP from continuing to flare the gas. Moreover, gas flaring is widely applied in the Ecuadorian Oil industry. The Ministry of Electricity and Renewable Energy illustrates that approximately 80% of the associated gas is flared (see details in "Strategic policies to change the energy matrix"). In other words, there is no incentive to change the current practice. Therefore, this alternative is viable.
G3: On-site use of the partial amount of associated gas to meet on-site energy (demand) and rest of the gas are either vented (G1) or flared (G2);	One of the key arguments supporting the decision to proceed with the Project Activity was that, without the Project Activity, the conditions and solutions were not in place to use Associated Gas for power generation. This is supported by that the fact that, prior to the Project Activity the Project Developer had invested over USD 50,000,000 in power generation equipment solely based on diesel and crude oil (see Section A.4.3 E Summary of the Technological Alternatives).
G4: Injection of the associated gas into an oil or gas reservoir	Since there is no standard geological structure there is no guarantee that gas injection will always lead to improvement in oil production rates. Each field must be evaluated on a case-by-case basis for suitability of gas injection. In other words, there is no certainty that gas injection at the Block 15 and Block 31 will enhance oil recovery. Furthermore, the Block 15 and Block 31 produce a relatively small volume of associated gas, which must be offset against the fact that gas injection is a technically complex process and capital and energy intensive. Therefore, this option is not viable.
G5:The proposed Project Activity without being registered as a CDM project activity	This alternative corresponds with the proposed project and is very similar to scenario G3. This alternative is not viable as this is demonstrated below in Section B.5.
G6: Recovery, transportation and utilization of the associated gas as feedstock for manufacturing of useful products	This option is not a realistic, as Ecuador currently does not have the petrochemical industry where associated gas could serve as a feedstock. Therefore, the option is not a viable baseline scenario.

From the scenarios identified and evaluated above, only one scenario is considered as realistic and viable:

G 2: Flaring of the associated gas at the oil production site

Plausible alternative baseline scenarios for oil and gas infrastructure:

P1: Construction of a processing plant for processing the recovered gas, in the same way as in the project activity, without being registered as a CDM project activity	This alternative corresponds to the proposed Project Activity and below in section B.5. it is demonstrated that this option is not viable without the benefits of CDM.
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	This alternative is not viable, apart from associated gas from the Block 15 and Block 31; there are no other sources of gas.
P3: Supplying recovered gas to an existing gas processing plant and constructing the necessary infrastructure, without being registered as a CDM project activity	Associated gas could be transported in a pipeline (around 30 km.) to the Shushufindi Facilities of PETROINDUSTRIAL. Nonetheless, this is not a feasible option for the following reasons: – PETROAMAZONAS EP cannot guarantee a long term gas volume and gas composition to justify the investment for the infra-structure required to take the gas from its facilities to the processing plant at Shushufindi whereby this plant precisely requires a stable and long-lasting supply. – Since the Project Activity decision is made based on a company level cost / benefit analysis sending associated gas to the processing plant would not obtain budget approval since it generates neither savings nor income to PETROAMAZONAS EP. – At some point the alternative was evaluated to receive residual gas in exchange for raw gas to be used as power generation but, based on the engineering study undertaken in 2008/2009 by TECNA, the residual gas received back from processing plant would be of such poor quality that it would not meet minimum requirements (such as LHV) for power generation. – Building infrastructure outside the Geographic Project Boundaries would require a special authorization / mandate from the Government of Ecuador. Existing by-laws require for PETROAMAZONAS EP to focus its resources on operating the corresponding oil production facilities. – There are no guarantees that the depreciation of gas transportation facilities can be matched with the “lifetime” of the production facility at CPF and LIMONCOCHA. The previous creates a significant risk of ending up with a “stranded asset”.
P4: Continuation of the operation of the existing	No additional infrastructure is needed to continue

oil and gas infrastructure without any other significant changes	flaring associated gas from the various fields. For this reason, this is a viable alternative under the assumption that PETROAMAZONAS would not develop the CDM Project Activity.
P5: Supplying recovered gas to a gas pipeline without prior processing and without being registered as a CDM project activity	For the same reasons as indicated for alternative P3, this alternative is not a viable.

From the scenarios identified and evaluated above, only one scenario is considered to be realistic and viable:

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.

Plausible alternative baseline scenarios for the use of gas-lift: this is not applicable as there is not gas-lift used under the project activity.

Based on the considered alternative the baseline was identified as G2 (Flaring of the associated gas at the oil production site) and 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) in other words, the situation existed before the project implementation.

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):

Prior consideration of CDM

On February 12, 2009 the Initial Budget for the Project Activity was approved by PETROAMAZONAS EP and the Ministry of Finance whereby this date is considered the Project Activity Starting Date since as of that date funds were available to implement the Project Activity. CDM benefits were a key component of the Conceptual and Detailed Engineering (such as monitoring equipment) of the Project Activity that formed the basis for the budget allocation.

Additional activities / actions undertaken by PETROAMAZONAS EP related to CDM Project Activities are laid out below:

- *March 2009:* Based on the initial study by Power Latin America Inc. PETROAMAZONAS hired an "in-house" CDM officer/specialist to address CDM registration of the OGE Project.
- *March 18, 2009*: PETROAMAZONAS submitted an official letter to the Ministry of the Environment (the Ecuadorian DNA) to inform its intentions to develop the CDM Project Activity and its intention to seek CDM status. Approximately one month later, the DNA confirmed receipt of PETROAMAZONAS letter indicating that it would support Project Activities with the objective to grant National Approval Status.

Identification of the baseline scenario and demonstration of additionality

For identifying the baseline scenario, the procedure laid out in methodology AM0009 "Recovery and utilization of gas from oil wells that would otherwise be flared or vented" was applied.

In general terms, this analysis requires:

a) Step 1: Identification of all the plausible alternative scenarios
b) Step 2: Evaluation of legal aspects
c) Step 3: Evaluation of the economic attractiveness of alternatives
d) Step 4: Common practice analysis

Apart from the Additionality tool, indicated in the "Tool for the demonstration and assessment of additionality" (Version 6.0.0), it is also using the Additionality approach included in the AM0009 methodology whereby it is assumed that both are mandatory.

STEP 1: IDENTIFY PLAUSIBLE ALTERNATIVE SCENARIOS

The previous section identified the Baseline Scenario. In addition the Project Scenario without being registered as a CDM project should be considered a viable alternative.

STEP 2: EVALUATE LEGAL ASPECTS

From the scenarios identified and evaluated above, two scenarios are considered realistic and viable; whereby, a legal assessment is made to demonstrate compliance of these alternatives:

- 1 i.e. the Baseline scenario i.e. G2 and P4 and
- 2 i.e. the Project Scenario i.e. G3, G8 and P1.

The laws that related to the use of associated gas are laid out in the Hydrocarbons Law *(Ley de Hidrocarburos)* Articles 34, 35, 36, 39, and 41. In general, oil companies (operators) can use associated gas for their operations upon obtaining approval from the National Directorate of Hydrocarbons (DNH)[5]. Some oil companies in Ecuador use associated gas for power generation in locations where there are no technical barriers and or under circumstances where from the initial "drawing board" phase associated gas optimization was one of the project design criteria (considering "green field" projects).

Article 34 complicates the commercialization of flare gas by stipulating that natural gas obtained from exploitation of oil deposits belongs to the State and can only be used by the contractors or associates in the quantities necessary for operation of exploitation and transport or for re-injection in the deposits after previous authorization from the Ministry of Oil and Mining. In condensate fields or deposits with a high gas to oil relation, the Ministry of Oil and Mining can demand recirculation of the gas.

Sale of excess gas is addressed by Article 35. It states that the State of Ecuador, through e.g. PETROECUADOR, can enter into additional contracts with its respective contractors or associates or into new contracts with other entities with a recognized technical and financial capacity to use the gas derived from the oil deposits for industrial or commercial use. PETROECUADOR can also extract the liquefiable hydrocarbons from the gas extracted by the contractors or associates.

Article 36 states that if PETROECUADOR wants the gas for industrial purposes, generation of electricity, commercial use, or any other use, contractors or associates shall at no cost hand over to PETROECUADOR the gas they extract and do not use for their own production purpose. In such cases, PETROECUADOR will only pay the transfer cost incurred by the contractor or associates.

Given the legal framework, both baseline scenarios are clearly permitted by law therefore making them legally viable baseline alternatives. Furthermore, alternative (2) is also covered by an approved ex-post Environmental Impact Assessment or Internal Environmental Audit, which is required to comply with the Environmental Law (see Section D).

In conclusion, alternative scenarios (1) and (2) comply with all applicable legal and regulatory requirements. Thereby it is feasible to proceed with the economic evaluation of the alternatives.

<u>STEP 3: EVALUATING THE ECONOMIC ATTRACTIVENESS OF THE ALTERNATIVES</u>

The economic attractiveness is assessed for those alternative scenarios that are feasible in technical terms and that were identified as being permitted by law in Step 2. The economic attractiveness is assessed by determining an expected Internal Rate of Return (IRR) or Net Present Value (NPV) of each alternative scenario, following the guidance for the investment analysis in the latest approved version of the "Tool

[5] The Directorate is responsible for the development and implementation of the country's hydrocarbon policy and for enforcing the Hydrocarbon Law. It can introduce regulations needed for the appropriate implementation of the law. The Directorate approves or authorizes all phases of the hydrocarbon activities, including the oil companies' plans and budgets for investment; sets limits for oil production; authorizes and monitors the construction of oil and gas pipelines; and controls and monitors the market for LPG. Revenues derived from permits, sale of information, and fines finance the Ministry's administration.

for the demonstration and assessment of additionality – version 6.0.0”. The IRR will be determined using the following parameters as applicable to the relevant scenario:

- Overall projected production of associated gas based on the oil production forecasts.
- The projected quantity of gas recovered, gas flared, consumed on-site, processed in a gas handling / processing plant to meet energy demands.
- The net calorific value of the recovered gas.
- Capital expenditure for all power generation, power distribution and gas infrastructure needed in the relevant scenario (CAPEX). For more detail, see Table No. 3 Section A.4.3.
- All operational expenditure associated with the respective scenario (OPEX).
- Any cost recovery, such as cost savings through the substitution of products by the recovered gas as the substitution of diesel by associated gas.
- Residual value of machinery and equipment.

It is important to note that there is not an agreed upon price for associated gas in Ecuador, as it is generally flared; therefore, the gas has no monetary value.

Guidance in the Additionality Tool emphasizes the need to consider incremental cash flows at the time of investment decision accruing to the project proponent. The investment analysis focuses on the core decision made by PETROAMAZONAS EPs’ management to initiate the Project Activity. This decision was made in awareness of PETROAMAZONAS EPs’ by-laws and operating licence under which the price consideration received by PETROAMAZONAS EP for the transfer of its oil production to the State of Ecuador is determined in function of the oil production cost (see further below). In other words, PETROAMAZONAS EP has no legal right to sell any of the oil it produces. The on-site self consumption of crude oil for power generation, and in particular the reduction of this consumption as a result of the recovery of associated gas resulting from the Project Activity, has no direct or indirect benefit to PETROAMAZONAS EP and thus it is excluded from the IRR analysis in line with the additionality tool and investment appraisal guidance:

- On the one hand, crude oil used for on-site power generation is a self consumption for PETROAMAZONAS EP and has never been treated as a cost. PETROAMAZONAS EP is authorized by national regulations and its operating licence to use this crude oil for the need of its production operations at no cost;
- On the other hand, reducing this on-site self consumption has a neutral effect on PETROAMAZONAS EP’s financial resources as these resources are determined in function of the production costs in accordance with PETROAMAZONAS EP’s operating licence. In other words, the reduced self-consumption will not impact PETROAMAZONAS EP as the latter is compensated for its oil transfer to the State in function of its costs and not in function of market prices[6].

Tool guidance: Sub-step 2b: Option II, Apply benchmark analysis indicates the following:

- *(4) “Identify the financial/economic indicator, such as IRR, most suitable for the project type”*

[6] In a similar instance, where the price of crude oil delivered by a producer was fixed on the basis of regulations, and not on the basis of the market price, it was considered that price assumptions based on regulations are deemed adequate, and that revenues from cost savings through the substitution of products by the recovered gas could be determined on the basis of these regulations rather than (world) market prices as these are not applicable for the project activity (see project 2908, PDD p. 28 and 29, http://cdm.unfccc.int/Projects/DB/RWTUV1249652203.75/view).

