JOINT IMPLEMENTATION
PROJECT DESIGN DOCUMENT FORM

Name of the Project:

Utilization of Associated Petroleum Gas at the Vostochno-Perevalnoye Oil Field

Project Owner:
OJSC «Russian Innovation Fuel-Energy Company »
(OJSC «RITEK»)

Moscow, 2009

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Annexes

SECTION A. General description of the project

A.1. Title of the project:

Utilization of Associated petroleum gas (APG) at the Vostochno-Perevalnoye oil field, Western Siberia, Russia.
Sectoral scope 1,10
PDD Version 3.4,
Dated August 8, 2009.

A.2. Description of the project:

The project includes utilization of associated petroleum gas (APG) on modern power station with the general installed capacity 7,5 MW and on heating station with capacity 1,89 MW on Vostochno-Perevalnoye oil field (owner- OJSC "RITEK"), Surgutsky area, Khanty-Mansijsky Okrug - Yugra, Tumen oblast, Western Siberia, Russia (Figure 1a). Five Cummins QSV 91G generating units of 1.5 MW of nominal electrical capacity each are installed at the plant and three furnaces KVG 0,63 MW at heating station (HS). Power plant was designed specially for APG utilization. Generated energy (electrical and heat) ensures operation of all complex of the basic and supporting equipment on the oil wells and in well-exploiting settlement.

APG at the Vostochno-Perevalnoye oil field is obtained during the separation process at the booster pump station located next to the new power plant and heating station. The APG utilized within the Project was previously flared as shown in Figure 1. Within the Project, part of the APG (approximately 9,7 million m^3 per year) is used by the power plant and HS with the remaining APG flared as usual at the stack of the booster pump station. Power production for the needs of the project owner was initially ensured by the so called – powertrains PE-6M (mobile generating facilities consuming oil as a *basic fuel*). Heating was ensured by electric devices.

Figure 1. Project Gas Power Plant (GPP), (b), and the associated petroleum gas flaring at Vostochno-Perevalnoye oil field (a)
(a) (b)

Exploitation of Vostochno-Perevalnoye oil-field has begun in 1995. In 1998 oil-field was equipped with power-trains that until 2008 supplied power generation. Within the Baseline Scenario the growth of power consumption at the oilfield was supposed to be covered by additional powertrains – roughly 5 power trains of 1 MW capacity each. This scenario constituted the cheapest solution, with total cost of 5 additional power trains not exceeding 0,9 mln. Euro.

Still the Project Owner opted for other ways of APG utilization that were analyzed and assessed within 2003-2004. Partly the refusal from the baseline scenario can be attributed to the innovation profile of the project owner - OJSC RITEK within its mother Group LUKOIL. RITEK has been chosen as a testing ground for advanced technological and environmental solutions within the Group, which presupposed additional costs that were spent often regardless of the profitability considerations. In our case the related research and feasibility study job was commissioned by the project owner to the NIPIGazpererabotka research institute. The project alternatives developed by the Institute combined solution of the problem of APG utilization and electricity generation. The option chosen by the project owner presumed construction of GPP.

With the costs considerably risen within the new options for APG utilization-based power generation the issue of financial viability of the project have been raised on the corporate level. One of the possible ways to ease the financial burden was to use the opportunities of the Kyoto protocol market mechanisms, namely the Joint Implementation within the Article 6. The related perspective of the Russian participation in the JI mechanism became clear in September 2003 as long as the Russian Government Climate Change Commission initially approved the first version of the JI National Regulations for the Russian Federation. This was a clear signal for the business stakeholders concerned and the project owner has chosen the Kyoto market opportunities to ease the APG utilization costs. The related income was taken into consideration within the corporate financial decision making arrangements on the project implementation.

After the corporate corporative decision on the exploring alternative solutions for APG utilization including those involving the Kyoto market mechanisms, taken on the meeting of the RITEK Technical Board on 25.09.2003 the development and technical design works have started, later followed by the construction phase (see the Table 2 (b) below).

Commissioning of the related feasibility study by the project owner to the NIPIGazpererabotka research institute (Krasnodar, Russian Federation), contract concluded on 29.09.2003. The preliminary report of this study was issued in December 2003, the final report was ready by May 2004. The project alternatives examined by the Institute combined solution of the problem of APG utilization and electricity generation. The option chosen by the project owner presumed construction of GPP.

The design was performed by the JSC Giprotyumenneftegaz. (Tyumen, Russian Federation). Commissioning of the full-cycle work on the first block of the power station in Vostochno-Perevalnoye to JSC “Zvezda-Energetika” (Saint Petersburg, Russian Federation), contract concluded on 07.06.2007. The job was to be executed on turnkey basis and presumed design, manufacturing of equipment, construction, assembly and launching into operation the power station (GPP), based on the Cummins reciprocating engines. HS was commissioned in the beginning of 2008 (January).

In addition to the GHG emission reductions, the Project contributes to sustainable development of the host country by promoting the utilization of wasted APG which can be a valuable energy resource. The Project also leads to the reduction of local pollutants such as CH_4, CO, NO_x, through reduced gas flaring and more efficient combustion of the APG by the environmentally friendly low-emission gas engines and boilers of HS.

The supplier of APG to the GPP and HS and the purchaser of electric power and heat produced is Project Owner – joint stock company RITEK.

The electricity users are mainly groups of pumping stations, which are maintaining oil reservoir pressure by pumping water into the reservoirs 24 hours a day, and other facilities ensuring oil production and transportation at the oil field. Well-exploiting settlement consumes heat from HS. This requires the GPP generating units to operate 24 hours per day to meet the demand. Delivery of electricity to the external grids is not reasonable from the technical point of view (as the oil field is located far from the nearest Transforming Station (PS), which makes unprofitable any possible construction of a grid for sales of insignificant volumes of additional energy). Besides, in Russia there is no legal mechanism to support the alternative power generation, and the tariff for electric power in grid (in case if it approved by the regional energy committee - REC) is calculated on the base of return of investment within 10 years. With the above factors taken into consideration, the power and heating stations are meant to operate in an autonomous regime.

The basic operating mode presumes that four units are operating at station (at an average of 80% of total capacity). One unit is kept as a reserve capacity. The general electric energy production, taking into account the electric power consumed by GPP for own needs, makes 34.100 MWh per year. Station own power consumption is regulated in line with Russian National norms (SNIPs), as 20 kWh per every MWh produced. The general own power consumption, thus, makes – 0,7 GWh per year. Emergency power supply for GPP is provided be emergency diesel-generator with installed capacity 0,28 MW, and (partly) from powertrains that can consume APG, and also other liquid fuels – diesel, crude-oil.

Main part of electric power is delivered to the ZRU-6kV distribution installation and then to the transformer substation 6/0,4 kWA and further on power facilities of the local consumers. The total installed capacity of the energy-requiring equipment is 9,85 MW. Average rate of operation is ≈ 0,5 of the total capacity. Heat, from HS, consisting from 3 furnaces – KVG 0,63 MW each (one of them provides hot water, second – peak consumption, third – considered as reserve), transports to well-exploiting settlement (at distance 130 m). Average coefficient of consumption ≈ 0,5, but significantly varies from 0,2 (summer) and ≈1 (winter).

The Project will contribute to sustainable development of the host country by promoting the utilization of wasted APG which is a valuable energy resource and will reduce CO_2 and CH_4 emissions in two ways:

- Utilization of the APG in the efficient power & heat generating facilities instead of its flaring,
- Substitution of crude-oil combustion in power generation by APG which has a smaller CO_2 – emission factor.

Estimated total reductions of GHG emissions will be around 62,322 tonnes of CO_2- equivalent (tCO_2e) per year (including 29388 tons CO_2e in 2008) and respectively 311,610 tCO_2e within the 2008-2012 crediting period.

A.3. Project participants:

OJSC «RITEK» - project owner (investor) and power station operator.

According to the license agreement OJSC "RITEK" is the owner of associated petroleum gas.

OJSC «RITEK» is responsible for Joint Implementation Project and for implementation of the monitoring plan.

Table 1: Project participants

Party involved	Legal entity project participant (as applicable)	Please indicate if the Party wishes to be considered as project participant (Yes/No)
Russian Federation (Host party)	OJSC "RITEK"	**No**
Not indicated	-	-

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A.4. Technical description of the project:

The project consists of Gas Power Plant (GPP) with installed capacity of 7,5 MW, heating station TKU-1890 with installed capacity 1,89 MW, and necessary facilities for APG pre-treatment and transportation. Necessary electrical equipment is used for power delivery to the consumers.
A list of key project components is provided in Section A.4.2.

A.4.1. Location of the project:

The project is located in Russkinskoye county, 200 km north from the Surgut city in the Khanty-Mansijsky autonomous Okrug (KhMAO) - Yugra, Tumen oblast, 2,400 km from Moscow (see fig. 2).

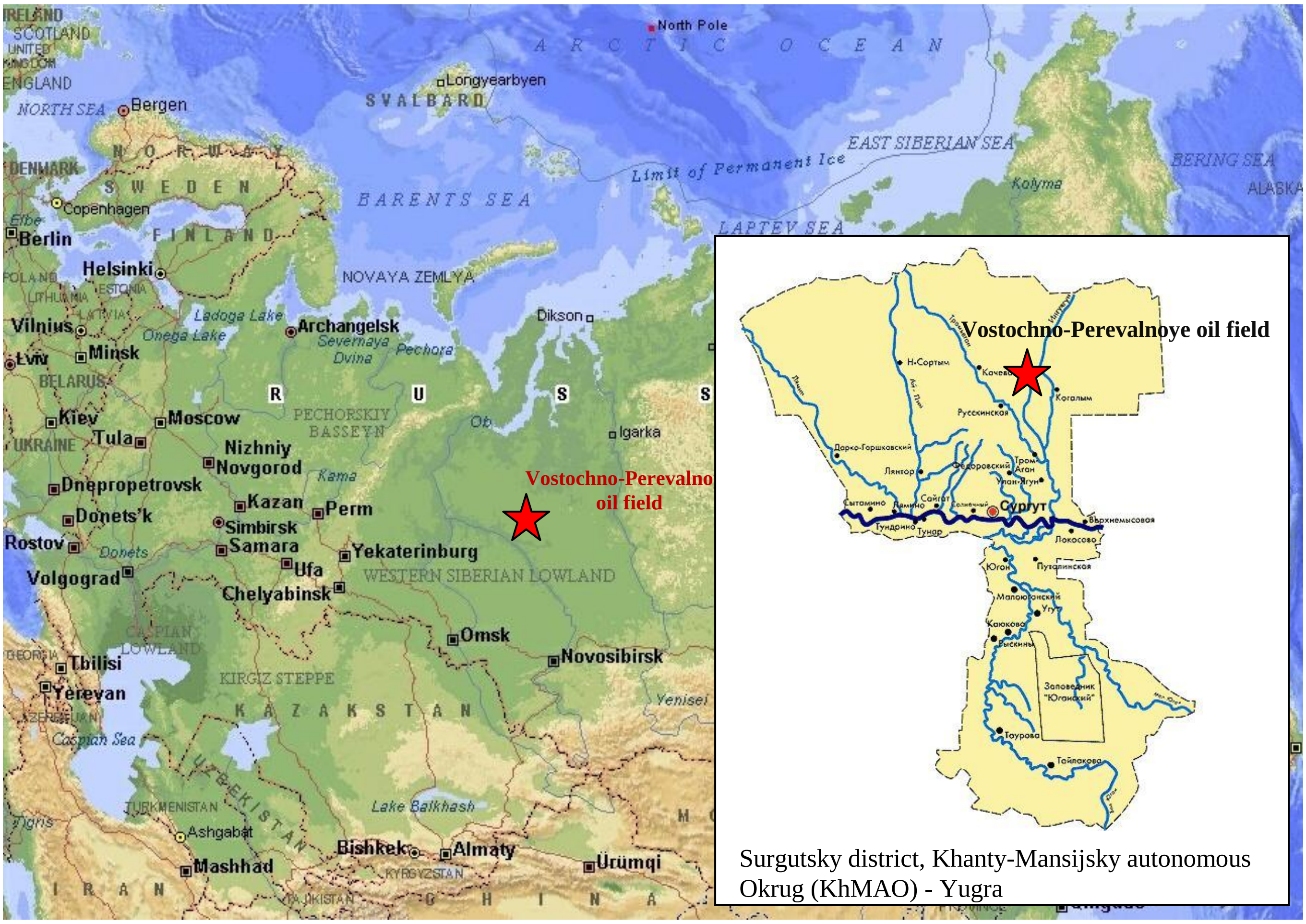
Site latitude - 63°14'39". Site longitude - 72°49'55". Vostochno-Perevalnoye oil field located on basin of river Tromyegan in boggy district. Oilfield consists of two parts – West Cupol and East Cupol. Present project design document considers second one – East Cupol.

Figure 2.

General view

Of oil field

Figure. 3. **The location of Project**



Surgutsky district, Khanty-Mansijsky autonomous Okrug (KhMAO) - Yugra

A.4.1.1. Host Party(ies):

Russian Federation

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

The Khanty-Mansijsky Autonomous Region (KhMAO) is situated in the medial part of Russia. It occupies the central part of the West Siberian plain. The capital of the region is the city of Khanty-Mansijsk. KhMAO is a sparsely inhabited area with a population density of 2.8 persons per square km. The total population of 1,488,500 people is spread across 534.8 thousand sq. km. Nearly 86% of the region's population lives in 16 cities.