- *(5)" When applying Option II or Option III, the financial/economic analysis shall be based on parameters that are standard in the market, considering the specific characteristics of the project type, but not linked to the subjective profitability expectation or risk profile of a particular project developer. Only in the particular case where the Project Activity can be implemented by the project participant, the specific financial/economic situation of the company undertaking the Project Activity can be considered. For example, when the Project Activity upgrades an existing process or uses a resource (i.e. some waste) available on the project site and that is not traded.*

Critical to analyzing, and consequently determining the economic parameters of the alternative scenarios, are the following considerations:

A. Overall projected production of associated gas:

The projected associated gas production depends on the volume of crude oil and the expected ratio of crude oil / associated gas. The gas production estimates used for the Project Activity are based on production forecasts from PETROAMAZONAS EP that was issued by the head of Operations in February 2009. Later on this was substituted by a forecast scenario specific for the Project Activity because previous forecast reports did not span the period of the Project Activity. It is important to point out that production forecasts are constantly updated whereby for the Project Activity the snap shot provided by the head of Operations was frozen and used for designing the Project Activity.

B. The projected quantity of gas recovered, flared and consumed on-site:

Beyond the generic factors above, the amount of gas recovered (for use) depends on the following factors influencing the gas gathering and optimization potential.

- *Power demand at site*:
  - Power demand corresponds to the total fluid production (crude oil and water). Power demand moves in line with the amount of fluids that must be handled (pumping, processing, injecting, etc.). To monitor this, PETROAMAZONAS EP tracks the ratio between the volume of fluids (crude oil and water - in Fluid Barrels per Day) and the electric power demand (kW) using a kW / BFPD ratio. This ratio is dynamic and varies depending on the total volume of oil and water, the water cut and reservoir characteristics.
- *Gas characteristics*:
  - Gas supply characteristics - gas comes in batches to the central production facilities because gas separates prematurely in the secondary gas supply lines .
  - Gas chromatography (Methane, CO_2, Butane, Propane, LHV, etc.) can vary considerably within any given period of time and definitely over time. It is not unusual to find the initial levels of CO2 in associated gas increase from 10% to 50% over time.

Chart No.3 below summarizes the gas quantities available to PETROAMAZONAS EP at the Block 15 and Block 31 based on the analysis above. From the chart, it becomes evident that the volume of available gas is not sufficient to generate 100% of the power demand. Therefore,

- PETROAMAZONAS EP has to continuously supplement power generated with associated gas with power generated with diesel and / or crude.
- PETROAMAZONAS EP cannot dispose of existing diesel and crude power generation facilities since it will again have to rely on them (i) as a back-up and (ii) as associated gas volumes deplete.

Even though the field oil production, according to production estimates, decreases over time this does not mean that power demand will decrease since power demand is related to the overall fluid (crude oil and water) that has to be processed whereby over time the water cut (water / crude oil ratio) increases.

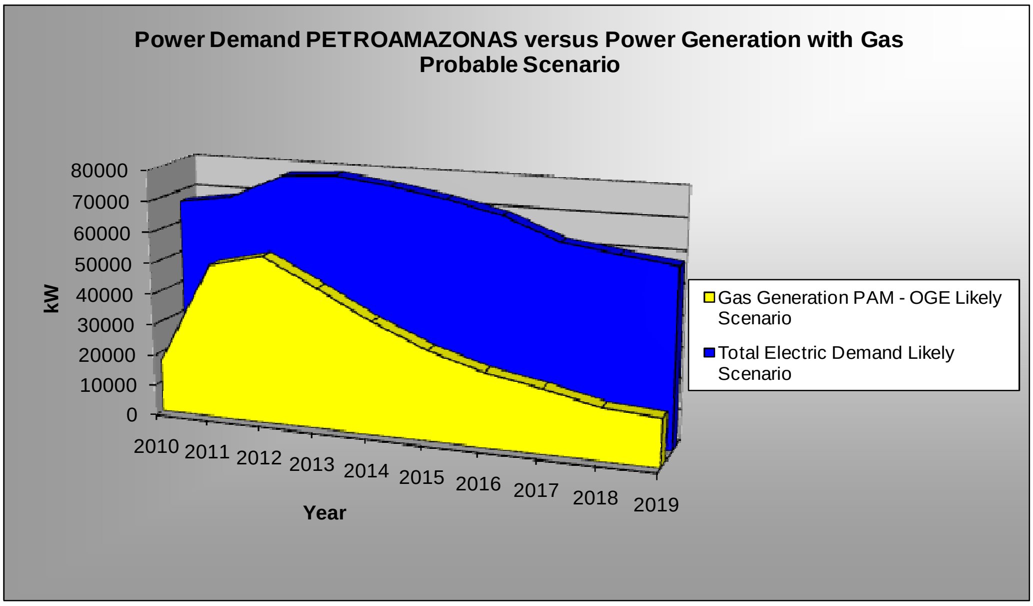


Chart No. 3: Power demand vs. potential power generation with gas Probable Scenario.

C. The net calorific value of the gas (characteristics / dynamics):

The dynamics of associated gas, and the solutions implemented to mitigate these, are determining factors in the success / failure of the proposed Project Activity. The following dynamics / variables are issues that have to be dealt with to assure the technical and economical success of the Project Activity:

- Future volume of associated gas is subject to constant variations.
- Gas supply is inherently inconsistent, meaning that gas comes in batches with significant variation between "high" and "low" volumes.

In determining the net calorific value of associated gas, the gas compositions (share of methane, CO_2, butane, propane) is essential whereby this varies overtime and sometimes even abruptly depending on which wells are on line, maturity of the fields, reservoirs that are being tapped into, etc.

D. Capital Expenditures (CAPEX):

CAPEX are the investment costs associated with the implementation of the proposed Project Activity. These total US$81.6 million. Please see Investment Schedule in the Investment Analysis for a summary of capital expenditure.

It is important to emphasize that **no** power generation equipment will be sold as a result of the Project Activity. On the contrary; new crude oil-based power generation equipment has been purchased in parallel with the Project Activity to guarantee a long-term reliable power generation source in the face of the volatility of associated gas supply.

Note: The overall investment cost not only takes into consideration power generation equipment but all other infrastructure indicated in Section A4.3.

E. Operational Expenditures (OPEX):

The Baseline Scenario represents the situation where only diesel/crude oil power generators and appropriate auxiliary equipment would be used. In the Project Activity, associated gas power generation equipment, together with the gas handling facilities, is added to meet the objectives to reduce gas flaring . By adding these facilities, together with their corresponding auxiliary and support equipment., the overall maintenance and operations complexity increases significantly. These systems range from i) gas gathering, ii) gas compression, iii) gas treatment. The Project Activity therefore does not generate any O&M savings since in essence more equipment and facilities have to be incorporated without being able to dispose of existing diesel and crude oil power generation facilities.

For purposes of conservativeness the investment analysis assumes the operating costs for the infrastructure required for the Project Activity to be equal to the operating costs in the baseline scenario.

F. Costs savings:

The Project Activity optimizes the use of recovered associated gas for power generation to meet part of the power demand for Block 15 and Block 31. The balance of power demand (shortfall) is met with power generated with liquid fuel. The economic evaluation accounts for the cost savings (avoided cost) from reduced purchases of diesel fuel for power generation. Diesel prices are regulated and fixed by the Government of Ecuador. [7] The economic analysis assumes a constant price of diesel of 0,91 USD per gallon, based on the long-term average subsidized price of diesel in Ecuador. PETROAMAZONAS EP also operates a topping plant that produces approximately 20,000 gallons per day of which approximately 80% is used for power generation. The cost of this fuel is considered zero for PETROAMAZONAS EP since it provides its own crude oil as feed stock. The amount of diesel produced by the topping plant covers roughly 30% of demand.

As explained above, PETROAMAZONAS EPs' by-laws and operating licence permit it to utilize crude oil for oil production at no cost. As a result, the reduction in consumption of crude oil for power generation will not yield any cost savings to PETROAMAZONAS EP.

G. Residual value of assets:

PETROAMAZONAS EP accounting procedures apply a 10% straight-line depreciation rate for equipment and machinery. The book value of equipment and machinery is therefore zero at the end of the lifetime.
Based on the Projects' investment budget, 61,4% of the total cost is assigned to machinery and equipment which equals US$ 50 million. A residual value of US$ 10, million is included in the investment analysis.

As explained before, the Project Activity does not create the opportunity to sell existing diesel and crude oil power generation equipment.

[7] See details at http://www.petrocomercial.com/wps/portal

H. Economic Evaluation of attractiveness of alternatives:

Baseline Alternative 1 represents the situation in which flaring of the associated gas would continue under current practices; no increase in capital expenditure is required and, no new revenue is generated. On the basis of the investment analysis guidance in "Tool for the demonstration and assessment of additionality" (V6.0.0), we will apply the benchmark analysis.

The benchmark analysis for Baseline Alternative 2 presented here is based on an IRR calculation and economic parameters used by PETROAMAZONAS EP for evaluating the feasibility of the Project Activity:

ECONOMIC PARAMETERS	
CAPEX (US$)	81,671,975
OPEX (US$)	0
AVOIDED / SAVING COSTS (US$)	80,063,846
LIFETIME (YEARS)	10
RESIDUAL BOOK VALUE OF ASSETS (US$)	10,042,566
DISCOUNT RATE (%)	16%

Based on the indicated economic parameters and criteria the key financial indicators for the proposed Project Activity were calculated:

KEY FINANCIAL INDICATORS	
TOTAL NPV @ 16% (US$)	-21,494,654
IRR (%)	2,44%

The economic analysis in the financial model shows an IRR of 2,44% for the Project Activity. This level of return lies clearly under the determined project benchmark rate of 18%. The project benchmark was estimated based on the standard parameters in the market provided by the Guidelines on the Assessment of Investment Analysis v.5. The Project Activity is solely funded by PETROAMAZONAS EP without external commercial debt and at no cost of capital. PETROAMAZONAS EP has no long-term debt which is reflected in the determination of the Project Activity's debt/equity structure. The lack of any debt funding (gearing) in the project confines the benchmark determination to that of cost of equity. The expected return on equity has been determined using the value provided in Annex A of the Guidelines for "Group 2" (Sectoral scope 10: Fugitive Emissions from Fuels) projects in Ecuador. Per guidance from the "Guidelines on the assessment of Investment Analysis, v.5" the value, 18%, provided in paragraph 8 in the Appendix of the Guidelines, is used as a simple default company internal benchmark. Note that this value is very conservative as it is in real terms whereas the economic analysis has been performed in nominal terms i.e. including inflation.

I. Sensitivity Analysis:

This section summarizes the sensitivity analysis for testing the above conclusion regarding the economic attractiveness of the Project Activity. Key parameters are modified to test under what assumptions the project would meet the benchmark.

CAPEX:

Given the fact that the Project Activity is integrated into existing facilities, the risk of cost overrun is high. A situation where capital costs would decrease seems highly unlikely. According to the sensitivity analysis the capital costs would need to decrease by 39.2% in order for the project to meet the benchmark. This is not possible, given the fact that as of the end of 2010 66.24% of the total planned budget was already spent; please refer to the "OPTIMIZATION OF POWER GENERATION PROJECT.XLS ", the tab "CURVA PROG OGE". Therefore, only 33.76% of the total planned budget is left to cover outstanding work while the project could hit the benchmark if the actual cost would be 39.2% lower than the initially planned. Moreover, inflation takes place in Ecuador and it is expected that the CAPEX will increase, please refer to:

http://www.indexmundi.com/ecuador/inflation_rate_%28consumer_prices%29.html (Ecuador Inflation rate (consumer prices) - Economy.pdf).

PRODUCTION GAS PROFILE:

An increase in Project returns could also be triggered by an increase in gas volumes. However, this is technically unlikely as the amount of gas that can be utilized is capped by the total amount of gas-based generation capacity installed under the Project Activity. A hypothetical increase in gas volumes would only benefit the project after 2013 once projected gas volumes start to diminish. The impact on the Project's profitability is minimal. A gas volume increase beyond 121% does not yield any additional returns as the limitation of the available capacity caps the benefit of increases in gas volume. The equity IRR of the project does not increase beyond 7,48% regardless of how much gas volumes would increase. Hence, we can conclude that an increase in gas volumes does not materially affect the outcome of the additionality analysis.

PRICE OF DIESEL:

As long as the Government of Ecuador (GOE) maintains its current fiscal subsidies to support a domestic diesel price of 0,901 $/gal this variable will have no impact on the IRR of the Project. The subsidized price has remained at their current levels for the last years period. Overall, it is very unlikely that diesel subsidies will be eliminated in the short term in Ecuador because in the past, policies related to passing on the real energy cost to the end users went hand in hand with a high political cost. The price of diesel would have to increase by 67.6% in order for the Project to meet the benchmark. This is highly unlikely. Hence, we can conclude that any reasonable increase in diesel prices does not materially affect the outcome of the additionality analysis.

PRICE OF OIL

At the start of Step 3 above, it was determined that the cost of crude oil used for power generation by PETROAMAZONAS EP´s to maintain its crude oil production has no financial impact on its operations. Under its by-laws it only receives a consideration which is in function of its production costs, and not of any national, regional or international market price for the crude oil production including any economical benefit for the crude oil saved as a result of the Project Activity. The consideration / price obtained by PETROAMAZONAS EP for the transfer of the entire oil extracted by PETROAMAZONAS EP has indeed been historically fixed, by way of its operating licence, in function of its production costs. Any and all reduction of on-site

consumption therefore would not affect the production costs. For purposes of conservativeness an additional sensitivity analysis is conducted to gauge the impact on the IRR when pricing crude oil savings as a result of the Project Activity. In this context the price used is the cost per barrel of crude oil reported by PETROAMAZONAS EP to the corresponding government entities. This price was $US7,67 in 2008 which corresponds to data that was available when the investment decision was made in 2009 and which corresponds to the funding of its activities and is the consideration for the transfer of the extracted oil to the State of Ecuador. The average annual production cost is therefore akin to a transfer price as it is the average price which the Ecuadorian government values when assigning the operating budget to PETROAMAZONAS EP. This given the regulated consideration received by PETROAMAZONAS EP for the production of crude oil it transfers to the Government of Ecuador, this is the most relevant company-specific price per barrel of crude oil to be used in the sensitivity analysis, given the fact that PETROAMAZONAS EP has no access nor exposure to market pricing.

Applying the company specific transfer price as the crude oil price to the reduced on-site consumption into the sensitivity analysis increases the project IRR to 7,56%; a level still clearly below the benchmark. From this hypothetical level, the crude oil price would then have to increase further by 208% to reach the benchmark level. This represents a historically unprecedented transfer price level which is two times higher than the highest annual production cost over the last 5 years. Such a drastic increase in crude oil production cost is not a realistic assumption.

To further strengthen the findings of the investment analysis it needs to be noted that the official reported production cost of PETROAMAZONAS EP (the one used as the implied price of crude oil for the sensitivity analysis), does not include the value of crude oil consumed for power generation to sustain crude oil production. This cost of crude oil is not even a line item in the official reporting of PETROAMAZONAS EPs' operational costs whereby this is validated by the Deloitte auditing report.

ADDING ASOCIATED GAS GENERATION CAPACITY

The total installed gas-based power generation capacity is driven by the uncertain nature of gas availability and volume. In order to account for this fact, and ensure the conclusions from the additionality test remain valid, the sensitivity of the equity IRR of the Project Activity to increased capacity and energy production using associated gas has been tested. Under a scenario in which it is assumed that there is no limitation on associated gas installed capacity, and assuming that there is no incremental cost involved in increasing the installed capacity to match available associated gas during the corresponding years, the IRR would only increase to 9.71% which is still well below the benchmark. Assuming that there is no limitation of installed capacity the IRR increase is still is capped by the availability of associated gas whereby this restricts the total potential associated gas based-energy production. Accordingly, the sensitivity analysis shows that, even when increasing the gas based – energy production by 240% at the start of the project, the IRR doesn't change. We can therefore conclude that a potential increase in gas-based generation capacity does not impact the outcome of the additionality analysis because the project returns will remain well under the benchmark even under the most optimistic scenario.

The table below summarized the sensitivity analysis.

SENSITIVITY ANALYSIS	
PARAMETER	**Required change for IRR to reach benchmark**
CAPEX	-39.2%
PRODUCTION GAS PROFILE	+121% (IRR capped at 7.48%)
PRICE OF DIESEL	+67.6%
PRICE OF CRUDE OIL	+208%
ADDITIONAL GAS-BASED GENERATION CAPACITY	+240% (IRR capped at 9.71%)

On the account of the analysis above we can conclude that the Project Activity IRR would meet the benchmark only through highly unrealistic changes in key operating parameters.

J. Conclusions from the analysis of Economic Attractiveness

- The equity IRR of 2.44% is well below the derived company internal benchmark for the Project Activity.
- Based on the sensitivity analysis, the proposed CDM Project Activity is unlikely to be financially/economically attractive and evaluation can proceed to Step 4 (Common Practice Analysis).

K. Additional confirmation of additionality by means of investment comparison analysis at country level

This Project Activity has been rejected previously on the grounds of (supposedly) lacking input values to the investment analysis. To address the expectations of a broader investment analysis (at country level), and to further substantiate the additionality of the Project, a separate additionality confirmation is provided below. In response to input received by the Project Participants during the previous validation process, the analysis expands the Project Boundary beyond the physical boundary of the Project Activity as defined in this PDD whereby this goes beyond the requirements of AM0009 v.05.0.1 and also includes an additional baseline alternative and project participants. Although this supplementary approach taken to prove the additionality of the Project (as well as the expansion to other participants beyond the project boundaries) does not fall within the AM0009 V.05.0.1, it is performed to meet the request for an additionality analysis in relation to the economical value of saved crude oil (Section I above) to the level of international market prices.

In order to account for international oil market prices, the additionality analysis must be lifted one step to the national level i.e. hypothetically including the State of Ecuador as project participant since the State receives the entire oil extraction by PETROAMAZONAS EP as a regulated consideration. Importantly, this allows for increased oil revenues from the Project Activity to be appropriately compared with potential revenues from other “business as usual” oil projects (incl. alternative oil enhancement projects) at Government level,

To assure a level playing field the market-based crude oil price would have to be assumed for both scenarios being: i) Project Activity and ii) “Business as Usual”, i.e. traditional oil exploration activities.

Using an 11-year[8] NPV calculation as an investment comparison analysis the additionality of the Project becomes even more apparent. Investing the Project Activity budget in additional crude oil production instead of energy efficiency, the government could drill an additional 15 new oil wells and consequently increase gross daily oil production by an average of a little over 4000 barrels per day over 11 years. On the other hand, by means of the Project Activity the average net crude oil production only increases by an average of 642 BBl/day. The analysis in Table 1 below clearly illustrates that the Government of Ecuador would be far better off in terms of net income investing the money in current oil exploration / production programs rather than associated gas utilization and energy efficiency. By allocating US$ 81 million in associated gas utilization and energy efficiency, i.e. the Project Activity, the Government of Ecuador forgoes income of nearly US$ 700 million, on a NPV basis, over the period of the analysis. This analysis is based on highly conservative assumptions wherein a steeper crude oil production decline factor was used than the decline factor assumed for associated gas energy production despite the fact that, the decline rate of associated gas is tied to the decline factor of crude oil production volume.

Item	**CDM Project Activity Scenario**	**Crude Oil Enhancement Scenario**
Investment	81,000,000	81,000,000
Average Net Crude Oil savings due to Project Activity over a 11 year period (bbl/day)	642	
Total Net Crude Oil savings due to Project Activity (bbl/ 11yrs)	2,342,599	
Average Cost per drilled well (US$)		5,335,832
Total number of wells that could have been drilled with Project Activity funds		15
Average production per new well in PETROAMAZONAS over a 11 year period (bbl/day)		274
Average potential crude oil production enhancement over a 11 year period (bbl/day)		4,108
Total potential crude oil production enhancement over a 11 year period (bbl)		16,492,162
Diesel savings (gal/ 11 years)	87,982,248	
International price of diesel ($/gal)	3,20	
International price of crude oil ($/bbl), 2008 average	99,92	99,92
Additional income crude oil sale ($/year), 11-yr average	23,407,301	149,809,160
Savings diesel importation ($/year), 11-yr average	28,159,791	
Decline factor used for the Country Level Comparative Analysis (over 11 year period)	91.03%	74.06%
NPV of 11-year income/savings from project activity at	232,937,769	

[8] The analysis includes 10-years full years of operation for the CDM Project Activity Scenario. Due to much quicker implementation the Crude Oil Enhancement Scenario starts 1 year earlier. Hence the lifetime of the analysis is 11 years.

country level ($)		916,391,702
Total lost income country due to CDM project activity ($)	(683,453,933)	

Table No. 3: Country-Level Investment Comparison Analysis Project Activity[9]

As a direct result of its operating licence, PETROAMAZONAS EP has no access to the market price of crude oil. The valuation of the avoided on-site consumption at a market price could only occur at the State level. The investment comparison analysis in Section K above clearly shows the project's additionality also under this approach.

STEP 4: COMMON PRACTICE ANALYSIS

All power generators, both those that are connected to the national grid as well as auto generators in island mode operation, have to register their installed capacity and project specifics such as capacity per unit, installed capacity per site and fuel type and consumption at the regulatory entity CONELEC. In the year 2008 the only other project registered as optimizing associated gas for power generation is that of REPSOL Block 16 (Source: CONELEC, Boletín Estadístico 2008, Page 153).

As per Tool for demonstration and assessment of additionality Version 06.0.0, the following steps need to be taken for the Common Practice Analysis:

Paragraph 47: For measures that are listed in paragraph 6 (Project Activity falls in the category (b))

Step 1: Calculate applicable output range as +/- 50% of the design out or capacity of the proposed Project Activity:

Common Practice Analysis				
PETROAMAZONAS EP CDM Project				
Plant	**Nominal Capacity**	**Technology**	**Range**	
	MW		**50%**	**-50%**
CDM Proposed Project	62.65	MCI	93.98	31.33

Step 2:

Other Plants in applicable geographical area:	**MW**			
Total Repsol YPF	**56.52**	**MCI**	**within the range**	

$N_{all} = 1$

Step 3:

[9] Please see spreadsheet "7.Country level analysis" in the Investment Analysis 2012 06 18 (2) for full details on the investment comparison analysis.

The technology applied by the Project Activity for ILYP is the same technology as the one used by REPSOL YPF. However, the technology installed under the Project Activity for EDEN YUTURI is different in that it combines flexible use of crude oil and associated gas rather than providing an alternative to diesel-based power generation. In this case there is one associated gas power that partially applies similar generation technology within the output range of the Project Activity.

Step: 4

However, although from a nominal capacity perspective and (partial) technology perspective the REPSOL YPF meets the criteria of "technology similar to the technology in the project activity" it has to be recognized that the technological scope and conditions of the Project Activity is completely different to the REPSOL YPF case.

- The REPSOL YPF associated gas power generation technologies/facilities were built as "Greenfield" projects (from "day one"), i.e. at the same time of constructing the oil field infrastructure, and <u>not</u> as "Brownfield" projects as is the case of the Project Activity. This means that, the "switch of technology" criteria, as indicated in paragraph 6 in the Tool for demonstration and assessment of additionality Version 06.0.0, does <u>not</u> apply for the REPSOL YPF project because the technology implemented did not replace anything as it was a Greenfield project. It also means that the technologies are dissimilar through application in addition to being partially dissimilar by function. Therefore,

$N_{diff} = 1$

Step 5:

Factor F = 1 – (N_{diff}/N_{all}) => F= 1 – (1/1) = 0.
N_{all} - $N_{diff\,-}$ = 0

As the Factor F is not greater than 0.2 and N_{diff}/N_{all} is not greater than 3 the project cannot be deemed common practice in Ecuador.

Block 31 is a new field but no new power generation facilities will be built in this Block, because, power will be generated by the brownfield project in EDEN YUTURI whereby the power will be transported with an underground transmission line (the underground transmission line is not part of the Project Activity). The common practice analysis applicable to Block 31 is thus the same as that of Block 15.

Hypothetically, even if the two projects were assumed similar (N_{diff} = 0) the analysis still concludes that the Project Activity is NOT "common practice":

Step 4 (hypothetical):

$N_{diff} = 0$

Step 5 (hypothetical):

Factor F = 1-(N_{diff}/N_{all}) => F= 1 – (0/1) = 1.
N_{all} - N_{diff} - = 1

As the Factor N_{diff}/N_{all} is not greater than 3 the project cannot be deemed common practice in Ecuador.

SUB STEP 4B is not required per guidance in paragraph 43.

SUMMARY OF ASSESSMENT AND DEMONSTRATION OF ADDITIONALITY

INDENTIFIED PLAUSIBLE SCENARIO (STEP 1)	LEGAL ASPECTS (STEP 2)	ECONOMIC ATTRACTIVENESS (STEP 3)	COMMON PRACTICE (STEP 4)
Alternative 1 (combination of G2 – P4): Continuation of the operation of the existing oil gas infrastructure without processing of any recovered gas that implies continuation of the current practice – gas flaring).	Not prohibited by law	• Business as usual. • No additional risk involved. • No additional funds required. • NPV 0	Common practice: Flaring is widespread for oil fields in Ecuador.
Alternative 2 (combination of G8 – P1): Construction of a processing plant for the purpose of processing the recovered gas which is consumed on-site to meet energy demands without being registered as a CDM project activity.	Not prohibited by law. Although, associated gas recovery is recommended; this is not mandatory.	• Capital intensive. • Additional risks. • Lacks Economic Incentive due to: i) Crude oil for power generation is free of charge and ii) price of diesel is subsidized.	Optimizing flare gas in existing oil production facilities is NOT common practice in Ecuador. Factor F = 0 and N_{all}-N_{diff} = 0

The above is supported by the facts that:

- Baseline Alternative 2 does not represent the financially most attractive course of action
- The Project Activity is not required to meet existing and future power requirements to maintain crude oil production operations and or meet future power demand since PETROAMAZONAS EP, prior to the Project Activity, purchased required crude oil and diesel power generation facilities to meet the power demand of the Block 15 and Block 31;
- The financial return of the Project Activity does not meet the identified financial benchmark
- Gas flaring in the oil industry in Ecuador is common practice

Hence, the project activity is additional.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

Baseline emissions

The baseline emissions are according to AM0009 version 05.0.1 and related to those emissions that would be generated in the absence of the Project Activity therefore generating power with other fossil fuels. Project activities under this methodology reduce emissions by recovering associated gas and utilizing this recovered gas in a productive manner. The utilization of the recovered gas displaces the use of other fossil fuel sources.