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

Surgut is a city in the Russian Federation, administrative centre of the district - Surgutsky, KhMAO-Yugra, Tumen region, largest city in KhMAO, one of very few Russian cities that are bigger then the regional capital (Khanty-Mansiysk), both in terms of population and industrial potential.

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

The Surgutsky district occupies the central part of the Western-Siberian plain and crosses by the biggest region's river – Ob'. The climate of Surgutsky district —is sharp-continental. In this a case it can be determined as a moist (spring and summer), with intensive circulation of air-masses: north winds in summer, south and south-west all other seasons. Just because of this region famous by a unexpected temperature changes, which annual amplitude of fluctuations makes 75 degrees by Celsius scale.

Average temperature of the coldest month - January – 22,1 degree below zero, and the warmest — July — nearby 16 degree, average annual temperature is 6,2 degree below zero. An absolute minimum — 56 degrees below zero, an absolute maximum — 35 degrees above zero.

The basic riches of Surgutsky area are the oil, partly natural gas; other minerals in its territory include sand, clay and raw materials for construction-materials industry. The oldest and largest (of the country) oil fields are located in Surgutsky district (first one was – Ust'-Balykskoye); geological works on which have been started in 30th (of 20th century), and exploitation 50 years ago. Largest from them are Fedorovskoye, Yuzhno-Surgutskoye. 100 mln tonnes of high-quality oil extracted on approximately 100 oil-fields. That provides ≈20% of total Russian's oil resources.

Eleven fuel/energy companies work on the territory of Surgutsky area, such as YuganskNefteGas, KogalymNefteGas, NoyabrskNefteGas, MegionNefteGas, TomskNeft, RITEK and on of the biggest in the country – JSC Surgutneftegas.

A.4.2. Technology (ies) to be employed, or measures, operations or actions to be implemented by the project:

The 7,5 MW of installed capacity of the Project consists of 5 * 1,538 MW gas-fired reciprocating engines (Cummins QSV 91G). The gas engines are connected with HVS824 electric generators.
Transportable heating station (HS) consists of three furnaces-boilers KVG (furnace-boiler for water heating) 0,630 MW each.
The major components of the Technological Solution within the Project design are summarized in Table 2.

Table 2: Project components (a)

Equipment type	Quantity	Parameters	Notes
Power-block			
GPP - QSV 91G Cummins, manufactured by JSC «Zvezda Energetika»	5	1,538 MW_e per unit. efficiency$_э$ 38,2%, estimated expenditure of gas 293 nm cubes/MWh	The gas-reciprocating engines are equipped with inner cooling .
Gas power plant automated control system (ACS)	1	ACS includes the control system of each generating	The GPP ACS ensures: 1- Operational control of the GPP by automated workstation and monitoring of

		unit, the synchronization system of the units and the GPP control system.	technological processes at the power generating units, switch gears (6 kV, 0,4 kV, inhouse transformer); 2- Retrospective evaluation of GPP's operation mode; 3- Timely detection of emergency situations with precise indication of the damaged areas.
Transformers 0,4/6 kV	24	6 kV, capacity 100-630 kWA.	For electricity consumption and for delivery to fiders
Fire fighting and alarm System	2		The Project is implemented in compliance with the existing norms and standards for explosion and fire fighting requirements and ensures operation safety
Communications	1		Radio relay equipment is applied
Emergency diesel-generator	1	0,28 MW, 0,36 kV voltage.	Provides emergency generation (for GPP and HS)
Heating Station TKU-1890			
Furnace-Boiler	3	0,63 MW, efficiency-92%, estimated expenditure of gas 129,5 nm cubes/GCal, heated water temperature 60-95°C, V – 3,5 kPa	No need in additional furnace insulation, works on a self draft (without induced draft fan)
Gas burner automatic GBG 0,70	3	Three phases of heat power regulation	With automated control system on the base Siemens controller
Circulation pump WILO	1	Heat water injection	
Pre-treatment Block			
APG treatment facility (Atom-Converse)	1	....	The APG fuel gas to GPP and HS
Flare stack of low pressure	1	Ø=150mm	
Flare stack of high pressure	1	Ø=100mm	
Tank for diesel fuel	1	V=2000m^3	

Table 2. (b) Implementation schedules

#		2003		2004				2005				2006				2007				2008		
				Quarters				Quarters				Quarters				Quarters				Quarters		
1	Corporate decision on feasibility study preparing 25.09.2003																					
2	Business planning phase																					
3	Corporate approval																					
4	Design project																					
5	GPP installation																					
6	HS construction																					
7	HS commissioning																					
8	Project commissioning																					

There is no need of additional training of monitoring staff as the main measures and activities connected with project monitoring close to common (routine) practice.

A.4.2.1. Characteristics of the GPP's basic components

The main components of the GPP are:

- QSV 91G Cummins gas-reciprocating engines produced by *JSC Zvezda Energetika*,
- Stamford HV824C generators
- Fuel gas supply system.

Ten -18 cylinders, four stroke, high speed gas engines with electric spark ignition have been chosen, in part, because of their tolerance for lower quality APG-fuel and because of low pollutant emissions in the exhaust gas. The fuel gas supply system of the GPP, including gas pipelines (isolated for leakage minimization) and the APG treatment plant, is designed to support normal operation of the power generating units using APG. Each unit is equipped with a device that switches off fuel supply sources in emergency cases. The fuel gas flow rate at 100% load is 293 nm^3/MWh. The fuel gas (APG) is taken from the gas pipeline of the APG treatment plant into the engine's gas mixer where air is added. The mix is then transported by pipe into the turbo-blower. Then, the compressed gas-air mixture goes through the cooler into the fuel suction line that distributes the mixture among the engine's cylinders. Design pressure at the fuel supply inlet is 3.5 Bars with temperatures from 10 to 20 degrees Celsius. The fuel used at the GPP is APG that is separated at the Vostochno-Perevalnoye booster pumping station. Minimal CH_4 index without decreasing power is 52 %. APG after separation is divided in two flows with one part directed to the GPP and the other flared at the existing stack of the booster pumping station.

Before use in gas-engines, APG must be processed at the treatment plant by:

- Drying from dropping liquids while being heated up from +10 to +20°C,
- Reducing pressure from 0,5 MPa to 0,35-0,4 MPa,
- Gas filtration.

No incremental electric use is needed for gas treatment and transport due to the Project. The pressure at which gas comes into the APG treatment plant is sufficient to push it through the system. Heating of the gas is fully covered through use of waste heat from the gas engines.

Figure. 5 Block of QSV 91G Cummins

Electrical Interconnection Systems

The GPP includes the following electrical equipment:

- 10 generators;
- 6 & 0,4 kV gears;
- 6/0,4 kV transformers;
- in-house transformer substation with 0.4 kV distributor switch gear (for self consumption)

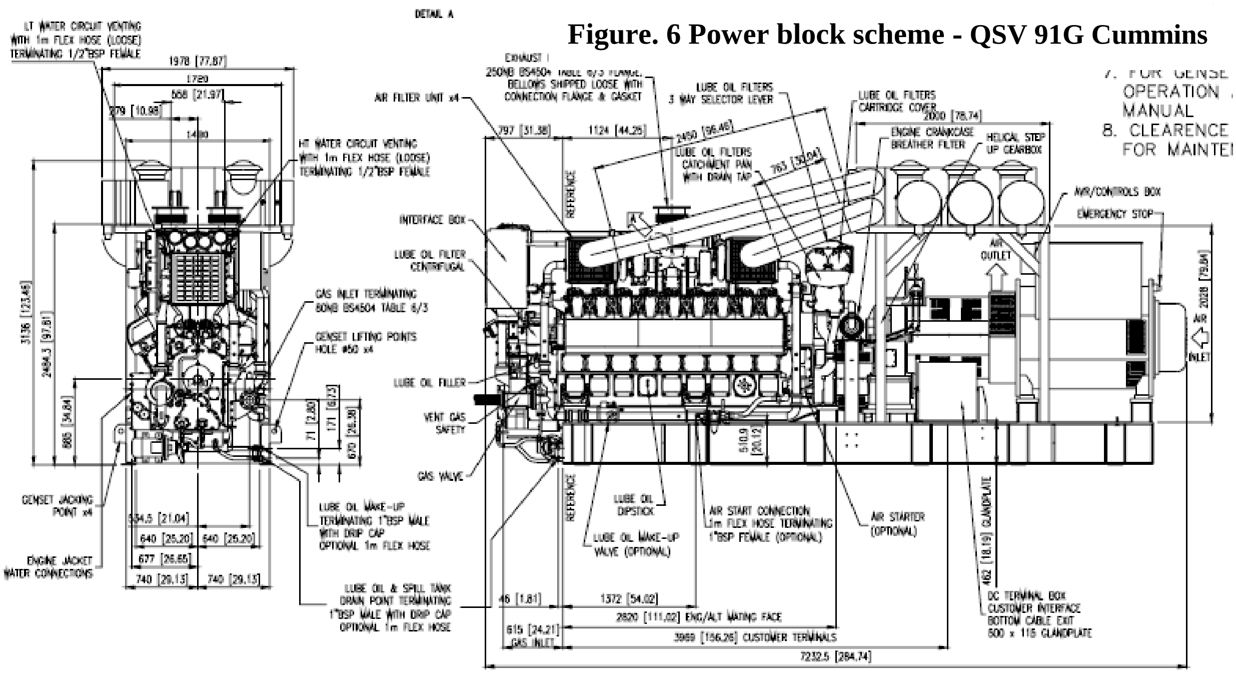


Figure. 6 Power block scheme - QSV 91G Cummins

Delivery of the electricity to power consumers is provided from transforming station, voltage 6 kV. Total annual consumption from the given substation is estimated as 34,1 GWh/year. Own power consumption of the station is approximately 0,7 GWh/year. Power supply for own needs is provided from external feeders on voltage 380 V. Electric power is delivered to the ZRU-6kV distribution installation and further on by 6 kV cables to the related transformers and facilities. The average distance to consumers 2,5 km. In case of emergency switch-off of a gas supply system, or in other cases of absence of gas in APG processing facilities, consumers will be supplied from diesel-generator. Transition to emergency operation of work in GPP occurs in case of critical pressure drop in the gas pipeline.

In case of GPP transition to work the emergency diesel fuel the emissions are calculated according to the actual expense of fuel and nameplate data on received emissions.

Electric power delivery in external grids, and also stabilization of voltage due to interconnection to high-voltage transformers in foreseeable prospect is impossible, because of very high expenses (exceeding cost of the power station), and difficult procedure of the coordination of generating object inclusion into external networks.

Heating station is transportable boiler, consisted of three steel furnaces 0,63 MW (0,54 Gcal) each. Expenditure of gas per 1 Gcal (while heating from 70°C to 90°C) –129,5 nm cub (0,155 tons of fuel equivalent; efficiency - 92%). Every furnace equipped with automatic gas-burner providing necessary graphic of fuel injection. HS needs no operating personnel.

Significant advantage of HS – is easy to assemble on site. Such heating stations are usually installed nearby consumers and because of this there is no necessity of excessive investments in pipelines (for district heating).

Delivery of the heat to consumers in well-exploitation settlement is provided by pipes insulated with poly-urethane foam. Losses are insignificantly small due to very short distances, and also due to good present condition of equipment. Because of heat controller's absence at consumers' present losses can be estimated as 2%.

Figure 7 represents technological scheme and monitoring point locations for the Project facilities: pre-treatment block, GPP, HS. The description of the monitoring points is provided in Table 3 following the diagram.

A.4.2.2. Technological flow diagram

Figure 7 represents technological scheme and monitoring point locations for the Project facilities. The description of the monitoring points is provided in Table 3 following the diagram.