The proposed Project Activity comprises the utilization of the recovered gas to displace the use of diesel and crude oil as sources to generate power at PETROAMAZONAS EP's facilities. However, the AM0009 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 CO2 emissions.

Hence, baseline emissions are calculated as follows:

$$BE_y = V_{F,y} \cdot NCV_{RG,F,y} \cdot EF_{CO2,Methane}$$

Where:

BE_y	= Baseline emissions in year y, (tCO2e)
$V_{F,y}$	= Volume of total recovered gas measured at point F in Figure No.7, after pre-processing and before the part of the recovered gas may be used on-site, in year y, (Nm³)
$NCV_{RG,F,y}$	= Average net calorific value of recovered gas at point F in Figure No.7 in year y, (TJ/Nm3)
$EF_{CO2,methane}$	= CO2 emission factor for methane (tCO2/TJ)

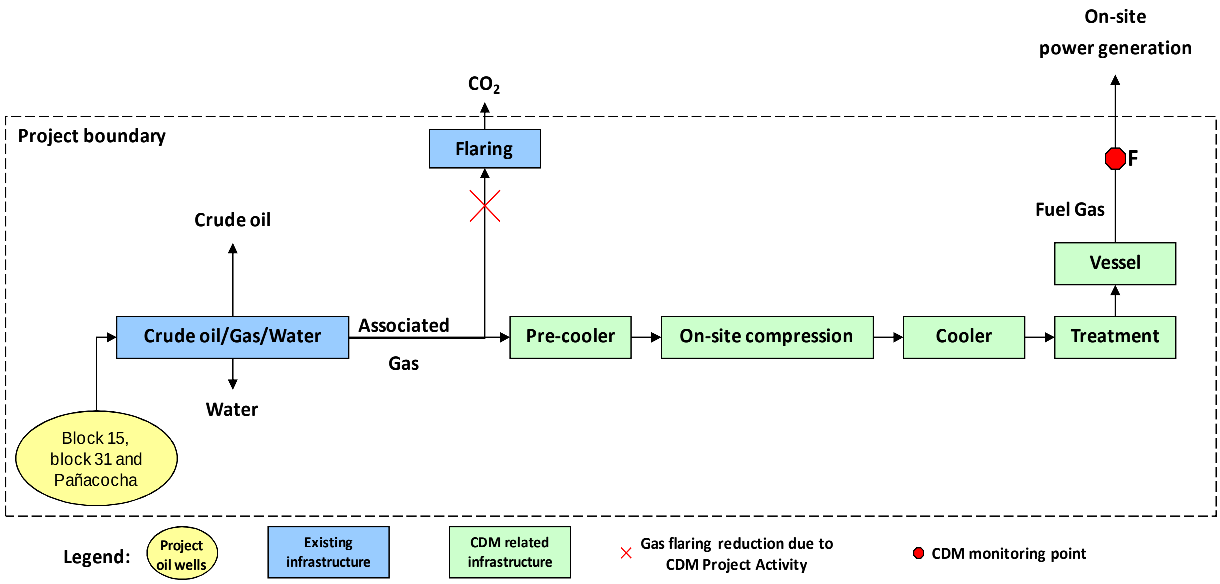


Figure No. 3: Schematic illustration of the project activity

Project emissions

The following sources of project emissions are accounted for in AM0009 version 05.0.1:

1. 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 pipeline (point F in Figure 2 in AM0009);
2. CO_2 emissions due to the use of electricity for the recovery, pre-treatment, transportation, and, if applicable, compression of the recovered gas up to the point of delivery into an existing gas pipeline (point F in Figure 2 in AM0009).

The project emissions[10] to be accounted for are the CO_2 emissions related to the electricity generated and consumed by the gas handling (compression and treatment) systems up to Point "F" as indicated in Figure 3.

Project emissions are calculated as follows:

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

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, and, compression of the recovered gas up to the point F in Figure 3 in year y, (tCO2e)

$PE_{CO2,elec,y}$ = CO_2 emissions due to the use of electricity for recovery, pre-treatment, and, compression of the recovered gas up to the point F in Figure 3 in year y, (tCO_2e)

No other fossil fuel is used for powering the auxiliary systems related to the Project Activity, as all auxiliary equipment is supplied with electric power generated with associated gas. Project emissions therefore are limited to additional electric power consumption required for auxiliary equipment that are a part of the Project Activity (principally gas handling equipment) which nevertheless, and indicated previously, will be generated with associated gas.

Hence,

$$PEy = PE_{CO2,elec,y} = PE_{EC,y}$$

And (as per the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption" (Version 01)):

$$PE_{EC,y} = \sum_j EC_{PJ,j,y} \times EF_{EL,j,y} \times (1 + TDL_{j,y})$$

Where:

$P_{CO2,elec,y}$	=	Project emissions from electricity consumption in year y (tCO_2/yr)
$EC_{PJ,j,y}$	=	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 (tCO_2/MWh)

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

$TDL_{j,y}$	=	Average technical transmission and distribution losses for providing electricity to project auxiliary gas handling equipment j in year y
j	=	Sources of electricity consumption in the project

As per the “Tool to calculate baseline, project and/or leakage emissions from electricity consumption” (Version 01), the project falls under scenario B (“Electricity consumption from (an) off-grid fossil fuel fired captive power plant(s)”). TDL is assumed as zero.

Leakage

Leakage emission is calculated as follows:

$$LE_y = LE_{FC,y} + LE_{EC,y}$$

Where:

LE_y	=	Leakage emissions in year *y* (tCO_2e)
$LE_{FC,y}$	=	Leakage emissions due to fossil fuel consumption after point F in Figure 3 in year *y* (tCO_2e)
$LE_{EC,y}$	=	Leakage emissions due to electricity consumption after point F in Figure 3 in year *y* (tCO_2e)

Leakage emissions due to fossil fuel consumption

Because all associated gas is consumed on site, within the project boundary, the Project Activity does not cause any leakage due to fossil fuel consumption outside the project boundary. Leakage emissions due to fossil fuel consumption are zero.

Leakage emissions due to electricity consumption

Because all associated gas is consumed on site, within the project boundary, the Project Activity does not cause any leakage due to fossil fuel consumption outside the project boundary. Leakage emissions due to fossil fuel consumption are zero.

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

Data / Parameter:	**$EF_{CO2, Methane}$**
Data unit:	tCO_2/TJ
Description:	CO_2 emission factor for methane
Source of data used:	Calculated in line with procedures and data presented in ISO 6976:

Unit	**Value**	**Source**
Carbon Content of Methane	12,011 kg/kmol	ISO 6976: Table 1
CO_2 Emission Factor for Methane	44.01 kg/kmol	ISO 6976: Table 1
NCV of Methane (at 25° C)	802.60 kJ/mol	ISO 6976: Table 3

Value applied:	54.834 tCO_2/TJ
Justification of the choice of data or description of measurement methods and procedures actually applied :	Default value suggested by the methodology applied.
Any comment:	---

Data / Parameter:	$\mathbf{EF_{EL,j,y}}$
Data unit:	tCO_2/MWh
Description:	Emission factor for electricity generation for source j in year y
Source of data used:	Methodological tool “Tool to calculate baseline, project and/or leakage emissions from electricity consumption” (Version 01), page 8, Option B2.
Value applied:	1.3
Justification of the choice of data or description of measurement methods and procedures actually applied :	For the purpose of estimation only the most conservative value is applied following tool recommendations.
Any comment:	---

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

Baseline emissions

$$BE_y = V_{F,y} \cdot NCV_{RG,F,y} \cdot EF_{CO2,Methane}$$

Where:

BE_y	= Baseline emissions during the period y, (tCO2e)
$V_{F,y}$	= Volume of total recovered gas measured at points F in Annex 5, after pre-processing and before the part of the recovered gas may be used on-site, during the period y, (Nm^3)
$NCV_{RG, F, y}$	= Net calorific value of recovered gas measured at points F in Annex 5 during the period y, (TJ/Nm3)
$EF_{CO2, methane}$	= CO2 emission factor for methane (tCO2/TJ)

Project emissions

$PEy=PE_{CO2,elec,y} = PE_{EC,y}$

And (as per the “Tool to calculate baseline, project and/or leakage emissions from electricity consumption” (Version 01)):

$$PE_{EC,y} = \sum_j EC_{PJ,j,y} \times EF_{EL,j,y} \times (1 + TDL_{j,y})$$

For the purpose of estimation of project emissions the quantity of electricity consumed ($EC_{PJ,j,y}$) by the auxiliary gas handling equipment (refinery/ies) is measured as follows: representative loads (Gas Compressor) shall be measured by means of Power/Energy/Quality meters installed at the Variable Speed Drivers. Smaller consumers / auxiliary loads do not have direct meter installed whereby the consumption has been assumed as the maximum load during operation conditions. See also Table No. 2.

The emission factor for electricity ($EF_{EL,j,y}$) is assumed as per the tool recommendation as 1.3 tCO_2/MWh.

Leakage

Leakage emission is calculated as follows:

$$LE_y = LE_{FC,y} + LE_{EC,y}$$

Where:

LE_y	=	Leakage emissions in year *y* (tCO_2e)
$LE_{FC,y}$	=	Leakage emissions due to fossil fuel consumption after point F in Figure 4 in year *y* (tCO_2e)
$LE_{EC,y}$	=	Leakage emissions due to electricity consumption after point F in Figure 4 in year *y* (tCO_2e)

Leakage emissions due to fossil fuel consumption

Because all associated gas is consumed on site, within the project boundary, the Project Activity does not cause any leakage due to fossil fuel consumption outside the project boundary. Leakage emissions due to fossil fuel consumption are zero.

Leakage emissions due to electricity consumption

Because all associated gas is consumed on site, within the project boundary, the Project Activity does not cause any leakage due to fossil fuel consumption outside the project boundary. Leakage emissions due to fossil fuel consumption are zero.

Emission reductions

Emission reductions are calculated as follows:

$$ER_y = BE_y - PE_y - LE_y$$

Where:

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

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

Year	Estimation of project activity emissions (tonnes of CO2e)	Estimation of baseline emissions (tonnes of CO2e)	Estimation of leakage (tonnes of CO2e)	Estimation of overall emission reductions (tonnes of CO2e)
From 2013-01-01 to 2013-12-31	30,825	219,035	–	188,209
From 2014-01-01 to 2014-12-31	25,270	179,582	–	154,312
From 2015-01-01 to 2015-12-31	20,146	143,279	–	123,133
From 2016-01-01 to 2016-12-31	16,577	117,907	–	101,330
From 2017-01-01 to 2017-12-31	14,340	101,886	–	87,546
From 2018-01-01 to 2018-12-31	11,601	82,466	–	70,864
From 2019-01-01 to 2019-12-31	10,735	76,120	–	65,385
From 2020-01-01 to 2020-12-31	8,754	62,091	–	53,337
From 2021-01-01 to 2021-12-31	7,218	51,195	–	43,977
From 2022-01-01 to 2022-12-31	5,736	40,712	–	34,977
Total (tonnes of CO_{2e})	**151,202**	**1,074,273**	**–**	**923,071**

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

B.7.1 Data and parameters monitored:

Data / Parameter:	**$V_{F,y}$**
Data unit:	Reported as standard (Normal) m^3 (Nm3) at 15 °C and 1.01325 bar (international gas reference conditions).
Description:	Volume of total recovered gas measured at point F in Figure No. 3, after pre-processing and before the part of the recovered gas may be used on-site, in year y.
Source of data to be used:	1. Mass Flow Measurement: Coriolis Flow Meter. 2. Gas composition: Gas Chromatography. 3. Volumetric Flow Calculation: Flow Computer.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	See values applied in the spreadsheet attached to this PDD.
Description of	In order to measure mass flow continuously, a Coriolis Flow Meter will be

measurement methods and procedures to be applied:	installed that includes the following accessories: (i) Coriolis Flow Sensor, (ii) Coriolis Flow Transmitter. The On-Line Gas Chromatograph sampling periodically following the processing and analysis time required by the equipment and the number of sampling points. It will provide the gas composition at Normal conditions. A Flow Computer will calculate the required volumetric flow $V_{F,y}$ (Nm^3) at Normal conditions using the mass flow data and the gas composition measured by the On-Line Gas Chromatograph.. The On-Line Gas Chromatograph is complex and "state of the art" equipment whereby it has the lowest availability factor of the three components used to measure the volume of gas. For this reason, if the On-line Gas Chromatograph was unavailable, the Flow Computer will be configured to calculate using the last valid gas composition input recorded by the chromatograph. If this will becomes unavailable for more than a month, a gas composition sampling (on a monthly basis) will be carried out to set the analyzed gas composition at laboratory. Results from this analysis will be used as input for the flow computer calculations. The volumetric flow data will be recorded and stored automatically and continuously, firstly, at the flow computer and, secondly, as back up in the named "Historian Server" of the electrical SCADA system. Monitoring Frequency: • Mass Flow Meter: Continuously • Gas Composition: Automatically, on a daily basis, when on-line chromatograph is available. Manually, monthly, if the on-line chromatograph was unavailable. • Volumetric Flow (Volume of total recovered gas) Calculation: Continuously, calculated with the information provided by the Mass Flow Meter and Gas Composition.
QA/QC procedures to be applied:	Instrumentation will be calibrated in line with industry standards and relevant regulations. Maintenance will be done in accordance with the operational manual of the corresponding Original Equipment Manufacturer.
Any comment:	---

Data / Parameter:	**$NCV_{RG,F,y}$**
Data unit:	TJ/Nm3
Description:	Average net calorific value of recovered gas measured at point F in Figure 3 in year y
Source of data to be used:	Gas composition: Gas Chromatography Net Calorific Value Calculation: Flow Computer
Value of data applied for the purpose of calculating expected emission reductions in section B.5	See values applied in the spreadsheet attached to this PDD.
Description of measurement methods	The On-Line Gas Chromatograph sampling periodically following the processing and analysis time required by the equipment and the number of

and procedures to be applied:	sampling points. It will provide the gas composition as input to the flow computer that calculates the Net Calorific Value. As explained above, if the On-Line Gas Chromatograph was unavailable to sample, gas will be analyzed by an accredited laboratory following the measurement procedures established at AM0009 V. 05.0.1. Results from this analysis will be used as input for the flow computer calculations. The Net Calorific Value data will be recorded and stored automatically and continuously, firstly, at the flow computer and, secondly, as back up in the named "Historian Server" of the electrical SCADA system.. Monitoring Frequency: • Gas Composition: Automatically, on a daily basis, when the On-Line Gas Chromatograph is available. Manually, at least monthly, if the Chromatograph was unavailable. • Net Calorific Value: Continuously calculated with the information provided by Gas Composition.
QA/QC procedures to be applied:	Instrumentation will be calibrated in line with industry standards and relevant regulations following the QA/QC procedures established at AM0009 V. 05.0.1. Maintenance will be done in accordance with the operational manual of the corresponding Original Equipment Manufacturer.
Any comment:	Given the fact that calculations will be done on-line and continuously by the Flow Computer, the Baseline Emissions Calculation is the result of the continuous product of the instant Net Calorific Value, the Volume of recovered Gas available at every time and the default value of CO2 emission factor for methane (54.834 tCO2/TJ). The result will be totalized at the end of the period (y).

Data / Parameter:	**$EC_{PJ,j,y}$**
Data unit:	MWh/yr
Description:	Quantity of Energy consumed by the project electricity consumption source (j) in year (y)
Source of data to be used:	Main loads (Gas Compressors) shall be measured by means of the Power/Energy/Quality meters installed into the Drivers (continuous measurement). For minor/small loads energy shall be calculated based on the Nominal Power Value shown on the Nameplate of each electric motor / load.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	See values applied in the spreadsheet attached to this PDD.
Description of measurement methods and procedures to be applied:	Representative loads (Gas Compressor) shall be measured by means of Power/Energy/Quality meters installed at the Drivers. Smaller consumers / auxiliary loads do not have direct meter installed whereby the consumption has been assumed as the maximum load during operation conditions. See also Table No. 2.
QA/QC procedures to	Power/Energy/Quality meters are delivered with corresponding factory

be applied:	calibration certificates whereby these are recalibrated on a yearly basis.
Any comment:	---

B.7.2. Description of the monitoring plan:

In order to ensure the successful implementation and operations of the CDM Project Activity, PETROAMAZONAS will setup a team to oversee the implementation of the Monitoring Plan. This includes making sure that proper monitoring equipment is specified and installed whereby this must go hand in hand with the corresponding operations, measurement, registration and maintenance procedures (together referred to as the Monitoring Plan). The CDM Monitoring Plan will be integrated into PETROAMAZONAS´ Operations & Maintenance Procedure.

The Monitoring Plan consists of six key elements to ensure that: i) Monitoring Plan complies with CDM Project Activity requirements, ii) relevant data is collected, iii) data is collected based on industry standards, iv) monitoring consistency during operations / measurement, v) proper operations and maintenance procedures and vi) assure that is it “user friendly” to both operators and a DOE.[11]:

A. Data collection task:

Data needs to be collected for monitoring the Project Activity whereby the collected data must comply with minimum requirements as laid out in Section B.7.1. For every relevant parameter: recording and filing instructions must be issued thereby making sure indicated parameter are recorded and registered accordingly (physical and digital).
Measuring points F are indicated in the Annex 5. These points will be supplied with flow meters and chromatographs as stated in the section B.7.1.

B. Equipment calibration task:

For each instrument used for the purposes of the CDM Monitoring Plan, a separate calibration procedure shall be defined. This includes definition of any relevant calibration standards, guidance from equipment supplier, and accuracy of equipment and means of calibration to ensure its compliance with the Monitoring Plan. All measurements shall be conducted with calibrated measurement equipment according to relevant industry standards.

C. Mechanism for data reconciliation:

Under the Monitoring Plan, PETROAMAZONAS EP shall also identify procedures, means and sources to verify / reconcile data obtained from the measurement devices/procedures. For example, fossil fuel quantity consumption needs to be crosschecked, reconciled or consolidated with multiple sources such as operators at power plants and the purchasing department in charge of procuring diesel for the power generation activity.
If a relative comparison between measuring devises will reveal abnormalities i.e. out-of range values a calibration will be triggered immediately.

[11] Clean Energy Finance Committee, Mitsubishi UFJ Securities, “GHG Emission Reduction Monitoring & Reporting Guideline: A Practical Guideline for the Implementation of the Monitoring Plan and the Reporting of GHG Emission Reduction”, Version E-1.0, December 2006.

D. Storing data:

According to the AM0009 – Version 05.0.1, all data collected under the Monitoring Plan must be stored electronically for at least 2 years after the date of the corresponding crediting period. In order to meet this obligation, PETROAMAZONAS EP shall establish the means of storing the data (with corresponding back-up system) to ensure that the data can be accessed when required.

E. Emission reductions calculation and reporting:

A calculation and reporting format must be pre-established whereby, by feeding in the corresponding “on-line” data (data collected on a continuous basis whereby operators can see and evaluate trends and historic data), accurate and relevant crediting information can be obtained. The previous not only reduces the margin of error (either operating, measurement or calculation errors) considerably but also allows the stakeholders to get direct consolidated information (“on-line”) required for the reporting and verification process. To support this activity PETROAMAZONAS EP is implementing an integrated SCADA (Supervisory Control and Data Acquisition) system.

PETROAMAZONAS will install all necessary meters and monitoring equipment and software to secure that all relevant data is collected, stored, processed and communicated accordingly. The calculation of emission reductions can be performed efficiently and accurately using spreadsheet applications.

F. Training program and procedure compliance:

Prior to implementing the Monitoring Plan, it is important to develop a training program and an Operations Manual for operators and Project Activity Supervisors. Employees at the sites of the Project Activity shall be trained and equipped to perform their activities in line with monitoring requirements to ensure that relevant and accurate emission reduction data collection and processing takes place.

The data will be “on-line” and stored at CPF´s and EPF´s SCADA system. Additionally the information will be stored at PETROAMAZONAS´ headquarters in Quito. Data will be stored in compliance with monitoring requirements.

G. Management structure for the implementation of the monitoring plan:

A CDM Project Manager will be responsible for structuring and overseeing all the data collection activities, measurements, calibration and reporting in line with the Monitoring Plan for the Project Activity. A specific work / reporting flow diagram will be developed indicating which parties need to be involved and to what degree for each activity. The figure below provides a preliminary graphical representation of the Management Structure for the implementation of the Monitoring Plan:

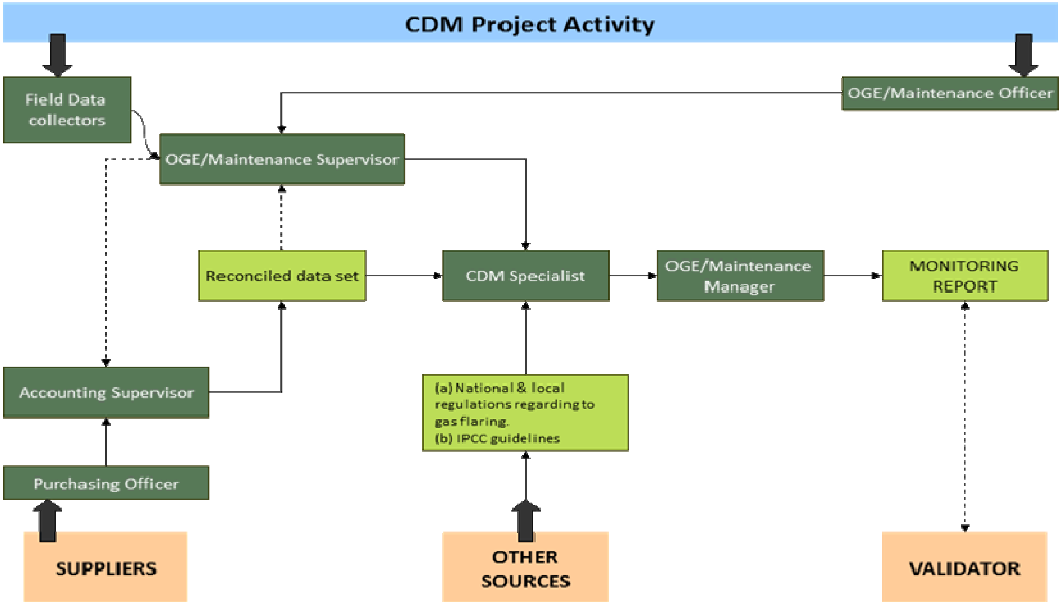


Figure No. 4: Schematic illustration of the management structure for the implementation of the monitoring plan

The CDM Supervisor is responsible for making sure that each party understands and abides by the procedures laid out in the Monitoring Plan. Additionally, after verifying that collected relevant data is accurate, this is processed accordingly to issue the Monitoring Report. Apart from monitoring and auditing internal activities and procedures to assure accurate reporting he must also monitor external factors, such as regulatory issues, that could have an impact on the CDM Project Activity and corresponding Monitoring Plan.

The OGE Project Director or Maintenance Manager will review the whole process before approving and formally issuing the corresponding Monitoring Report.

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):

This Baseline Study was completed on the 5th of October 2009 using methodology AM0009 Version 05.0.1 was used. The Baseline Study was prepared “in-house” by Berend van den Berg (Project Director) and David Neira (CDM Specialist).

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:

12.02.2009

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

10 years

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

C.2.1. Renewable crediting period:

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

Not applicable

C.2.1.2. Length of the first crediting period:

Not applicable

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

01.01.2013

C.2.2.2. Length:

10 years

SECTION D. Environmental impacts

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

The Project Activity is regulated under the following environmental legal framework:

- “Law on Environmental Management”
- “Law on Prevention and Environmental Contamination Control”
- “Environmental Rules and Regulations for Electrical Activities”
- “Unified text on Secondary Environmental Legislation, particularly the book VI and its respective annexes / specifications applicable to the electricity sector”.

The Power Generation Systems fall under the Environmental License Nº 044, 042 y 075, respectively. Additionally, during the year 2008 the Environmental License N° 014 was issued for the New Power Plant running on crude oil in EY whereby this process required new Environmental Impact Assessment (EIA) that was concluded and published on the 30th of May 2008 by Communication DE-08-1070 issued by the “National Electricity Council” (CONELEC).

With the objective to ensure compliance of PETROAMAZONAS EPs’ environmental management procedures with the requirements laid out in the “Environmental Rules and Regulations for Electrical Activities” (Artículo 13 y Artículo 37, Literal b), PETROAMAZONAS EP is subject to periodical Environmental Audits (referred to as “Auditorías Ambientales Internas (AAI)”) by the Ministry of Environment. In line with this requirement, an audit was done in March 2009 for the environmental management procedures related to power generation activities in Block 15 in 2008.