Figure 7: General scheme of the Project

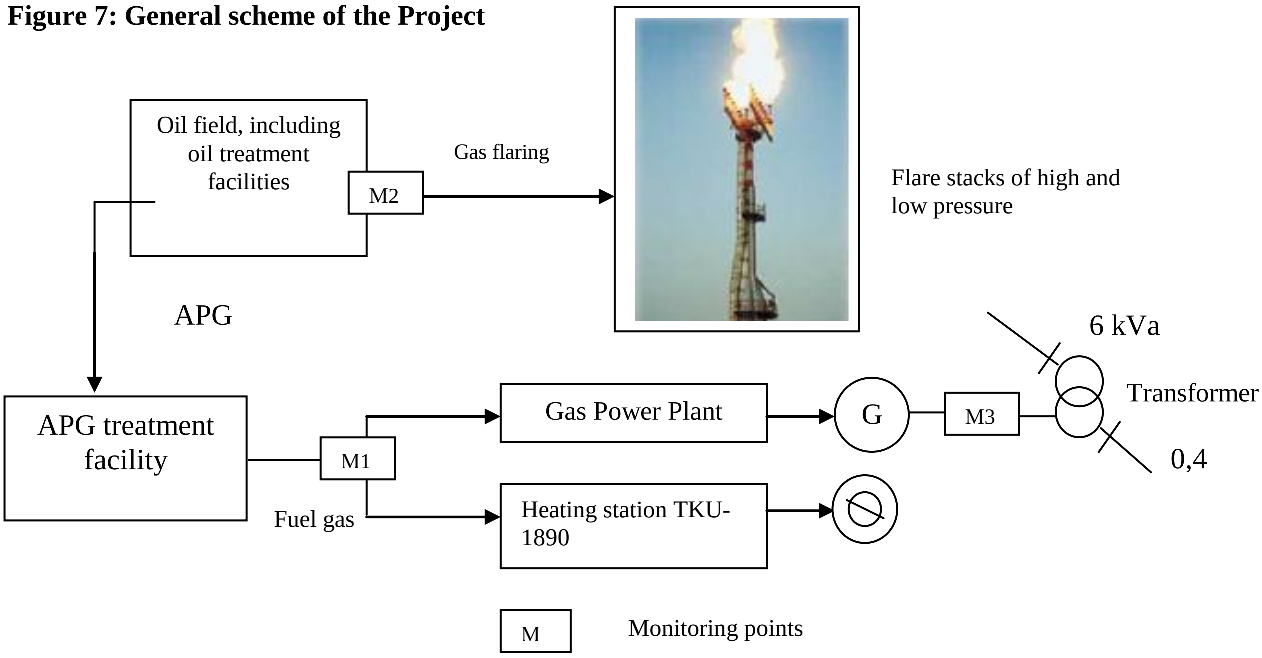


Table 3: Description of monitoring points

Monitoring Point	Location	Parameters to monitor	Quantity | year	Metering equipment
M1	Pre-treatment block (exit)	Gas volume explicated in normal cubic meters	Actual volumes (9,7 mln cubic meters for 2009)	Flowmeter
M2	Flare stack	Flaring on a stack superfluous gas volume and pressure	Actual volumes	Flowmeter,
M3	Feeders on GPP	Electricity delivery	34,1 GWh	Electricity counter SET 4TM

A.4.3. Brief explanation of how the anthropogenic emissions of greenhouse gases by sources are to be reduced by the proposed JI project, including why the emission reductions would not occur in the absence of the proposed project, taking into account national and/or sectoral policies and circumstances:

In the baseline scenario circa 9,7 million m^3 of APG will continue to be flared annually at the Vostochno-Perevalnoye booster pumping station. In the Project scenario, this volume of APG is captured and burns in the installed gas engines to supply 34.100 MWh of electricity per year to support pumping requirements for the Vostochno-Perevalnoye oil field and 8940 Gcal (from heating station) of heat for well-exploiting settlement. In the baseline scenario, an equal amount of electricity will be generated by the powertrains which are fuelled by crude oil and heat will be generated by electric heating devices.

GHG emission reductions, that will be included in the calculation of the emission reductions due to the Project, will occur in two locations (see table 4):

• Reductions at the Vostochno-Perevalnoye field will occur because the captured APG that was previously flared will be combusted in the gas engines with much higher efficiency than it is in the local flare. This will generate the emission reductions due to the combustion of the unburned fraction of the APG that was previously directly escaping into the atmosphere from flare stack.

• Reductions will also occur since the crude oil combustion in powertrains for power generation will be changed to combustion of APG that has lower GHG emission factor.

Table 4: Ex ante emission reduction estimates

Items	Units	Baseline Emissions (index b)	Project Emissions (index p)
APG flared/combusted	1000 м^3	9,676	9,676
Complete combustion of APG	tCO_2	23372	30081
Unburned APG in terms of tCH_4	tCH_4	904	-
Unburned APG in terms of tCO_{2e}	tCO_2	18994	-
Total local emissions	tCO2	42366	-
Net fuel consumption (tons equivalent fuel)	Tuf	27119	-
Power trains emissions\heating station	tCO_2	58270	-
Total emissions	tCO_{2e}	100637	30081

Flare combustion is less efficient than more tightly controlled combustion in gas engines (and modern furnace). However, there are no international standardized methods of precisely calculating such emissions from readily available data. Therefore, calculations of the methane emissions from flaring of APG captured and utilized by the Project is based on the “Methodology of calculation of emissions of hazardous substances into the atmosphere due to the flaring of the associated petroleum gas at flaring stacks” developed by St-Petersburg Institute for the Air Protection (NII Atmosfera) and endorsed by state committee for environmental protection – “Goskomekologiya”. This methodology has been approved and endorsed by the Decree of the Russian National Service of Hydrometeorology and Environmental Monitoring (# 199 of 08.04.1998) and adopted from 01.01.1998 as the appropriate basis for reporting hazardous emissions from flaring of APG.

Mentioned above methodology is the most widely accepted approach used by the Russian oil and gas industry. It provides all relevant parameters, algorithms and measurement requirements to calculate the emissions of hazardous substances (including methane emissions) that are accounted in the project baseline as a result of the incomplete combustion of the APG. The calculation of methane emissions is based on the following parameters:

• Technical parameters of the stack and characteristics of APG (flow rate, composition, density) and of the APG components (density, molecular mass, adiabatic index, carbon mass content, etc).

• The mode of APG combustion (subject to non-black firing test). The non-black firing test is implemented to determine the quantity of methane emissions vented into atmosphere due to low combustion efficiency of the flare (under-firing). Black-firing mode refers to under-firing to a degree that flare emissions contain significant soot and under-fired hydrocarbon emissions, including methane. The methodology provides default factors for the emission rates for both non-black firing and black-firing combustion. These factors are the integral part of the approved methodology and were established on the basis of the program of on-field measurements for the industrial flare stacks in Russian oil and gas industry.

Current national policies provide minimal incentives to oil producers in Russia to use APG more efficiently or to reduce flaring. The main obstacles for APG flaring reduction projects in Russia are as follows (see also the Section B.1 of the PDD):

• Regulated prices for APG at the entry of gas processing plants are too low to encourage development of new APG transport and processing facilities. These prices remained non-revised from their 2001 level until now at the range of 2.8 to 17 USD/1000 m^3 depending on liquids content. The Russian Federal Tariff Regulation Office drafted new marginal wholesale prices on APG for 2007. According to this draft, minimal marginal tariffs range within 5-29 USD/1000 m^3, and maximal marginal tariffs are within 6-39 USD/1000 m^3 depending on liquids content. In accordance with RF Government Ordinance # 59 dated 09/02/2008 state regulation was eliminated. However with the free pricing introduced formally the problem of low price did not disappear due to the advantages of the buyers (gas processing plants) due to their location.

Hence, the Project, even within the most favorable circumstances (maximal world oil prices, low APG prices), cannot be assessed as commercially viable; according to the calculations of its commercial profitability below, it generates net operational losses due to the difference in investments payback time between the baseline (roughly 5 years). Calculations for this period show additional costs for the project line compared with the baseline, that can be treated as operational losses (from the baseline viewpoint see the Investment Analysis below). With this in mind we may conclude that the Project is financially unattractive for the Owner.

• High investment costs and inadequate returns of APG utilization projects compared to other highly profitable alternatives for the oil companies. The facilities for the utilization of the APG were usually not integrated in the oil field production schemes and may imply a construction of the new infrastructure for collection, treatment, and transport of the APG. These investments tend to be uneconomic for remote oil fields with limited local energy needs and long distances to the gas processing facilities or consumption markets. The oil companies also face structural barriers such as limited access to the existing gas transmission infrastructure and low prices for the APG negotiated with the transmission companies or gas processing facilities. Another key obstacle for efficient APG utilization in Russia is lack of effective provisions on APG utilization in the existing exploration licenses granted to the oil companies. Though APG utilization is prescribed by major part of licenses, the related measures cannot be considered as compulsory, since the due enforcement mechanism is lacking. Large volumes of APG continue to be flared despite the respective license provisions and the current rate of APG utilization in Russia remains relatively high only on the old oilfields, developed in the 70-80-ies when the APG utilization facilities were constructed within the framework of a state policy obligatory for the state-owned oil industry. In the 90-ies and later the rate of APG utilization fell drastically and no real sanctions followed. Not a single case of an exploration license annulated due to low APG utilization by any oil company was recorded through the history of the Russian Federation. In case of the Rosneft oil company, for example, only in 2008 violation of conditions of 161 license agreements was detected, but not a single license was annulated (sources www.newchrmistry.ru. www.vedomosti.ru).. The high-ranking statesmen confirm the situation. Mr. Yuri Trutnev, Minister of Natural Resources &Environment, commented lately upon this issue: “ It seems to me that last 15 years we got used to irresponsibility of the oil companies, that are used to orient themselves…not on legislation and normative documents (source: www.mnr.gov.ru/files/part/5470_doc2.doc*)*. The same view is shared by Alexander Filippenko, Governor of the Khanty-Mansiisk Autonomous District (Yugra), where the Project is located. He noted, that the license agreements turn into a document bearing no real commitments for the users of the oilfield (source: www.rusoil.ru/.../o06-44.html*)*.. Absence of risk of license withdrawal for the license holder is confirmed also by the law makers, e.g. Valeri Yazev, Chair of the State Duma Energy Committee speaks in favor of developing the law that could ensure this type of legal enforcement, and this clearly confirms that currently this option is not legally enforced. Therefore though the APG utilization was prescribed for Vostochno-Perevalnoye oilfield within the License Agreement, the project activities cannot be attributed to business as usual scenario, since the terms of the License Agreement do not exert any real pressure on the Project Owner towards APG utilization (source: http://www.edinros.er.ru/er/text.shtml?44781*)*. Therefore, these circumstances, treated in accordance with JI Guidelines urging the baseline to be set with due regard of the national and/or sectoral policies and circumstances and economic situation in the project sector (Guidelines for the Implementation of the Article 6 of the Kyoto Protocol, p. 2(c) Ap.. B, Annex to Decision 9 CMP1), should explicitly mean lack of the legal enforcement on APG utilization within the licensing framework as one of the circumstances of the national economic situation in the oil sector in Russia (see .B.1 section for further details).

- Low environmental fees for the emissions of polluting substances during APG flaring. According to Amendments to the Governmental Decree of 12.06.2003 # 344, issued on July 2005, the fee rate for methane emissions contained in APG flared by stationary sources is 250 rubles (about 10 US dollars) per ton of methane equivalent. Mentioned fee rate was applied for basic investment analysis. This level of environmental payments does not imply any significant impact on the investment decisions of the oil companies. Since January 1, 2012 fee rate will be increased by the RF Government Decree #07, dated 08.01.2009. In accordance with Decree fee rate since 2012 will grow up considerably for every ton exceeding 5% limit of APG flaring.

Taking all this into account, including local specifics, e.g.: absence of GPP operating experience by the Project owner (present GPP already generating electricity on RITEK's oil-fields managing by outsourcing entities), high investment costs of the project, relatively high operation costs, the Project cannot be considered as economically attractive for the Owner. Therefore its implementation in the mode described above can be explained only by its environmental importance, including intentions to reduce the emissions of GHG.

A.4.3.1. Estimated amount of emission reductions over the crediting period:

The total estimated greenhouse gas emission reductions to be achieved by the proposed project –311,610 tonnes of CO2 equivalent over the period 2008-2012.

Table 5: Ex ante estimates of emission reductions by year

Length of the crediting period	**5 years**
Year	**Estimate of annual emission reductions in tonnes of CO_2 equivalent**
2008	29388
2009	70566
2010	70566
2011	70566
2012	70566
Total estimated emission reductions over the crediting period (tonnes of CO2 equivalent)	311610
Annual average of estimated emission reductions over the crediting period (tonnes of CO_2 equivalent)	62322

A.5. Project approval by the Parties involved:

All necessary approvals will be obtained later in accordance with Decree #332 from May 22, 2007.

SECTION B. Baseline

B.1. Description and justification of the baseline chosen:

This section defines and justifies the selected baseline scenario following the Annex B of the JI Guidelines and the JISC "Guidance on criteria for baseline setting and monitoring". The baseline is established on a project-specific basis using two main steps:

- By identifying and listing alternatives to the project activity on the basis of conservative assumptions and taking into account uncertainties;

• By identifying the most plausible alternatives considering relevant sectoral policies and circumstances and other key factors that may affect a baseline. The screening of the alternatives is based on analysis of the technological and economic considerations, as well as on the prevailing practices.

Step # 1. List alternatives to the project activity that can be a baseline scenario.

The decision making context of the Project includes two entities:

• Project owner, which operates the Vostochno-Perevalnoye oil field, has flared the APG before the Project.
• the GPP, receiving gas from gas pre-treatment unit, generate electric power for own consumption of the oil field.

Since the project is carried out on the oil field situated far from main networks (gas, power) which could change a number of Project – related issues, the Owner of the project can be determined as a monopolist, who doesn't have alternatives in the mode of the project implementation; therefore it appears appropriate to consider given parameters and figures as average (similar) for the region.

The APG produced at the Vostochno-Perevalnoye oil field can be treated in the following possible ways by Owner or with involvement of a third party:
1. Continuation of APG flaring at with power generation provided by the powertrains. This is the business-as-usual scenario, used by the overwhelming majority of the oil and gas companies in the situation similar to the Project owner's one (RITEK has operated powertrains on this oil field until October 2008).
2. The proposed Project - reduction of APG flaring installation of the GPP - electricity generation and heat (due to HS) for the local needs using the APG.
3. The GPP Project could be developed on the base of gas turbine technology instead of four-stroke reciprocating engines.
4. The GPP Project could be of a smaller or larger scale in case if it could be commercially viable.
5. Reduction of APG flaring and re-injection of APG into oil wells.
6. Reduction of APG flaring and delivery of APG by the Project owner to the gas processing plants for conversion to dry gas, LPG, or condensate for downstream utilization, or delivery of the APG to the gas transmission pipelines.
7. APG combustion by existing powertrains for electric power generation.

These options cover all of the alternatives for baseline identification that are listed in CDM methodology AM0009, for example. The comparison of AM0009 alternatives and the list above is as follows:

Table 6: The comparison of AM0009 alternatives and the possible alternatives to the Project activity

AM0009 Alternatives	Options considered as possible alternatives to the Project activity
Release of APG to atmosphere (Venting)	Not considered
Flaring at the Project site	Option 1
On-site APG utilization	Options 2 through 4
Injection into oil reservoir	Option 5
Transportation, processing, distribution to end users	Option 6

Venting is not an acceptable option for this project because it is not legal under Russian regulations. Therefore, this is not a plausible future scenario.

Options 3 and 4 test technical Project variants to provide robust assessment of which options are the most plausible future developments that involve on-site electric generation.

Re-injection and downstream processing are the alternatives available to the RITEK as owner of the APG without the project, and complete the list of possible options to be considered.

Step # 2. Identifying of the most plausible alternatives considering relevant sectoral policies and other key factors that may affect a baseline.

1. Continuation of APG flaring at the oil field and supply of the power needed for local facilities by the powertrains.

The specific feature of the oil field is the proximity of the APG sources and the oil field facilities to the GPP. All customers also (pumping and other facilities) are located within 0,3 -6 km from GPP. At the same time the nearest high voltage grid – LEP - situated far from oil-field, and that makes energy consumption from external distributors unprofitable. Above this, technical connection to external networks presents a serious problem and involves high additional costs (200-400 $ per 1 kW of power capacity).

Since 2003, (after adoption of the new State Law on Energy Sector Reform) the country is experiencing fast growth of prices for power that gave an additional reason for the Owner to develop in-house generation facilities.

Currently, economic incentives are insufficient to attract most oil companies to efficiently use APG. No tax for APG flaring is imposed on oil companies. The only payments oil companies are required to make are the environmental fees for emissions of the polluting substances (i.e. methane) into the atmosphere. These fees are extremely modest compared to the investment costs required to productively utilize the APG. The current methane fees for flared APG per barrel of oil produced are less than 1.0% of the sales price of a barrel of oil. Thus, methane fees for flaring will have no major influence on decisions regarding oil production and related APG output, even with the perspective of their rise in accordance with the Government Decree # 7 of January 8, 2009, taken into account.

Likewise, the APG utilization provisions within the License Agreement cannot be treated as a real motivation in favor of the APG utilization, since the respective provisions are not legally enforced. In the 90-ies and later the rate of APG utilization fell drastically compared to the 80-ies and no real sanctions followed. Formally the APG utilization provisions are included into the License Agreements on major part of the newly-developed oilfields, but no cases of an exploration license annulated due to low APG utilization by any oil company has been reported so far in the Russian Federation. The figures show that out of 53- 55 billion m^3 of APG produced annually in Russia, about 45% is purchased by gas processing plants, 26% is utilized at the oil fields, and more than 25% is flared. A similar rate of utilization of the APG is observed in the KhMAO. This provides clear evidence that APG utilization provisions within the License Agreements within the framework of the "Combined tool to identify the baseline and assess additionality" (Version 02.2) CDM EB 28 Annex 14 p.5, can be described as a regulatory requirement that is systematically not enforced and non-compliance with this requirement is widespread in the country, and therefore the APG utilization Project activities in this case are additional and only the continuation of APG flaring can be attributed to the baseline scenario.

Oil producers in this region can earn very high returns on investment, expanding oil production and are much more likely to allocate funds to production rather than to less financially attractive APG utilization facilities. According to the head of the Gas and Natural Resources Department of Khanty-Mansijsk Autonomous Okrug, the payback on investment in oil production tends to be less than one year. No APG utilization projects are likely to offer a similar return.

In addition to the overall sectoral circumstances, the following project-specific arguments suggest that continued flaring at the Vostochno-Perevalnoye field is a highly probable future scenario through 2012 and beyond as long as current economic and regulatory conditions prevail:

- Traditionally problem of power supply on this oil field was effectively solved by powertrains, combusting crude-oil as fuel, since it was and continues to be the cheapest solution.
- There are two gas processing plants or APG in Surgut (at distance 200 km), but no available networks in the immediate vicinity to the Vostochno-Perevalnoye oil field. No plans exist to construct them in the nearest future. Thus, considerable additional investments would be required to transport and process APG for downstream utilization, that don`t have a commercial perspective, given the volumes of the APG at the oil field.
- The technological solution in oil mining at the Vostochno-Perevalnoye oil field presumes use of water to maintain pressure for oil extraction. Additional investments are needed to replace water with APG for injection; this option was considered by the Project Owner on the business planning phase (1998-2005) as the remote perspective, going beyond the Project timeframe. Thus, possibility of further APG flaring exists, and can be considered as a cheap alternative to the Project.

2. The proposed Project presuming the reduction of APG flaring, construction of the GPP and power generation for the local needs using the APG, that is currently implemented by the Project Owner.

It should be noted that the Project Owner already possesses the experience of on-site electric generation at some oil fields, for example on Sredne-Khulymsk oil field. However, in this case the choice has been made, taking into account the local specifics, namely the absence of access to external grids. In this case the Power plant operates in an independent mode, and power supply of each well is provided by the cable-lines that are connected with power distribution facilities of the GPP.

Within the investment analysis approach and cost assessment provided in Section B.2 (Investment analysis sub-section), the total Investment cost for the Project Owner is estimated at 7,3 million Euro. The project at existing costs is below the threshold of profitability existing for the first class borrowers for crediting period - project planning (7 years for a full recovery at 14 % annual). The NPV calculation within the Investment Analysis for the Project shows negative amount of EUR -7.150.000. This clearly demonstrates that the project is not economically attractive to the Initiating party. The possibility exists for the Initiating party to compensate a part of the Project costs by using the Kyoto mechanisms, namely the Joint Implementation. This opportunity was considered at a stage of business planning of the Project.

At the same time using powertrains according to baseline scenario would mean total investment costs around 860 thousands euro for the same generating capacities, that is essentially cheaper and making tthis option attractive from the financial viewpoint. Beside this, installation of power trains does not require considerable time for design, and for the project implementation as a whole. The project of power station on the basis of PE-6M is a typical certified technological solution, requiring no additional environmental assessment & expertise. It is necessary to mention also that the project planning phase within the corporate decision making procedure within the Project Owner took place in 2004 when the prices for crude-oil were below the level 30$ barrel and therefore, the potential revenues from the additional volumes of oil were considered to be lower the level needed to compensate the costs of the Project. All this gives ample ground for conclusion, that the Project Owner did not have sufficient economic reasons to investments in the Project, and Project implementation was not considered to be economically efficient alternative.

3. The installation of gas turbines instead of gas engines for power generation using APG.

This alternative was not considered by the Project Owner as technologically realistic, though the turbine solution had some advantages, including smaller size and smaller costs for MW installed. Still, the Project Owner explored this option and rejected the gas turbine technology for the following reasons:

- The efficiency for gas turbines (GT) is (usually) not higher than 32%, compared to 38-40% for Cummins engines operating at full load. Steam-gas cycle (that can raise total efficiency) is appropriate when the GPP has possibility to deliver power to external networks. But since it is not so, and internal consumption is characterized by significant fluctuation in demand, the gas turbines seems to be not inappropriate for this.
- The climate of Western Siberia is harsh with severe winters and warm summers. The temperature varies from - 40°C through + 20-25°C, and these changes do affect the GT efficiency that drops by 15-20%. On the contrary, Cummins has a high degree of resistance against the temperature changes, keeping its efficiency parameters high and steady.
- A Cummins engine can be started up and halted without limitation. Starts and halts do not affect the length of service of the engine. As for the GT, the situation is different; 100 starts of the GT reduce its service life by 500 hours.
- The service life until the overhaul for a GT is 20,000 - 30,000 hours, whereas for a Cummins engine it is 60,000 hours.
- Specific equipment costs, fuel consumption rates and O&M expenses for GT in this size range are higher than those for a Cummins.

Co-generation (combination heating station and GPP) was also considered by Project’s owner. But oil field has it own specific. It’s operated by well-exploiting watch settlement that has no necessity in significant volumes of heat (approximately third part of traditional settlement consumption). That is why main part of heat (produced as co product of electricity generation) will be wasted. Besides exploiting HS is transportable heating station, and this solve much problems connected with project works, maintains and the main problem – heating networks. Investment expenses on HS installation less then investments on heating block in co-generation plant in five times.

Based on these findings, development of the Project with gas turbines replacing the gas engines is not more attractive than the Project as proposed. If the Project, as proposed, does not offer competitive returns, the gas turbine variant will certainly not be attractive. The GT alternative is not a plausible future scenario for the Project since the Cummins option proves to be more efficient and reliable.

4. Construction of larger GPP with increase in quantity of utilized APG and sales of a part of the electric power to external consumers/ construction of a smaller size GPP.

The larger size option presumes competition with local power networks that appears to be not realistic. The key power company Tumenenergo is the transit grid system connecting the West and the East of the Russian Federation, because of this any admission of alternative power producers and power suppliers (even, despite the lack of capacities) is extremely complicated. Russia is operating a two-level power network system, in which low voltage grids (less than 220 kV), are subordinate to the federal grids – FSK UES (220 kV and more). Connection to high voltage grids are possible, however it is this possibility exists in reality only for «big power plants» (200 MW and over). Connection to local distributive networks is inconvenient, since they are overloaded and operating mode of power station will be complicated in these frameworks, since it will be defined by regional dispatching management (RDU), and the generating equipment will therefore operate in an unstable regime, delivering low-quality power.

Besides that, the expenses needed to construct interconnecting cable lines (to high voltage grids or distribution networks) are considerable and comparable to expenses for the GPP itself. The mechanism of compensating these costs does not exist in Russia. Until 2007 the ownership of networks constructed by independent power suppliers, was bound to be that of the local grid company, that assumed the property rights (free of charge) shortly after the construction of each related line. It should be also acknowledged that power production of the GPP depends on stability or instability of APG-production, and stability of APG quality; since both cannot be totally guaranteed, the GPP as an independent power producer cannot provide guaranteed quantities and quality of power, and this unreliability can cause penal sanctions from the grid operator.

The first case of establishing national regulations targeted to support investment projects in the field of power generation presumed introduction of in addition investment extra charge to the power tariffs. However, currently this mechanism has been approved exclusively for the Kaliningrad region ("Yantarenergo"power company) for TEC#2. This case is unique due to the region's isolated location. There were no other cases of introduction of similar policies in Russia so far.

Therefore the Project is based on independent (autonomous) generation mode. Until the GPP's commissioning in 2008 August, local electricity consumption was provided by powertrains, which will be further considered as a reserve and emergency generators. GPP was designed for present consumers, so any future increasing of consumption will be guaranteed with power-trains.

Investment costs for the Project do not depend linearly on the station sizes. In general, the average expenses per 1 MW decrease as long as the station size grows. The chosen variant with 4 engines in constant operation, 1 reserve one is optimal, as long as smaller GPP couldn't satisfy the peak demands, which is definitely one of the key requirements for a new power generating facility. This clearly demonstrates that construction of a smaller size GPP can not offer an environmentally friendly and technologically reliable option for the Project.

5. Reduction of APG flaring and re-injection into the oil reservoirs.

Re-injection of associated petroleum gas into oil reservoirs is one of the methods to increase oil extraction, as it helps maintain reservoir pressure. The technological solution in oil mining at the Vostochno-Perevalnoye oil field presumes use of water to maintain pressure for oil extraction. APG injection as an option was considered by the Project Owner on the business planning phase (2003-2004) as the remote perspective, going beyond the Project timeframe. At the Vostochno-Perevalnoye water injection system is operating efficiently; this system includes a group of pumping stations that are constantly pumping the water into the oil reservoirs. These stations consume the power delivered by the GPP within the Project.

Given the considerable costs invested by the Project Owner in water injection infrastructure, taking into account local hydrology, climate and the low cost of water used for this purpose, the APG re-injection can not be considered as economically attractive alternative for the Project Owner. Still, possibility of re-injection of APG in reservoir is now being considering by Project's owner (as a technological experiment), but perspective of commercial use of this technology is distant and is definitely outside the Project timeframe.

There were only few precedents (three) all over CIS with realization of cycling-process (gas injection in oil well) – Novotroitzkoye oilfield (Ukraine), Kukmol and Aryskum (Kazakhstan). Due to achieved results efficiency of such technological decision still looks unconvincing (from the economic point of view), including also potential revenues from ERU sells. The reason – is very high energy chargers necessary to provide enough pressure on the well's mouth.

Therefore, this option can not be considered a plausible future scenario.