The environmental audit focused on operational conditions of the auto-generation system and the surrounding areas by measuring and analyzing social-environment impacts, condition of power generation equipment and related infrastructure, and potential environmental impact. By means of site visits and corresponding monitoring, air quality, magnetic fields, noise level, etc. were measured and quantified. Further analysis was then undertaken to determine compliance of PETROAMAZONAS EP operations with applicable environmental norms for the electric sector.

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:

In line with the terms of reference issued by CONELEC for environmental auditing, the following parameters were monitored[12]:

- Discharge of effluents
- Solid Waste Management
- Emissions
- Air Quality

[12] ENTRIX “Internal environmental audit to current power generation systems at Indillana, Limoncocha and Yanaquincha and Eden Yuturi Field”, March 2009.

- Noise Level
- Electromagnetic fields
- Social aspects

During the environmental auditing process, 108 items were reviewed whereby 94.4% of the reviewed items were found to be in compliance, which demonstrates that in general PETROAMAZONAS EP has a very acceptable level of environmental management. Particularly concerning to health, safety, training, procedures, equipment and response capacity to emergencies PETROAMAZONAS EP scores above average.

- Air Emissions:

As result of the fieldwork, certain problem areas were detected concerning air emissions. The monitoring results show that of the 301 sources monitored in ILYP 18.60% exceed the established limits whereby in EY, of the 64 sources monitored, 31.25% exceed the limits. The Project Activity will play an important part in improving the air pollution from the Block 15 and Block 31. PETROAMAZONAS EP carries out scheduled and preventive maintenance according to the Operations Manuals of the OEMs.

- Noise Levels:

The noise level within the facility boundary limits comply with regulatory norms whereby the noise level to which the workers are exposed is not high. In general workers seldom enter the power generation engine hall (where most of the noise is concentrated) and in these cases only for short periods of time and with required personal safety equipment and ear protection.

However, with the regards to noise impact outside the facility boundaries it was determined that certain noise mitigation work is required. Part of the work consists in installing additional silencers in series with existing silencers and installing noise absorption walls to mitigate noise from the engines. Additionally, in ILYP most of the gas generating equipment will be installed in noise mitigation enclosures.

- Social Aspects:

The audit concludes that there is a good level of compliance in terms of social aspects. The report concludes that PETROAMAZONAS EP has complied with the terms and conditions laid out in community agreements in the areas of influence of the Block 15 and Block 31, and that no breaches of compliances have been registered. Nonetheless, the report recommends for PETROAMAZONAS EP to disclose more openly the content of the agreements in place to the local communities, thereby helping the communities to understand the scope and timelines of the agreements.

The recommendations laid out in the audit report are geared towards improving specific environmental management aspects such as air emissions and social aspects. The OGE Project should be considered as an important means to mitigate environmental impact such as air and noise emissions. Nevertheless, the recommended corrective actions outlined in the Environmental Audit, must be implemented within the indicated timelines with the clear objective to overcome the listed breaches in compliance.

As indicated above, the Project Activity will mitigate two key issues addressed in the Audit Report, namely:

- Air Quality: the air quality will improve significantly when optimizing flare gas for power generation, namely, not only will flaring be reduced to the minimum but using associated gas as a fuel for power generation, but, air emissions as such as lower when generating with gas then with liquid fuel.
- Noise Impact: Centralizing power generation through installation of new power distribution networks will reduce the number of power generation units.

SECTION E. Stakeholders' comments

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

With the objective to get corresponding feedback from national and local stakeholders regarding the Project Activity, PETROAMAZONAS EP established a campaign to disclose and communicate the scope and objectives of the Project Activity putting special emphasis on the potential to mitigate Climate Change. To raise the awareness of the Project Activity, its scope and objectives, and subsequently obtain feedback, PETROAMAZONAS EP used various instruments whereby the first tool was publishing the PIN on its website.

Local written media, such as corporate news magazine, industry- and environmental magazines and national newspapers, were also used to create awareness of the Project Activity.

Additionally various platforms were used to present the Project Activity on the National and International scene such as:

- Carbon Expo 2009 in Barcelona Spain.
- Latin American Carbon Forum 2009 in Panama City.
- Oil&Power Conference in Quito Ecuador in 2009.

Throughout the whole process the Project Activity has been presented to all the corresponding Government Entities such as the President of the Republic of Ecuador, the "Ministry of Non-Renewable Natural Resources", the "Ministry of the Environment", the "Ministry of Finance", the Ministry for Planning and Development", SENPLADES; PETROECUADOR, etc.

Finally, PETROAMAZONAS EP presented the Project Activity to various local stakeholders with the purpose of giving them a chance to voice their concerns and opinions. Two separate meetings were conducted at Limoncocha on 27/01/2010 and at Eden Yuturi on 28/01/2010 project sites. During these meetings it was agreed upon that frequent meetings should be held to keep the local stakeholder updated on the Project Activity. The local stakeholders in this case consisted of:

- Leaders of all Communities in the area of influence.
- Representatives of Indigenous associations.
- Local authorities.
- Other key figures such as teachers, doctors, etc.

E.2. Summary of the comments received:

In general the Project Activity was positively received by both local- and national stakeholders, largely due to the fact that they perceived that the Project Activity will provide a positive impact on global climate change.

On a national level the Project Activity has been recognized as a project of "National Interest" whereby periodic updates need to be given to the President of the Republic of Ecuador. Part of this exercise consist of updating information on the website of the SIGOB (System for Democratic Governance) http://www.sigob.gov.ec/metas/main/consulta/default.asp whereby most of the information is available to the public and certain specific information available only to authorized authorities.

The response from the local stakeholders was also positive since they perceive the flare as a threat to their health and, most of all, they are very positive about the noise mitigation plan that is an integral part of the Project Activity. An extensive presentation was given to the local Stakeholders whereby they were given the opportunity to also express their concerns and recommendations. Below we lay out the key issues pointed out by the Local Stakeholders:

- Local Stakeholders want to get an update on the Project Activity on a periodic basis.
- They would appreciate it if the Project Activity is also presented in the schools.
- To the local Stakeholders it is essential that, to the extent possible, local labor is used for the Project Activity.

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

The stakeholder dialogues served the purpose of creating a platform through which stakeholders can continue interacting with PETROAMAZONAS EP regarding their concerns and questions regarding the Project Activity. The Project Activity was looked upon positively by the stakeholders, and this motivates PETROAMAZONAS EP to put emphasis on the following issues:

- Use the Project Activity as a platform to engage with the local stakeholders on a continuous basis.
- Engage the company to evaluate the option of reserving a certain percentage of CDM- based income to finance local sustainable community projects.
- Affirm its commitment to transparency in its communications with the local stakeholders.
- PETROMAZONAS is committed, as it has always been, to using local labor where possible.

Participant lists, minutes of meeting, photographic reports, etc. from the stakeholder meetings were used to document the proceedings.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

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Annex 2

INFORMATION REGARDING PUBLIC FUNDING

Not applicable for this Proposed Project activity.

Annex 3

BASELINE INFORMATION

National Circumstances

Background

Although Ecuador is a crude oil exporter, national refining capacity of fossil fuels does not supply current demand. The general refining statistics show that out of 62.9 million barrels of derivatives produced by the refineries in 2006 consisted of 15.6% Fuel Oil #4, 19.2% Diesel #2, 18.1% Gasoline's, 3.4% LPG, 25.1% other, and 18.7% correspond to residues.

The produced diesel has a high sulfur content, which not only generates accelerated deterioration of the equipment but also results in a higher environmental impact. The LPG production is limited, which consequently forces Ecuador to import this fuel to meet internal demand. As LPG is sourced from open markets cost are elevated which prevents the build up of any material reserves to mitigate contingencies.

The internal supply does not meet the national demand for high-octane naphtha and diesel fuel and subsequently these fuels have to be imported at international prices. Given the imbalance between internal demand and refining capacity, the country had to purchase 25.9 million barrels of derivates in the year 2006 and only exported 13.6 million barrels (mainly HFO) with unfavorable price differential3.

The average cost of imports in the year 2007 was 83 $/bbl versus an export price of 55.8 $/bbl. This result has a direct negative impact on the derivative trade balance, which tilted this toward negative values. Fuel imports between the 2004 and 2006 totaled USD 4.255 million while exports of crude oil derivatives over the same period totaled USD 1.404 million leaving a deficit to PETROECUADOR of USD 2.851 millions, a trend that has continued and increased3.

As indicated in the "*Strategic policies to change the energy matrix, May 2008"*3 [and13], associated gas is a key energy source that has not been properly tapped in Ecuador. It is estimated that around 1.25 million cubic meters of associated gas have been flared due to a lack of pipelines, compression facilities, and gas treatment plants and, due to a general lack of funds and commitment.

[13] Former Ministry of Energy and Mines, "Energy Agenda 2007-2011: Towards a sustainable energy system", June 2007.

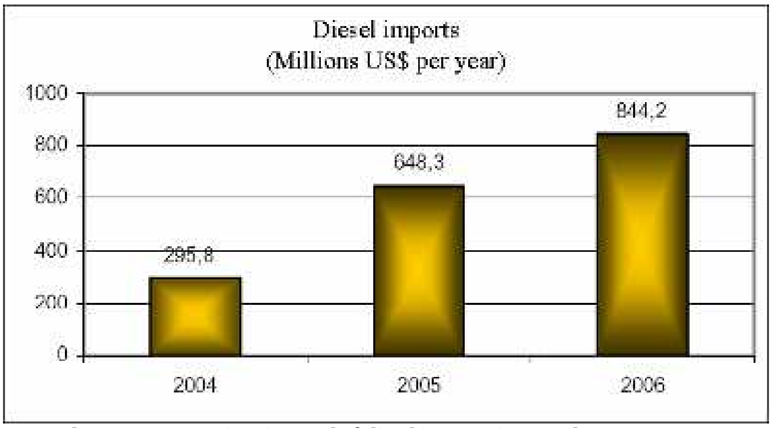


Chart No. A3.1: Historic trend of diesel imports in Ecuador (2004 -2006)
Source: Agenda Energética 2007 - 2011, 2007.

Utilization of associated gas in Ecuador is hindered by lack of incentives in The Hydrocarbon Law and a general shortage of funds, which leads to available funds being channeled to oil production projects.

Lack of funds and infrastructure to develop natural gas reserves or capture associated gas has contributed significantly in Ecuador's trade deficit. For example, natural gas could provide an alternative to imported LPG, which is mostly used for residential cooking and heating. In addition, increased natural gas production could supply more gas-fired power plants, replacing diesel, bunker C or crude oil generators[14]. Figure No. 6 presents the main sources of energy in Ecuador, illustrating that natural gas and/or associated gas accounts only for a small share of supply in the country's energy balances.

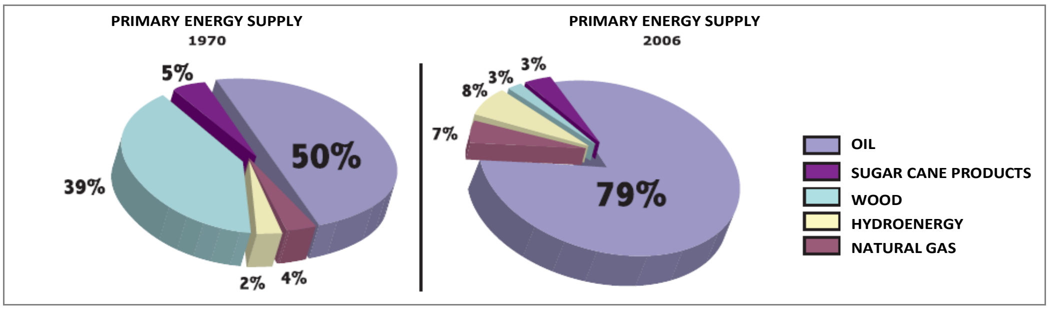


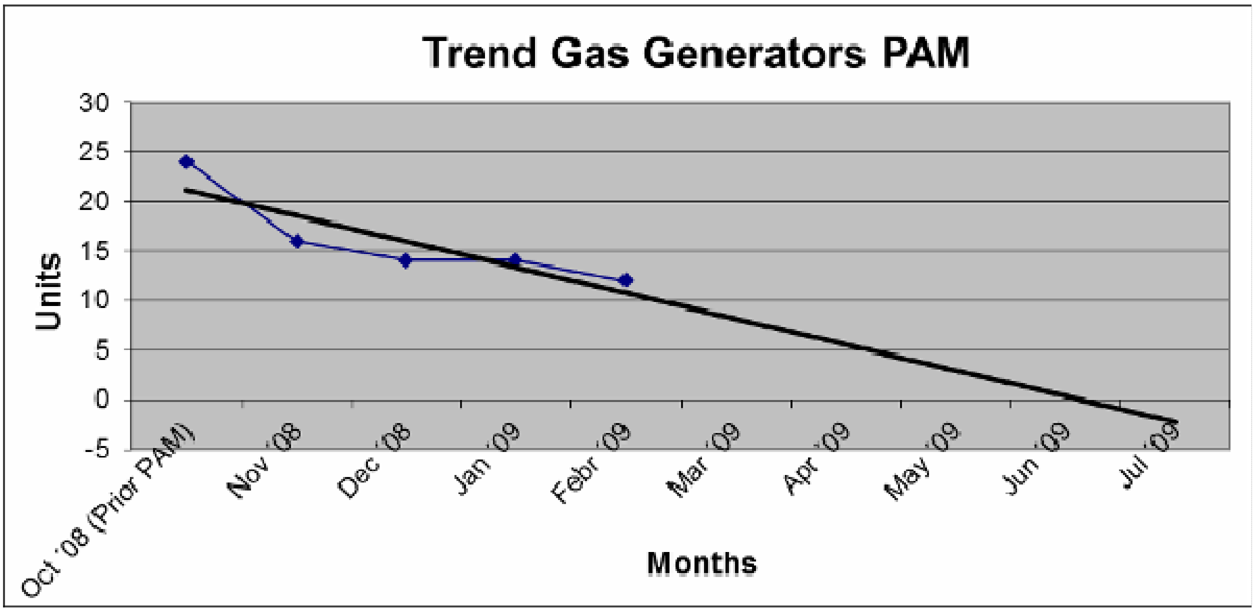
Fig. No. A3,1: The Ecuadorian Energy Matrix (1970, 2006)
Source: Ministry of Electricity and Renewable Energy, "Políticas y Estrategias para el Cambio de la Matriz Energética en el Ecuador", May 2008.