6. Delivery of APG to gas processing plants or to a gas transporting pipeline.

Implementation of this scenario is an unlikely due to following reasons:

- APG delivery to the nearest gas processing plant located in the city of Surgut at a distance of 200 km from Vostochno-Perevalnoye oil field requires huge investments, of many millions. For example construction of 1 km of the gas pipeline could cost 1,0-1,5 million €. Thus the total cost of the gas pipeline would require an investment of 200 to300 million €. The volumes of AP gas available at the oil field are definitely not enough to guarantee a pay-off of such a project.
- Construction of a new gas processing plant at this site would also be excessively expensive. Based on available data, we can assume that construction of a gas processing plant for a comparable volume of APG would cost 28-40 million euros. The Vostochno-Perevalnoye APG has an attractive composition due to significant fraction of gas liquids. This fraction (20% of APG volume) can be effectively sold on the market. But remaining part of APG - methane - can be transported from the oil field only in the liquefied form. However there is no necessary infrastructure for liquefied gas transportation in Russia. The necessary national technical regulation (TU) for this type of gas transporting is not developed yet, and this presents an additional problem, especially taking into the related hazard effects of methane. Thus, the economic benefits of such option are not obvious.
- There is a gas pipeline (main – Urengoy – Chel'abinsk) nearby to oil field location that belongs to JSC "Gazprom". However access to them and perspective of their use for APG sales, are not clear due a number of constraints. APG from Vostochno-Perevalnoye can not be delivered to gas transporting pipelines without preprocessing needed to change it in accordance with pipeline transportation standards - GOST for natural gas. Even with this done, the supply to the gas transmission pipelines of Gazprom could face barriers due to the risk of facing limited access to the gas transmission infrastructure, taking into account the lack of free capacities in Gazprom system.

In addition, Gazprom generally accepts to pay a low price for the APG that may not be enough to cover the costs needed to develop the related infrastructure for gas collection, treatment and transportation. And above all, additional gas volumes from an outside producer being injected in the Gazprom transport system at the Gazprom key gas producing region, actually means decrease of revenues of state monopoly. All this reduces chances of this similar scenario of APG treatment practically to zero.

7. APG utilization by the existing powertrains.

This variant, being more expensive, than baseline one, is less environmentally friendly, than the project scenario. Its implementation would lead not to reduction of fuel consumption, but to its growth. Numerous generation capacities create, being unified, a certain complexity both technical and organizational. Absence of a local-external power supply grid would result in increased losses of the electric power, no-result work of generators. All this would result in general an additional growth of fuel consumption up to 15 - 25 percent. Besides, all existing schemes of powertrain fueling are based not on pure APG, but on using either pure oil, or a combination of oil with APG. Thereby the goal - APG utilization, presumed by the project, would not be reached completely in terms of volume. At the same time, with the efficiency of power trains PE-6M averaging 66-70% of the efficiency of GPP "Cummins", the fuel consumption for electric power generation at project level was essentially more in this option than within the Project. Besides, the given variant would provide development of expensive system of APG pre-treatment which is absent in the base scenario. Thereby, it is possible to define that the given variant cannot be considered as a real alternative to the project from the environmental point of view and cannot be considered as realistic alternative to the baseline scenario from the economic point of view.

Conclusion:

Based on above considerations, the only option can be regarded as plausible and credible candidate for the baseline scenario at this site:

• Option 1: Continuation of APG flaring at the Vostochno-Perevalnoye oil field with power needed by the Project Owner generated by the powertrains.

Data/Parameter	$V_{F,y}$
Data unit	Nm^3
Description	Volume of the total recovered gas measured at point M2, after pretreatment, during the period *y*
Time of determination/monitoring	Monthly
Source of data (to be) used	Flow meter
Value of data applied (for ex ante calculations/determination)	9676000 nm^3
Justification of the choice of data or description of the measurement methods and procedures to be applied	Measurements effectively show volume of APG that would be flared in frames of baseline. It is typical procedure using for settlements between Project's owner and GPP's exploiting company (Zvezda Energetika).
QA/QC procedures (to be) applied	Volume of gas will be completely metered with regular calibration of metering equipment. The measured volume should be converted to the volume at normal temperature and pressure using the temperature and pressure at the time to measurement.
Any comment	-
Data/Parameter	Vi
Data unit	(%)
Description	Composition, of recovered gas measured at point M2, after pretreatment, during the period *y*
Time of determination/monitoring	Twelve times a year
Source of data (to be) used	Measurement providing by authorized company
Value of data applied (for ex ante calculations/determination)	Vi (shown below)
Justification of the choice of data or description of the measurement methods and procedures to be applied	Basic figures for calculations meters by authorized company on its chromatograph, at the junction point and at exit from pre-treatment block. Annual figures will be the APG volume weighted averages of twelve-times a year figures.
QA/QC procedures (to be) applied	**QA**: measurements from the flow meters is screened on monitors at the operator's desk; readings are taken by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration by the regional representatives of State Office for Metrology and Standardization
Any comment	-
Data/Parameter	Gen El.
Data unit	MWh
Description	Electricity supply to consumers at Vostochno-Perevalnoye oil-field on voltage 6 kV, and electricity supplied for self consumption 0,4 kV.
Time of determination/monitoring	Monthly
Source of data (to be) used	Electric meters
Value of data applied (for ex ante calculations/determination)	34080 MWh
Justification of the choice of data or description of the measurement methods and procedures to be applied	Electric meters are installed at the 6 kV (0,4 kV) in-door switch gears, data will be archived electronically and in monitoring workbook.
QA/QC procedures (to be) applied	**QA**: measurements from the electricity meters is screened on monitors

	at the operator's desk; readings are taken by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration of the meters by the regional representatives of the State Office for Metrology and Standardization
Any comment	-
Data/Parameter	Voil
Data unit	Tuf (tonnes of equivalent fuel)
Description	Volume of crude oil to be combusted in accordance with baseline to provide current electricity and generation.
Time of determination/monitoring	Annually
Source of data (to be) used	Total electric power & heat generation multiplied on coefficient 0,596 (tuf per MWh)
Value of data applied (for ex ante calculations/determination)	27,119 tuf
Justification of the choice of data or description of the measurement methods and procedures to be applied	Procedure using for estimation of total fuel consumption by powertrains. Average coefficient based on results of official audit carried out in 2006.
QA/QC procedures (to be) applied	Typical procedure in national power generation sector. Calculations providing by trained specialists of the Project owner.
Any comment	-

B.2. Description of how the anthropogenic emissions of greenhouse gases by sources are reduced below those that would have occurred in the absence of the JI project:

To demonstrate that the proposed JI SSP will reduce the GHG emissions below those that would have occurred in the absence of the project, two steps are implemented:

- Step #1: Investment analysis of the Project based on calculation on NPV (net present value) for the Project.
- Step#2: Comparison of the GHG emissions that would occur due to the project activity and in the baseline scenario.

The results of the Investment analysis of the Project based on calculation on NPV (net present value) for the Project are presented in the Table below.

Years	years		1	2	3	4	5	6	7	8	9	10	11
Years	years		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Investments	Euro	7300000	4380000	2920000									
Share of equipment	%	60%											
Discount	%	14%											
Annuity	Euro	0			0	0	0	0	0	0	0	0	0
GPES production	MWh			8525	34100	34100	34100	34100	34100	34100	34100	34100	34100
Electric energy to cover electric needs	MWh			8525	34100	34100	34100	34100	34100	34100	34100	34100	34100
Total elecrric energy to cover needs	MWh			8525	34100	34100	34100	34100	34100	34100	34100	34100	34100
Baseline expenses per MWh	Euro/MWh		15	15	15	15	15	15	15	15	15	15	15
Baseline energy cost ('revenue)	Euro		0	127875	511500	511500	511500	511500	511500	511500	511500	511500	511500
					0	0	0	0	0	0	0	0	0
Project Operation cost	Euro	na	0	179000	716000	716000	716000	716000	716000	716000	716000	716000	716000
Project cost	Euro	21083000	4380000	3099000	716000	716000	716000	716000	716000	716000	716000	716000	716000
Cash (revenue - cost)	Euro	-11236625	-4380000	-2971125	-204500	-204500	-204500	-204500	-204500	-204500	-204500	-204500	-204500
IRR													
NPV													

Years	years		12	13	14	15	16	17	18	19	20	21
Years	years		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Investments	Euro	7300000										
Share of equipment	%	60%										
Discount	%	14%										
Annuity	Euro	0	0	0								
GPES production	MWh		34100	34100	34100	34100	34100	34100	34100	34100	34100	34100
Electric energy to cover electric needs	MWh		34100	34100	34100	34100	34100	34100	34100	34100	34100	34100
Total elecrric energy to cover needs	MWh		34100	34100	34100	34100	34100	34100	34100	34100	34100	34100
Baseline expenses per MWh	Euro/MWh		15	15	15	15	15	15	15	15	15	15
Baseline energy cost ('revenue)	Euro		511500	511500	511500	511500	511500	511500	511500	511500	511500	511500
			0	0	0	0	0	0	0	0	0	0
Project Operation cost	Euro	na	716000	716000	716000	716000	716000	716000	716000	716000	716000	716000
Project cost	Euro	21083000	716000	716000	716000	716000	716000	716000	716000	716000	716000	716000
Cash (revenue - cost)	Euro	-11236625	-204500	-204500	-204500	-204500	-204500	-204500	-204500	-204500	-204500	-204500
IRR												
NPV		-7 159 030										

Step #1. Investment analysis of project without carbon revenues

The investment analysis is performed to assess the additionality of the Project. This analysis is based on calculation on NPV (net present value) for the Project giving a detailed vision of the degree of its financial attractiveness to the Project and taking into consideration the investment costs, operation costs, amortization and other parameters referring to expenses, including the discount taken at the rate of 14% (rate applicable to the first rate corporate borrowers at the major banks at the stage of the corporate decision making on the Project).

- *Annual revenues* for Vostochno-Perevalnoye oil-field project are calculated based on the amount of money saved due to exclusion of costs needed for power trains to produce the equivalent of the amount of power generated within the project by GPP. This is calculated on the basis of the power costs per 1 power train equal to circa EUR 100.000 p/a including fuel and operation costs with the assumption of 5 power trains to be needed to cover the equivalent of the annual project power generation.
- *Annual costs* for RITEK are calculated on the base of servicing fees to be paid to the company executing the technical servicing of the GPP. According to the respective concluded contract, it equals EUR 716.000 p/a, with the first servicing year starting on October 1, 2008 (that is reflected in the related table – see above)

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Taken into account was also the amortization rate taken as 10%. With all the above costs and revenues taken at the level specified above, the Project shows negative profitability for the whole of its lifetime ending in 2027.

Even at the end of the Project lifetime the revenues cannot exceed costs , and the NPV for the Project period is as low as – 7.159.000 EUR. With this degree of financial unattractiveness the Project can by no means be a part of Business-As-Usual scenario for the Project Owner.

Sensitivity Analysis

Sensitivity Analysis is added for the conservativeness reasons to confirm the robustness of the financial additionality of the Project. The sensitivity is tested against the dynamics of costs for substitution by power trains of the power generated within the Project. These dynamics basically reflect the level of the fuel costs since the price of the oil consumed is the key component of these costs. The first scenario presumes - 20% fall of the respective costs and shows the following project economics : with these conditions the project becomes still less attractive for the Project Owner, with the NPV reaching -7.694.000 EUR.

In the second scenario, presuming rise of respective costs by 20% the Project still remains unattractive from the financial viewpoint with NPV at the level of – 6.623.000 EUR. In this connection the project can be described as economically unreasonable for the Owner.

Analysis of the impact of the regulatory norms of the Russian Federation introduced after the date of baseline setting. On January 8, 2009 the Government of the RF has issued a decree # 7 " On the measures of stimulation of the reduction of atmospheric air pollution by the by-products of associated petroleum gas flaring on stacks" that sets starting from 1.01.2012 a considerably higher payment rates for APG flaring above the prescribed norm of 5%. Analysis of impact of this regulation shows that supposed that for the whole amount of the APG flared within the baseline, that is considered to be above the prescribed norm with the respective payment rate, the annual baseline expenses within this scenario will grow by EUR 73.000. This will bring down the NPV slightly up, but no more then 1% depending upon the scenario chosen from the above ones, leaving the NPV level essentially negative. This gives a reason to conclude that the new regulation produces no sizeable effect upon the financial attractiveness of the baseline and financial disadvantage of the project for the Owner.

Emissions reduction (ERU) sales within the Project can add to its attractiveness in terms of return on investments within the Project line; a possibility also exists to increase incomes of the company by revenues from ERU sales in the post-Kyoto period, after 2012. It is worth noticing, that incomes from the sales of reductions will raise attractiveness of the Project for the Owner and will create a precedent which can be further repeated by the other oil companies in KhMAO.

Step #2. Comparison of the GHG emissions that would occur due to the project activity and in the baseline scenario

The previous section demonstrates that the most probable option in the absence of the JI project is the continued flaring of 9,8 million m^3 of APG that the JI project would have used for electric and heat generation. Given this baseline scenario, baseline and project emissions of GHG can be compared as follows:

Table 9: Baseline and project scenario emissions

Comparative Item	**Units**	**Baseline scenario**	**Project scenario**
APG flared/combusted	1000 m^3	9,676	9,676
Complete combustion of APG	tCO_2	21402	30081
Unburned APG in terms of tCH4	tCH_4	904	-
Unburned APG in terms of tCO2e, *(c*21)*	tCO_2	18994	-
Total Local Emissions	tCO_2	42366	-
Power (electricity) consumption by oil field	GWh	34,08	34,08
Heat consumption by oil-well settlement	GWh	10,395	10,395
Power trains emissions	tCO_2	58270	
Total emissions CO_{2eq}	tCO2	100637	30081

Calculations based on representative historical data show that the Vostochno-Perevalnoye flaring is performed in black-firing mode and that the APG produced here is ≈76% methane (by volume). The detailed calculation methodology then indicates that flaring of 9,7 million m^3 per year of APG at oil field will lead to emissions of 904 tCH_4 due to under-firing and 21,402 tCO_2. Conversion of CH_4 to CO_2e using an IPCC global warming potential factor of 21 then indicates baseline local emissions due to flaring of 42,366 tCO_2e.