Local Petroamazonas Circumstances

As of October 2008 Petroamazonas operated 24 associated gas generators. In February 2009 only 12 (and only 11 early in March 2009) are left in operation i.e. within 5 months time 50% of generators were taken out from operation. A projection was made based on historical data which shows that most probably no associated gas power generators would be in operation in June 2009, please refer to "Trend Gas Generation Units PAM.xls" and the graph "Trend Gas Generators PAM" below. The reason for **such a** rapid decrease of power generation based on associated gas is very high unreliability and instability of the

[14] Energy Information Administration (Official Energy Statistics from the U. S. Government), "Country Brief Analysis: Ecuador Energy Data, Statistics and Analysis - Oil, Gas, Electricity, Coal", April 2008.

equipment. Critical deteriorating technical condition of equipment which used associate gas prior to the Project Activity is confirmed by several third-party organizations which inspected the project sites; please refer to “Certification ARCOLANDS Waukesha.pdf”, “Customer Copy- Work report Oxy _Wartsila document_.pdf”, “Scrapped Gas Generators before Project Activity.pdf”, “TECNA previous Project Activity ILYP 2008.pdf”. Finally, prior to the Project Activity Petroamazonas had clear intention to replace all gas power generators with more reliable and easier operated diesel and crude oil generators and invested nearly 50 million USD into such equipment; please refer to “POs Diesel Power Generation Units ILYP.pdf”, “POs Crude Oil Power Generation Units EPF.pdf”.



Annex 4

MONITORING INFORMATION

Not applicable

Annex 5

BACKGROUND INFORMATION ON PROJECT ACTIVITY

In order to avoid misunderstanding of information in this annex, please note that all equipment which is shown in charts below for the situation prior to the project would have been taken out at least by June 2009 in the absence of the project activity. In other words, in the baseline all associated gas would be flared and the equipment existed and utilized associated gas prior to the project implementation would have been scrapped and replaced with diesel and crude oil based equipment. Critical deteriorating technical condition of equipment which used associate gas prior to the Project Activity is confirmed by several third-party organizations which inspected the project sites; please refer to “Certification ARCOLANDS Waukesha.pdf”, “Customer Copy- Work report Oxy _Wartsila document_.pdf”, “Scrapped Gas Generators Before Project Activity.pdf”, “TECNA previous Project Activity ILYP 2008.pdf”. Moreover, according to the historical information (please refer to “PAM Timeline for the replacement of old generators”) for the period from October 2008 to February 2009 (so, just in 5 months) more than 50% of associated gas power generators were taken out from the operation due to technical faults. Finally, prior to the Project Activity Petroamazonas had clear intention to replace all gas power generators with more reliable and easier operated diesel and crude oil generators and invested nearly 50 million USD into such equipment; please refer to “POs Diesel Power Generation Units ILYP.pdf”, “POs Crude Oil Power Generation Units EPF.pdf”.

It should be noted that project implementation consists of three main phases. Where the first phase includes the recovery and adaptation of gas equipment existed prior to the Project Activity and that is possible and/or reasonable to overhaul; this equipment in the absence of the project would be scrapped at least by commissioning of the first unit of the Project Activity or even earlier. Phases 2 and 3 include installation of new equipment with the purpose of utilization of all associated gas available in the fields.

For more details on that please refer to the Section B of the PDD and to the table below.

STATUS POWER GENERATION WITH GAS PRIOR TO AND AS A RESULT OF PROJECT ACTIVITY

This table includes information about all gas based generators which are used in the project activity i.e. installed before the project and overhauled (kept running) due to the project and newly installed.

No.	Model	TAG	Location	Existing or new as of the project activity start date	Nominal Capacity (kW)	Capacity as of the project start date (kW)	Phase	Planned Operating Capacity after the project implementation (kW)	Observations
1	VHP 7100	MG 102	CPF	Existing	1 000	-	1	800	MG 102, MG 103 and MG 301-3 were purchased second hand by previous operator (OXY) whereby they found out that these engines originally were designed to run on diesel and had been coverted to gas engines. **These engines were NOT operational when the Project Activities started and were stationed 2 x Laguna and 1 x Jivino A (NOT operational).** Considerable investments were made on the part of PAM to get these engines operational (we have contract documents supporting the total amount of investment requiered to put these units into operations). The MG 101-9 was operating but only at 300 kW whereby it was at the point of coming to a halt and would be definitely scraped by June 2009.
2	VHP 7100	MG 103	CPF	Existing	1 000	-	1	800	
3	VHP 7100	MG 301-3	CPF	Existing	1 000	-	1	800	
4	VHP 7100	MG 101-9	CPF	Existing	1 000	300	1	800	
5	GE320	GE320 - GP 1	CPF	New	1 000	-	2	800	These have been contracted under the Project Activity whereby PETROAMAZONAS holds a purchase option.
6	GE320	GE320 - GP 2	CPF	New	1 000	-	2	800	
7	GE320	GE320 - GP 3	CPF	New	1 000	-	2	800	
8	GE320	GE320 - GP 4	CPF	New	1 000	-	2	800	
9	GE320	GE320 - GP 5	CPF	New	1 000	-	2	800	
10	GE320	GE320 - GP 6	CPF	New	1 000	-	2	800	
11	GE320	GE320 - 7	CPF	New	1 000	-	3	800	PETROAMAZONAS is in the process of purchasing these (most probably through a lease agreement with a purchase option).
12	GE320	GE320 - 8	CPF	New	1 000	-	3	800	
13	GE320	GE320 - 9	CPF	New	1 000	-	3	800	
14	GE320	GE320 - 10	CPF	New	1 000	-	3	800	
15	VHP 5900	MG 2101-1G	Limoncocha	Existing	750	250	1	600	**These six power generation units were operating under extreme critical deteriorated conditions** whereby PETROAMAZONAS was in the process of replacing these with diesel power generation equipment (part of the USD 17,000,000 used to purchase diesel generators). It is important to point out that the MG 21014G (future MG 2101-16G) suffered a fatal damage and is being replaced by a new engine. All these engines would definitely be scrapped by June 2009 in the absence of the project.
16	VHP 5900	MG 2101-2G	Limoncocha	Existing	750	250	1	600	
17	VHP 5900	MG 2101-3G	Limoncocha	Existing	750	250	1	600	
18	VHP 5900 (fatal damage)	MG 2101-4G** / 16 G	Limoncocha	Existing	1 000	250	3	800	
19	VHP 5900	MG 2101-5G	Limoncocha	Existing	750	250	1	600	
20	VHP 5900	MG 2101-6G	Limoncocha	Existing	750	250	1	600	
21	VHP 7104	MG 2101-11G	Limoncocha	New	1 200	-	1	960	None of these were in place prior to the Project Activity whereby the MG 2101-14G and 15G will replace the MG 2101-9G and 10G which are NOT suitable for asociated gas.
22	VHP 7104	MG 2101-12G	Limoncocha	New	1 200	-	1	960	
23	VHP 7100	MG 2101-13G	Limoncocha	New	1 000	-	2	800	
24	VHP 7100	MG 2101-14G	Limoncocha	New	1 000	-	2	800	
25	VHP 7100	MG 2101-15G	Limoncocha	New	1 000	-	2	800	
26	GE 320	GE320 - 11	Yamanunka	New	1 000	-	2	800	See observation GE320-7, 8, 9 and 10.
27	GE 320	GE320 - PAM 1	Yamanunka	New	1 000	-	2	800	Were purchased by PETROAMAZONAS whereby the generators in Yamanunka entered into operations in 2010 and the ones in Paka Sur will enter into operations in 2011.
28	GE 320	GE320 - PAM 2	Yamanunka	New	1 000	-	3	800	
29	GE 320	GE320 - PAM 3	Paka Sur	New	1 000	-	2	800	
30	GE 320	GE320 - PAM 4	Paka Sur	New	1 000	-	2	800	
31	18V34SG	ZAN 103	Eden Yuturi	Existing	4 500	2 500	3	3 600	These engines were operating with asociated gas without propper gas treatment and were at a point of having to be taken out of service. Today a large investment is being made to install i) compressors, ii) separators, iii) gas treatment plan and iv) gas storage. Bear in mind that Wartsila indicated from "day one" to the previous operator that **these engines were NOT designed to run on asociated gas**. These would definitely be taken out by June 2009.
32	18V34SG	ZAN 105	Eden Yuturi	Existing	4 500	2 500	3	3 600	
33	18V34SG	ZAN 107	Eden Yuturi	Existing	4 500	2 500	3	3 600	
34	18V32LN	ZAN 100	Eden Yuturi	New	5 000	-	2	4 000	These are crude engines that are being converted to gas / crude engines whereby part of the payments will be made with the income from CERs.
35	18V32LN	ZAN 102	Eden Yuturi	New	5 000	-	2	4 000	
36	18V32LN	ZAN 104	Eden Yuturi	New	5 000	-	2	4 000	
37	18V32LN	ZAN 106	Eden Yuturi	New	5 000	-	2	4 000	
				Total	**62 650**	**9 300**		**50 120**	**80%**

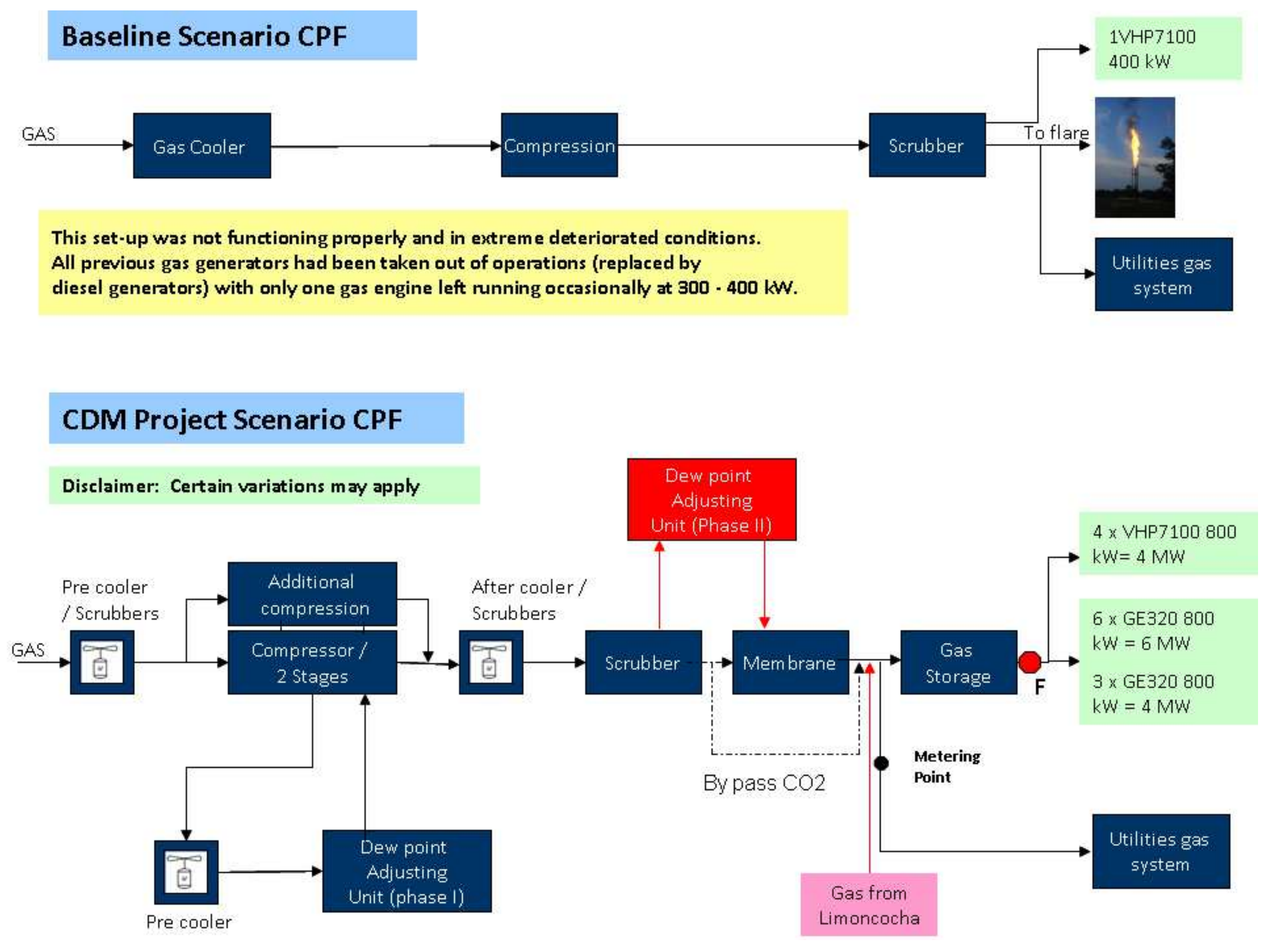
Central Processing Facilities (CPF)

Gas Handling:

- Re-engineering Gas Handling Facility
- Install additional Gas Compression Capacity.
- Install Treatment System.
- Incorporate Gas Storage Facility to compensate gas delivery fluctuations.