The Project supplies 34,08 GWh of electric power p/a for local consumption on the Vostochno-Perevalnoye oil field. As power supply within the baseline and the Project is meant to be carried out in an independent (autonomous) mode, the internal losses of 9%, are taking into account within the actual amount of power produced and consumed. In this case the annual electric power generated is calculated brutto and in the baseline it is assessed as consumed.

The baseline scenario supposes the electric power for the Vostochno-Perevalnoye oil field to be generated by the PE-6M powertrains with standard capacity of 1050 kW (See Fig. 10). This solution combined with local power grids is the most widespread type of power supply in the oil fields of the region. PE-6M equipped with diesel-engines D-49 (produced by Kolomna Machinery Plant), and upgraded by company – "Konver", to work either on diesel either APG or crude oil (in gas-diesel cycle).

For a number of remote locations in Russia powertrains (in a few cases – diesel power stations) are the only available source of power supply. Partly modernization of D-49 was realized by specialists of Project's owner, and after that patented (Patent RF #2215176). Nowadays approximately 30 trains are in exploitation.

Trains are fueled by oil with physical-chemical features as follows:.

Parameter	Value
V (20°C, kg/m^3)	858,5
Viscous (20°C, mm^2/s)	13,59
Molecular mass g/mole	211,51
Cool down temperature, °C	1
Sulphur	0,87
Pitch silicagelic	10,12
Asphaltens	1,45
Paraphynes	3,37
Water	0,7

Figure.10. Powertrain PE-6M

The gross power generation required within baseline is equal to 34.100 MWh p/a. The key parameter needed for baseline calculation is - the actual fuel use by the powertrains for generation; it is estimated at 0.596 tons of unified fuel equivalent per 1 MWh. Fuel consumption for this amount of power within the baseline is estimated as 20,311 tonnes of equivalent fuel (tuf.) per year.

At the same time fuel consumption by HS equals 6,808 tuf. p/a (11423 MWh/ 0,596 tuf/MWh). Total fuel consumption thus 27,119 tuf. p/a. Such fuel consumption makes total energy use at 794594 GJ (27,119 t*29300 MJ/tuf – calorific value of equivalent fuel). Available default carbon content for crude oil according to 2006 IPCC Guidelines for National Greenhouse Gas Inventories is 20kg/GJ. Last step estimation of CO2 emissions. 794594 (kg)*20 (kg/GJ)*44/12/1000 makes emissions at 58,270 tCO_2*e.*

Total baseline emissions are then 58,270 + 42,366 = 100,637 tCO_2*e* per year.

Combustion of APG in the gas engines is much more efficient than in flare. The project uses the approach from the previously approved CDM methodology AM0009 version 2 and assumes full oxidization.

PE,y = (*Vy*Py) * Wcarbon,A,y *44/12*

Where:
Vy – volume of APG to be flared
Py – density of APG

Thus, 10745 (tAPG) * 0,763 (cAPG) * 44/12 = 30081 tCO_2

Total Project CO_2e emissions: 30,081 tCO_2e

The estimate of annual reductions in GHG emissions is then 100,637 – 30,081 = 70,566 tCO_2e.

While the NII "Atmosphera" methodology for calculating flare emissions is widely recognized as the standard for the Russian oil and gas industry, it relies centrally on the chemical composition of the APG being burned and on continued operation of the flare in black-firing mode. Since the gas engines within the Project have been specifically designed for the APG of Vostochno-Perevalnoye, the long term purchase contract includes clear specifications of fuel composition and GPP staff regularly monitors compliance with these specifications. No significant variations in fuel composition are anticipated during the period from 2008 to 2012 (Project crediting period) although this will be monitored monthly and emission reductions will be tied to composition of the fuel actually received.

As discussed in the Annex 4, the black-firing test depends on the physical dimensions of the flare stack, the volume, adiabatic index, molecular mass and temperature of the APG being flared, and the discharge velocity of the flared gas. Since the flaring will continue within the Project, the necessary data for this test will be provided on a regular basis. However, some significant changes in the mode of operation of GPP may require reconstruction of the stacks. Since there is no significant motivation for RITEK to change the mode of operation of the flare or to invest in reconstruction, it is assumed that black-firing mode will continue. GPP will provide monthly dated photographs of the flare as evidence that no major reconstruction has occurred. In that case, the assumption of continued black-firing is appropriate. If significant reconstruction does occur, GPP will request the necessary data from the Project Owner to determine whether black-firing is still the appropriate. Future flare reconstruction is considered highly improbable.

The Project reroutes APG that flows to the flare in the baseline through the gas treatment plant, the gas engines (furnaces) and ultimately through the gas engine stacks. Obviously this Project routing offers some opportunities for emissions due to leakages and/or accidents in the delivery, cleaning and combustion of APG.

However, the Project APG pipeline is only ≈1 km. It was built according to the modern standards, including those for insulation. Therefore, leaks have been ignored to assure that emission reduction estimates are on a conservative basis.

Common Practice. Actually there was a number of projects implemented in Russia since 2004 in APG utilization and some of them took place in the region with roughly similar conditions as Vostochno-Perevalnoye project, the similarity considerations could be true only for the projects with the similar size and taking place in the same region (KhMAO – Yugra). The fact that this region is the key oil producing region in Russia (57% of the Russian oil is produced in KhMAO), confirms these considerations.

The overall situation with APG utilization in KhMAO is characterized by large-scale projects undertaken by the JSC Surgutneftegaz, the local leader in this type of activity and technolgy. Still, it should be noted that the APG utilization projects undertaken by Surgutneftegaz, are large size ones, some facilities exceeding 2000 MWh power capacity. The projects of similar size and with similar type of engine with the Serginskoye on include i.a. :

	Oil-field	Region	Project owner	Brief description
1	Yuzhno-Myldzhensk oil-field	KhMAO	JSC Russneft	GPP consists of 3 engines GE-Jenbacher 0,88 MW each. Annual APG utilization 5 mln.m3. Commissioned in 2007.
2	Yeguriakhskoye oil-field	KhMAO	JSC Russneft	Commissioned in 2007 GPP engines GE-Jenbacher with total installed capacity 4,25 MW (5*0,85).
3	Kholmistoye – Chatylkinskoye oilfields	KhMAO	JSC Gazprom Neft	Commissioned in 2008 APG utilization over 15 mln ncm. p/a

The difference between the above mentioned examples and situation with Vostochno-Perevalnoye oil-field is on the type of energy substituted by the GPP within the project. The Vostochno-Perevalnoye project is targeted to substitute the power generated by burning of crude oil by the power from APG utilization, while the above mentioned projects had a goal of substitution of the already existing diesel generators, that used expensive diesel fuel that was supplied to the oilfield sites at a considerable costs (given the general transportation constraints at the Russian Far North). These costs are much higher since the crude oil at the Vostochno-Perevalnoye oilfield is much cheaper and no transportation costs are involved since it is available locally. Therefore the costs substituted by the project are much higher in other cases than in the Vostochno-Perevalnoye case and the owners of these projects must have had much more financial incentives to implement the respective projects than the owner of the Vostochno-Perevalnoye project. Their additional baseline costs can be treated as reasons to presume that the financial conditions of the above group of projects must have differed from those of the Vostochno-Perevalnoye project. These differences in the project baseline costs clearly demonstrate the better appropriateness of the financial conditions of these projects for the owners. In case of Vostochno-Perevalnoye , the situation is different, with the Project Owner actively searching to substitute the power from the power trains that is considerably cheaper than the one generated by small-size diesel generating stations. This difference confirms the additionality of the Vostochno-Perevalnoye project .

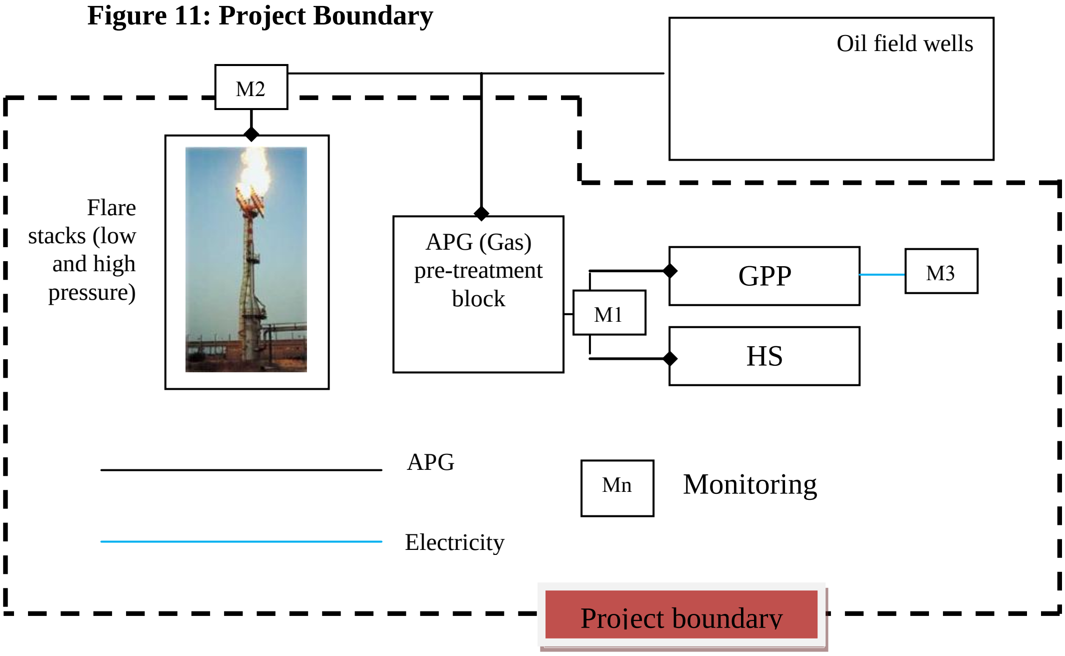
Summarizing the additionality considerations, it should be repeated that in the Project scenario, electric power (heat) for the local needs of the Vostochno-Perevalnoye oil field would be provided by gas-fired power plant (heating station). APG flaring at the Vostochno-Perevalnoye oil field would be considerably reduced. The new GPP combustion process is much more environmentally friendly than flaring and reduces the methane emissions into the air. As shown by the economic efficiency analysis, the Project itself is not the most attractive option for the Project Owner from the financial point of view; some additional financial resources within the Project is available within the perspective of respective incomes from ERU sales within the Project (that was considered at the business planning stage of the Project). Additional effect of the Project is the raise in energy efficiency, resulting in extra emissions reductions, due to substitution of the powertrains by more efficient GPPs. Therefore, it may be stated that the Project corresponds to the additionality requirements, since it is definitely not a part of the baseline scenario and reduces the GHG emissions below those that would have occurred in the absence of the project.

B.3. Description of how the definition of the project boundary is applied to the project:

The project boundary encompasses the following Project components (see figure 11):
- GPPs including auxiliary facilities such as the electrical cables, etc.
- Heating station
- Local grid (low voltage) - distribution system, transforming station.
- flare stacks (high and low pressure) at the Vostochno-Perevalnoye booster pumping stations;
- The APG treatment plant (providing fuel-Gas) and the emergency generator.
- Equipment for APG delivery to GPP (gas pipeline and pumping stations)
- Complex of metering equipment;

All components are directly under control Project owner (operator). Access to metering equipment (including certification, exploitation and calibration) is enjoyed solely by the Operator with the exception for the relevant state authorities.

Figure 11: Project Boundary



Emissions sources included into the Project boundary.

	Sources	Gas	Included	Justification/ Explanation
Baseline	Flaring of associated gas	CO_2	Yes	Main source of emissions in the baseline within any APG utilization project
		CH_4	Yes	Source of emissions in the baseline
		N_2O	No	Assumed negligible
	Consumption of oil by the power trains equal to for power & heat generation in the projected volumes	CO_2	Yes	Source of emissions in the baseline
		CH_4	No	Assumed negligible due to negligible amounts
		N_2O	No	Assumed negligible due to negligible amounts

	Sources	Gas	Included	Justification/ Explanation
Project activity	Emissions from recovered APG combustion within power generation at the GPP and heat generation at HS	CO_2	No	Main source of emissions in the project scenario within any power & heat generation APG utilization project
		CH_4	No	Assumed negligible due to negligible volumes
		N_2O	No	Assumed negligible due to negligible volumes

B.4. Further baseline information, including the date of baseline setting and the name(s) of the person(s) / entity(ies) setting the baseline:

Date of the baseline study setting 01/09/2008- 21/11/2008
Name of person(s)/entities determining the baseline:
LLC «Sigma International»
Moscow, Russian Federation
Tel. +7 (495) 7753232
Fax +7 (495) 7753232
e-mail: sigma@effort.ru

LLC «Sigma International» is not Project participant

The baseline was determined under the guidance of approved methodology CDM AM 0009

SECTION C. Duration of the project / crediting period

C.1. Starting date of the project:

September 25, 2003

C.2. Expected operational lifetime of the project:

20 years (240 months) since January 1, 2008

C.3. Length of the crediting period:

5 years (60 months) starting on January 1, 2008.

SECTION D. Monitoring plan

D.1. Description of monitoring plan chosen:

The Project will contribute to sustainable development of the host country by promoting the utilization of a wasted energy resource and will achieve three goals:

- Reducing CH_4 emissions due to more complete APG combustion in gas engines (and boilers) relative to APG flaring;
- Substitution of power generation from the powertrains to power from GPP with more efficient engine and reduced GHG emissions.

At present, no approved CDM monitoring methodology AM0009 that would allow estimating CH_4 emissions mitigation from APG flaring reduction projects is available. On the other hand, the "Methodology of calculation of emissions of hazardous substances into the atmosphere due to the flaring of the associated petroleum gas at flaring stacks" developed by the Saint-Petersburg Scientific Research Institute for Protection of Atmosphere and endorsed by State Committee for Environmental Protection (GosKomEcologiya) is designed for practical usage when estimating such emissions during APG flaring. This methodology is widely used by Russian oil and gas sector in calculations of hazardous atmospheric emissions.

Therefore, modalities relating to CH_4 emission reductions estimation contained in the "NII Atmosphere" methodology are used in the monitoring plan of this Project.

Data/Parameter	Gen
Data unit	MWh
Description	Electricity supply to consumers at Vostochno-Perevalnoye oil-field on voltage 6 kV, and electricity supplied for self consumption 0,4 kV.
Time of determination/monitoring	Monthly
Source of data (to be) used	Electric meters
Value of data applied (for ex ante calculations/determination)	34080 MWh
Justification of the choice of data or description of the measurement methods and procedures to be applied	Electric meters are installed at the 6 kV (0,4 kV) in-door switch gears, data will be archived electronically and in monitoring workbook.
QA/QC procedures (to be) applied	**QA**: measurements from the electricity meters are screened on monitors at the operator's desk; readings are taken by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration of the metering device by the regional representatives of the State Office for Metrology and Standardization

Any comment	-
Data/Parameter	Heat
Data unit	Gcal
Description	Heat delivering to local consumers
Time of determination/monitoring	Monthly
Source of data (to be) used	-
Value of data applied (for ex ante calculations/determination)	8940 Gcal
Justification of the choice of data or description of the measurement methods and procedures to be applied	Estimations based on actual gas flow to HS and existing gas consumption per 1 Gcal of heat (0,155 tons of fuel equivalent, 92% efficiency, 10724 (LVH of APG) /7000 (fuel equivalent) = 1,532 coefficient. 0,155/1,532 = 0,101 tn/Gcal
QA/QC procedures (to be) applied	**QA**: measurements from the flow-meters are screened on monitors at the operator's desk; data is fixed by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration of metering device by the regional representatives of the State Office for Metrology and Standardization
Any comment	-
Data/Parameter	EmGen
Data unit	MWh
Description	Generation on emergency diesel generator that will lead to additional emissions based on diesel combustion
Time of determination/monitoring	Monthly
Source of data (to be) used	Electric meters
Value of data applied (for ex ante calculations/determination)	0 MWh
Justification of the choice of data or description of the measurement methods and procedures to be applied	Electric meters installed at the 6 kV switch gears, data will be archived electronically and in monitoring workbook.
QA/QC procedures (to be) applied	**QA**: measurements from the electricity meters are screened on monitors at the operator's desk; readings are taken by the trained staff according to the

	requirements of the technical specifications; **QC**: periodic calibration of the metering device by the regional representatives of the State Office for Metrology and Standardization
Any comment	In a case of emergency situation on GPP, diesel generator provides electricity for the most important needs.
Data/Parameter	Vi
Data unit	%
Description	Composition of APG measured at point M1, after pretreatment, during the period *y*
Time of determination/monitoring	Twelve times a year by authorized company - GUP "IPTER"
Source of data (to be) used	Measurement provided by authorized company
Value of data applied (for ex ante calculations/determination)	Vi shown below Table 11.
Justification of the choice of data or description of the measurement methods and procedures to be applied	Authorized company on its chromatograph, at exit from gas pre-treatment block. Annual figures will be the APG volume weighted averages of twelve-times a year figures.
QA/QC procedures (to be) applied	**QA**: measurements from the chromatograph taken twelve times a year; data recorded by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration of the chromatograph by the regional representatives of the State Office for Metrology and Standardization
Any comment	M APG and density calculating on the base of available APG composition.
Data/Parameter	$V_{F,y}$
Data unit	Nm^3
Description	Volume of the total recovered gas measured at point M1, after pretreatment, during the period *y*
Time of determination/monitoring	On-line
Source of data (to be) used	Flow-meters with corrector
Value of data applied (for ex ante calculations/determination)	9676000 nm^3
Justification of the choice of	Flow-metering equipment installed at the exit from gas pre-treatment block

data or description of the measurement methods and procedures to be applied	measures volumes of APG automatically, archived electronically and in monitoring workbook.
QA/QC procedures (to be) applied	**QA**: measurements from the flow meters are screened on monitors at the operator's desk; readings are taken by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration of the meters by the regional representatives of State Office for Metrology and Standardization
Any comment	-

D.1.1. Option 1 - Monitoring of the emissions in the project scenario and the baseline scenario:

D.1.1.1. Data to be collected in order to monitor emissions from the project, and how these data will be archived:

ID number	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

Not applicable as the data was indicated in D.1.

D.1.1.2. Description of formulae used to estimate project emissions (for each gas, source etc.; emissions in units of CO_2 equivalent):

The equations used to calculate Project emissions are summarized in Table 10 below.
The project uses the approach from the previously approved CDM methodology AM0009 version 2 and assumes full oxidization.

$PE_{,y} = (Vy*Py) * W_{carbon,A,y} *44/12$

where:
PE,y - the baseline emissions during the period y in tons of CO2 equivalents.
Vy - volume of gas recovered from the oil field during the period *y*, explicated in (000) ncm.

Py - density of APG, kg/ncm.
Wcarbon,A,y - the average content of carbon in the gas recovered during the period y.
The methane content in the gas W*carbon,A,y* is determined from Table 11, 1.

Table 10: Project emissions calculation equations

1- **Determination of Full-Time Equivalent engines (furnaces) in operation mode**

PE1	1	2	3	4	5	6=1*2*3*4/5
	Mass amount of APG flared	Carbon mass fraction in APG		Molecular mass of CO2	Molecular mass of C	Total CO2 emissions project
	M APG	σ c_APG	*scalar*	*μ CO2*	*μ C*	*ECO2_combustion project*
Units	T	% mass		kgCO2/mole	kgC/mole	tCO2
GPP	9839,3	76,34947616	0,01	44	12	27545,0
HS	906,0	76,34947616	0,01	44	12	2536,3
	10745,3				Total	30081,3

2- Emissions from emergency diesel generator

	1	2 IPCC Factor	3=1*2
	Electricity by emergency diesel generator	Emissions factor for electricity by diesel generator	Total emissions _ emergency diesel generator
PE2	*Emgen_fuel*	*Diesel fuel EF*	*Emgn_CO2*
Units	MWh	tCO2/MW	tCO2
	0	0,2626	0

3- Total Project emissions

PE3	1 from PE1	2 from PE2	3=2+1

	Total emissions from APG _ project	Total emissions _ emergency diesel generator	Total emissions project
	ECO2e_APG_project	*Emgn_CO2*	*ECO2e_total_project*
Units	tCO2e	tCO2	tCO2
	30081	0	30081

Thus, total project emissions 30,081 tCO2e per year.

As explained in Section B.2, emissions based on leakages and/or accidents are likely to be greater in the baseline delivery of APG to the flare than they will be in the operation of the new GPP and HS. Therefore, potential leaks and accident emissions in the Project scenario have been ignored to assure that the emission reduction estimates are based on conservative assumptions.

D.1.1.3. Relevant data necessary for determining the baseline of anthropogenic emissions of greenhouse gases by sources within the project boundary, and how such data will be collected and archived:

ID number	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

Not applicable as the data was indicated in D.1.

D.1.1.4. Description of formulae used to estimate baseline emissions (for each gas, source etc.; emissions in units of CO_2 equivalent):

Baseline emissions at the Vostochno-Perevalnoye flare are calculated using equations *BE2* through *BE6* below in combination with *BE1* as shown in Table 11. Color coding distinguishes inputs which will be monitored each year (yellow); inputs that will be stipulated upfront as constants (green) and calculated values (blue).

Columns (6) in equation *BE4* and column (1) in equation *BE3* are parameters that are specified in the methodology of NII Atmosphere for calculating emissions from flaring of APG in Russia. The factors shown assume that the Vostochno-Perevalnoye flare will continue to operate in black-firing mode. The monitoring plan addresses the photo evidence that will support this assumption going forward. The key input parameters for future years will be the volume of APG used by the GPP and HS (column (1) in equation *BE5)*, the density of that APG and the volumetric composition of the APG.

Table 11: Equations for local baseline emissions at the APG flare

1- Calculation of mass fraction of APG components

BE1		1	2	3	4	5	6	7	8=1*5/100	9=6*7	10=7*3/ $miCH_4$
Unit	Index	*Vi*	*Pi*	*Mi*	*µi*	*Ki*	*σc-i*	*σi*	*k APG*	*σc_APG*	*σ CH4*
	Component	Volume fraction, weighted average of monitored monthly data	Density of hydrocarbons and elements	Molecular mass of components	Molecular mass of icomponent in APG	Adiabatic index of icomponent of APG	mass content of carbon of icomponent in APG	Molar ratio	Adiabatic index of APG	Mass fraction of Carbon in APG	Hydrocarbons in CH4 equivalent
		%	kg/m3	kg/mole	kg/mole		% mass	%		% mass	%
	CH_4	76,00	0,716	16,043	12,19268	1,31	74,87	0,49000	0,9956	36,6862	0,489999
	C_2H_6	4,89	1,342	30,07	1,470423	1,21	79,98	0,05909	0,0592	4,7262	0,110759
	C_3H_8	7,25	1,969	44,097	3,197033	1,13	81,71	0,12854	0,0819	10,5033	0,353326
	C_4H_{10}	3,80	2,595	58,124	2,208712	1,1	82,66	0,08880	0,0418	7,3398	0,321706
	C_5H_{12}	1,68	3,221	72,151	1,212137	1,08	83,24	0,04873	0,0181	4,0560	0,219142
	C_6H_{14}	1,62	3,842	86,066	1,394269	1,07	83,73	0,05605	0,0173	4,6927	0,300668
	C_7H_{16}	1,49	4,468	100,08	1,491192	1,06	84,01	0,05995	0,0158	5,0361	0,373964
	C_8H_{18}	0,72	5,1	114,23	0,822456	1,05	84,21	0,03307	0,0076	2,7844	0,235432
	CO_2	1,08	1,977	44,011	0,475319	1,3	27,29	0,01923	0,0140	0,5247	2,404993
	N_2	1,47	1,251	28,016	0,411835	1,04	100	0,01656	0,0153	1,6559	
	Total	100,00			24,87606				1,2667	76,3495	
		Density		1,11053							

2- Quantity of carbon atoms in molecular formula of APG

BE2	1	2	3	4	5=(1*3/4)*2

	Mass fraction of Carbon in APG	Molecular mass of APG		Molecular mass of carbon	Quan. Of carbon atoms in molecular APG
	σ c_APG	*µ APG*		*µ c*	*Kc*
Units	% mass	kg/mole	Scalar	kg/mole	carbon atoms
	76,3495	24,876056	0,01	12	1,583

3- CH_4 emission factor for APG flaring

	1	2	3=1*2
	Ku/f (bf)	*σ CH_4*	*e CH4_baseline*
BE3	Under firing coefficient	Total hydrocarbons in CH_4 equivalent	CH4 emission factor _ baseline
units	Scalar	% mass	Kg CH4/kg APG
	0,035	2,404993	0,0842

4 - CO_2 emission factor for APG flaring

BE4	1	2	3	4	5	6	7	8=2/3	9=4/5	10=6/7	11=1*(8-9-10)
Units	Molecular mass of CO2	Qu of carbons in APG formula	Molecular mass of APG	CH4 emission factor _ baseline	Molecular mass of CH4	CO emission factor _ baseline (black firing)	Molecular mass of CO	C emission factor _ baseline	Molecular mass of CH4	Molecular mass of CO in APG	CO2 emission factor
	µ CO2	*Kc*	*µ APG*	*e CH4_baseline*	*µ CH_4*	*e CO_baseline*	*µ CO*	e C_baseline			*e CO2*
	kgCO2/ mole	Carbon atoms	kg APG/mole	Kg CH4/kg APG	Kg CH4/kg mole	Kg CO/kg APG	kgCO/mole		Kg CH4/mole APG	Kg CO/mole APG	Kg CO2/kg APG
	44	1,583	24,87606	0,0842	16	0,25	28	0,0636	0,0053	0,0089	2,1751

5- Mass amount of APG flared

BE5	1	2	3=1*2

	Annual volumetric flow of APG to be flared	Density of APG	Mass amount of APG flared
	V APG	*ρ APG*	*M APG*
Units	ncm (000)	kg/ncm	t
GPP	8860	1,110534	9839,3
HS	816	1,110534	906,0
Total	9676	1,110534	10745,3

6- Total emissions from APG flare

BE6	1	2	3	4	5=1*2	6=1*3*4	7=5+6
	Mass amount of APG flared	CO2 emission factor_baseline	CH4 emission factor_baseline	CH4 global warming potential	CO2 emissions from complete burning	Total CH4 emissions in terms of tCO2e	Total CO2 emissions from APG flaring
	M APG	*e CO2_baseline*	*e CH4_baseline*	*GWP CH4*	*E_{CO2} complete baseline*	*E_{CH_4} baseline*	*E_{CO2e} flaring baseline*
Units	T	Kg CO2/kg APG	Kg CH4/kg APG	Scalar	tCO2e	tCO2	tCO2
GPP	9839,3	2,1751	0,0842	21	21402,0	17392,7	38794,6
HS	906,0	2,1751	0,0842	21	1970,7	1601,5	3572,2
Total	10745,3	2,1751	0,0842	21	23372,6	18994,2	42366,8
2008	3366	2,1751	0,0842	21	7321	5949,7	13270,9

The second major component of baseline emissions is the GHG to be released by powertrains in course of generating power equal to the power amount to be generated by the GPP within the Project. Table 12 shows equation *BE7*, *BE8*, *BE9*, that used to calculate baseline emissions from powertrains.