Electric Power:

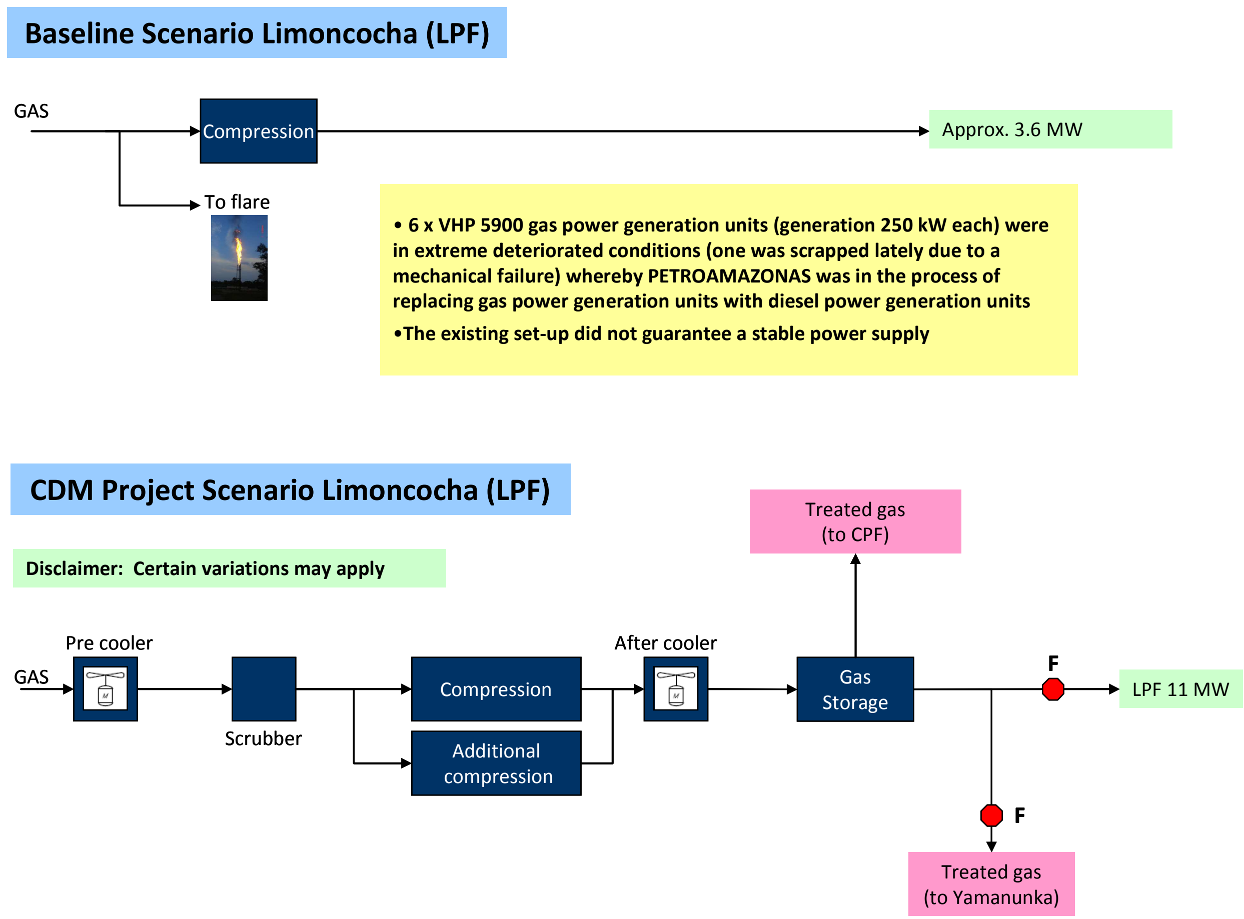
- Install Gas Power Generation System
- Incorporate Centralized Power Distribution System (13.8 kV) including Substations.
- Convert engine driven pumps (burning diesel) to electric motor driven pumps
- Transmission lines to Jivino B, Jivino F, Itaya, Limoncocha, Palmar Oeste and Yanaquincha



Limoncocha Processing Facilities (LPF)

Gas Handling:
- Re-engineering Gas Handling Facility
- Install Gas Treatment Equipment
- Install additional Gas Compression Capacity
- Incorporate Gas Storage Facility

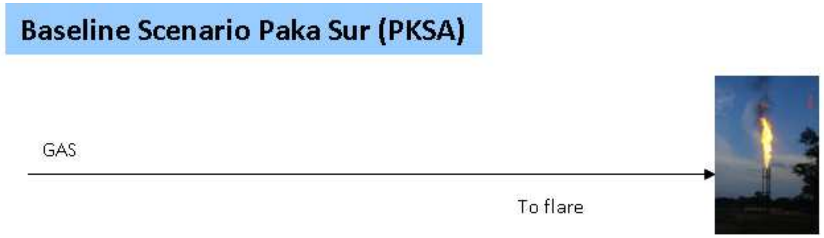
Electric Power:
- Upgrade Existing Power Generation Facility (6 x VHP 5900 en extreme deteriorated conditions).
- Install Additional Power Generation Capacity
- New Centralized Power Distribution System (13.8 kV)
- Substations
- Convert engine driven pumps (burning diesel) to electric motor driven pumps
- Transmission line between CPF and Limoncocha
- Transmission lines between Limoncocha and Yamanunka

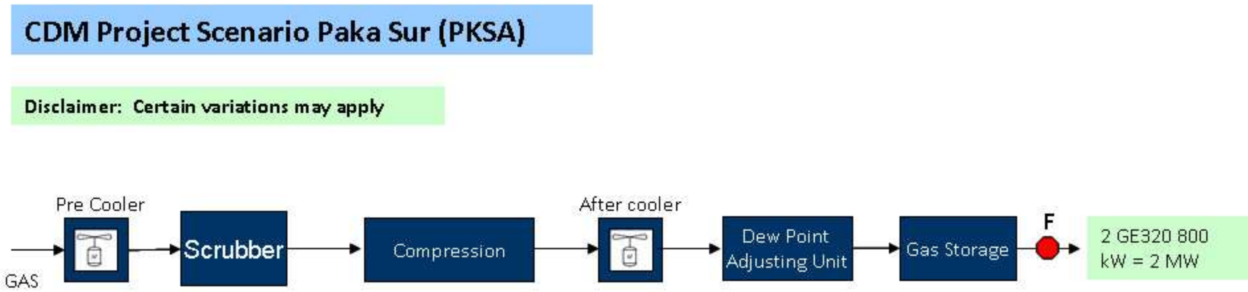


- **Paka Sur**

Gas Handling:
- Install Gas Compression System
- Install Gas Handling / Treatment System
- Install Gas Storage Facility

Electric Power:
- Upgrade Existing Power Distribution System
- Install Power Generation Capacity





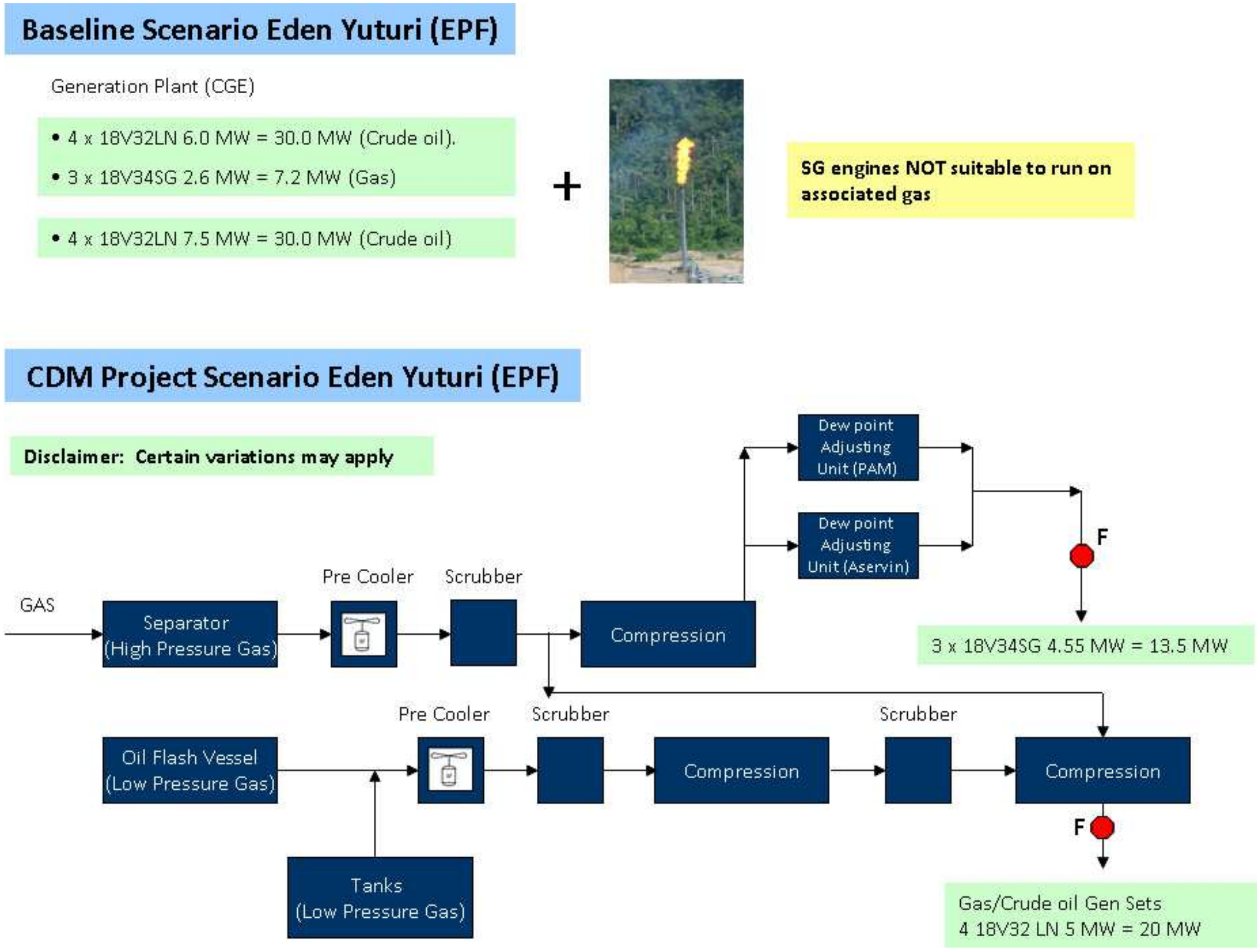
- **Eden Yuturi**

Gas Handling:

- Install Gas Handing (Compression and Treatment) System
- Low Pressure Gas Gathering and Handling System
- Install Gas Storage Facility

Electric Power:

- Install Gas Treatment and Upgrade SG engines to allow for power generation with associated gas.
- Convert Crude Engines to Gas / Crude Engines



Baseline Scenario Yamanunka (LMNK)

- Diesel generation (No generation with gas).

CDM Project Scenario Yamanunka (LMNK)

Disclaimer: Certain variations may apply