Total power deliveries to consumers will be metered and confirmed by data from ACS, meter equipment reflecting actual load, forming current regime of GPP work. Algorithm of ACS management is:
Growth of loads (consumption) → decrease of voltage → additional (power) engines started → increasing generation→ increasing gas consumption.
The same principle of regulation was confirmed in ACS of HS.

So in comparison with GPP working with external network, GPP on Vostochno-Perevalnoye oil field actual consumption and actual delivery have more objective data, suitable for monitoring plan. All losses in local grid will be calculated as the difference between power generated and derivative of installed equipment capacity and hours of operation.

Factors of unified fuel equivalent use for generation (tuf/MWh) were taken into account as stable parameters within due to 5 years of operating the powertrains. For monitoring plan it was considered appropriate to use determined by auditor ("Energoperspektiva" Ltd.) data from well Group #1 (NGDU "RITEKNadymneft"), exploited powertrains until GPP commissioning.

Modification (theoretical) of quality of fuel, that can additionally reduce emissions, compensates by decreasing efficiency of consuming equipment due to their physical amortization, and accordingly growth of energy consumption (and fuel reduction in frameworks of project line)

Heat consumption *(BE7) is* equal to existing in settlement. All available losses in heating networks (Project line), and in electric devices (Baseline) were also included. Detailed description of losses will require the due metrological work.

The Table 12 (A-D) combines local and powertrains fuel consumption and emissions to calculate the total annual *ex-ante* estimate of baseline emissions.

Table 12: Baseline powertrains emission equations (A) - heat generation, (B) fuel consumption due to electricity generation, and total baseline emission (C) (D)

(A) Baseline heat generation (HS)

BE7	1	2	3	4	5	6
	Installed heat capacity	Annual heat delivery	Electricity networks losses	Gross heat generation	Consumption tons equivalent fuel per MW	Fuel consumption (heat)
	Net cap / exchanger	*Heatdel _ local*	*Net _ losses*	*Gross _ heatdel*	*EF_CM*	*Fuel _ heat*
Units	MW	MWh	%	MWh	tuf/MWh	tuf
	1,89	10395	9	11423	0,596	6808

(B) Electricity generation by GPP

BE8	1	2	3=1*2
	Electricity (net) generation	Consumption tons equivalent fuel per MW	Fuel consumption (electricity)
	Elec _ gen	*EF_CM*	*Fuel _ elec*
Units	MWh	tuf/MWh	Tuf

	34079	0,596	20311

(C) CO2 emissions from power trains

BE9	1 (BE7)	2(BE8)	3=1+2	4	5=3*4	6	7=6*5*44/12/1000
	Fuel consumption (heat)	Fuel consumption (electricity)	Total fuel consumption	Energy per ton of unified fuel	Total energy consumption	Default carbon content	CO2 emissions trains
	Fuel _ heat	*Fuel _ elec*	*Fuel _ total*	*Energy _ coef*	*Total _ energy*	*Carbon factor*	*trains_CO2*
Units	Tuf	Tuf	Tuf	MJ/tuf	MJ	kg/GJ	tCO_2
	6808	20311	27119	29300	794594	20	58270,2
2008	6808	5078	11886	29300	348258	20	25538,9

(D) Total baseline emissions

BE10	1	2	3=1+2
	Total CO2 emissions from APG flaring	CO2 emissions trains	Total baseline emissions
	E CO2e flaring baseline	*trains_CO2*	*ECO2e_total_baseline*
Units	tCO2	tCO2	tCO2
	42367	58270	**100637**

1. For purposes of present sector of PDD emission factor CH_4 and N_2O was not defined due to it's extremely inferiority (less 1% from total emissions)
2. Default carbon content factor (rate for crude oil) was considered, as the most corresponding to specific of oil-field exploitation. (According to Table 1-3 of 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, "Energy", Chapter 1)

D. 1.2. Option 2 - Direct monitoring of emission reductions from the project (values should be consistent with those in section E.):

Option is not used.

D.1.2.1. Data to be collected in order to monitor emission reductions from the project, and how these data will be archived:								
ID number	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e),	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

Not applicable as the data was indicated in D.1.

D.1.2.2. Description of formulae used to calculate emission reductions from the project (for each gas, source etc.; emissions/emission reductions in units of CO_2 equivalent):

Not used

D.1.3. Treatment of leakage in the monitoring plan:

No leakages were identified that correspond to net changes of emissions which occur outside the project boundary and are measurable and attributable to the Project activity. (Gas pipeline from oil field to gas pre-treatment block) is about 1 km, and has doubled insulation). Emissions related to the supply of fuel for the emergency diesel unit and the emissions from installing the new equipment will not be significant. Much greater emissions could be associated with delivery of gas to grid power plants situated in region (Surgut), which does not occur in the Project that presumes local on-site power generation and consumption. Therefore, the exclusion of leakages from the Project will assure conservatism in the estimation of emission reductions within the Project

D.1.3.1. If applicable, please describe the data and information that will be collected in order to monitor leakage effects of the project:								
ID number	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e),	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

Not applicable as the data was indicated in D.1.

D.1.3.2. Description of formulae used to estimate leakage (for each gas, source etc.; emissions in units of CO_2 equivalent):

No formulae used to estimate leakage (please see Section D.1.3).

D.1.4. Description of formulae used to estimate emission reductions for the project (for each gas, source etc.; emissions/emission reductions in units of CO_2 equivalent):

Ex ante estimates of the total annual emission reductions for the Project have been derived in equation *ER1* as a difference between the total baseline emissions estimated by equation *BE6* in Table 11 and *BE9* in Table 12 total Project emissions estimated by equation *PE3* in Table 10.

Table 13: Annual emission reductions

ER1	1 (from BE6+BE9)	2 (from PE3)	3=1-2
	Total baseline emissions	Total emissions project	Total emissions reduction
	ECO2e_total_baseline	*ECO2e_total_project*	*ER CO2e_total*
Units	tCO2	tCO2	tCO2e
	100637	30081	70556

D.1.5. Where applicable, in accordance with procedures as required by the host Party, information on the collection and archiving of information on the environmental impacts of the project:

A four level system for the monitoring of environmental impacts has been established at the GPP. Data from HS also reflect in monitoring plan of GPP. This system allows monitoring, reporting and controlling of the maximum concentrations of the hazardous substances emissions such as CH_4, NO_x, and CO:

1. First, the gas contamination sensors that monitor CH_4 concentrations relative to maximum permissible emissions (MPE) limits are installed at the APG treatment plant and at condensate collection tanks.
2. Second, the generating units at the power hall (GPP) are equipped with the *LENOX* controlling system, which automatically monitors CH_4 concentrations in the engines.
3. Third, the mobile mechanized plant, *TESTO*, monitors concentration of the hazardous waste in the exhaust gases at any desired measuring point (engine, power hall, furnaces, etc. in GPP and heating station). The emissions measurement may be taken in any required place. Once the data is measured, the shift operator inputs it in his log book.
4. Fourth, the shift operator is periodically on a beat monitoring the situation with gas emissions.

In case of exceeding the established MPE maximum limits, the signals from sensors will come in GPP's automated control system (ACS) that will adjust working parameters of the equipment to an optimized safe operation level. The shift operator inputs the measurements (in case of exceeding the maximum limits) in the log book. All shift log books will be numbered, tied together and archived for 5 years.

In frameworks of National Environmental Regulation of host party – maximum permitted emissions (MPE) determined according to GOST 17.2.3.02-78 (regulation standards of harmful substance's emissions for Industry). GOST's using during estimation of environmental impact in frames of project documentation, simultaneously with established by Ministry of Health USSR in 1978 maximum permitted concentrations (MPC).

D.3. Quality control (QC) and quality assurance (QA) procedures undertaken for data monitored:		
Data *(Indicate table and ID number)*	Uncertainty level of data (High/Medium/Low)	Explain QA/QC procedures planned for these data, or why such procedures are not necessary.
1. VAPG	Medium (in accuracy of measurements 5%)	**QA**: measurements from the flow meters is screened on monitors at the operator's desk; readings are taken by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration of the meters by the regional representatives of State Office for Metrology and Standardization
2.V%	Low (Instrumental error 0,5%)	**QA**: measurements from the chromatograph taken twelve times a year; data recorded by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration of the chromatograph by the regional representatives of the State Office for Metrology and Standardization
3. ElecDel 6 kV	Low (Instrumental error 0,2%)	**QA**: measurements from the electricity meters is screened on monitors at the operator's desk; readings are taken by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration of the meters by the regional representatives of the State Office for Metrology and Standardization
4. ElecDel 0,4 kV	Low (Instrumental error 0,2%)	**QA**: measurements from the electricity meters is screened on monitors at the operator's desk; readings are taken by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration by the regional representatives of the State Office for Metrology and Standardization

5. EF_{CO2}_diesel _fuel	Low	**QA:** the CO_2 emissions factor of the diesel fuel is taken from the Appendix B of the simplified modalities and procedures for small CDM project activities (IPCC factor); **QC:** periodic (once a year) check of this data

D.3. Please describe the operational and management structure that the project operator will apply in implementing the monitoring plan:

The Project's operational and management structure will be totally in compliance with that of existing at the GPP and HS. Majority of variables are monitored under normal day-to-day routine practice. Data on GPP performance indicators, including APG deliveries and electricity supplied to RITEK and also self consumption. Based on that, the monitoring structure will be as follows:

At the GPP level, the shift operators will be responsible, on day-to-day basis for monitoring the variables indicated above in subchapter D.1.1.2. and D.1.1.4., including taking the readings from electricity meters, APG flow meters, chromatograph and the fuel tank contents and deliveries. The monitoring and reporting of most of these data (volume, capacity and electricity flows) has been already adopted under the routine operation regime of the GPP. Composition and density of APG, determined two times a year (in winter and in summer), by authorized organization. Emission reductions will be automatically determined, as a Microsoft Excel program will make the necessary calculations with the use of formulas described in the subchapter D.1.1.2 and D.1.1.4. the tables provided in the Monitoring Workbook. All this information will be documented and stored in paper and electronically with the operator. The necessary instruction with regard to monitoring of emission reductions will be provided to GPP operators.

Every month, the data used to calculate emission reductions received will be summed up and be reported to the GPP's chief manager, who will transfer them via the e-mail to the head office of RITEK in Moscow. The manager of RITEK responsible for the Project will provide general supervision of the technical performance of GPP including verification of data storage. To provide the verification of emission reductions generated by the Project, the archiving of data will be extended until 2014.

D.4. Name of person(s)/entity(ies) establishing the monitoring plan:

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Fax +7 (495) 7753232
e-mail: sigma@effort.ru

SECTION E. Estimation of greenhouse gas emission reductions

E.1. Estimated project emissions:

Ex-ante Project emission estimates have been developed on a basis of actual GPP and Heating station performance data available in 2008, added with necessary information on gas composition from April and June of 2007. HS was commissioning in January 2008. GPP reached projected power capacity in October 2008 and APG utilization level in compliance with the targets set in present PDD. Further operation of Vostochno-Perevalnoye GPP and heating station has been characterized by similar parameters without any significant deviation.
Therefore, *ex-ante* estimates provided in this section are assumed to be representative for each year of Project implementation (although the actual figures will vary based on ex post data).
Ex-ante Project emission estimates have been developed using the equations shown in table 10 (see Section D.1.1.2.). Table below provides the *ex-ante* illustrative calculation of annual Project emission from APG combustion excluding possible emissions from emergency diesel generator at 30,532 tCO_2e.

Table 14: Project emissions from APG combustion at the GPP and at HS

APG combustion in Project gas power plant (GPP)			
Emissions from GPP calculation			
M APG	Mass amount of APG flared	T	9839,3
σ c_APG	Carbon mass fraction in APG	% mass	76,3494
μ CO2	Molecular mass of CO2	Kg CO2/mole	44
μ C	Molecular mass of carbon	Kg C/mole	12
ECO2_combustion project	GPP CO_2 emissions project	tCO_2	27545,0
APG combustion in Project heating station (HS)			
Emissions from HS calculation			
M APG	Mass amount of APG flared	T	906
σ c_APG	Carbon mass fraction in APG	% mass	76,3494
μ CO2	Molecular mass of CO2	Kg CO2/mole	44
μ C	Molecular mass of carbon	Kg C/mole	12
ECO2_combustion project	HS CO_2 emissions project	tCO_2	2536,3
Total APG combustion in GPP and HS			
CO2_project	Total Project emissions	tCO2e	30081,3

The *ex-ante* estimates of emissions from the emergency diesel generator are estimated in Table 15.

Table 15: Project emissions from emergency generator

Emgen_fuel	Electricity by emergency diesel generator	MWh	0
Diesel fuel EF	Emissions factor for electricity by diesel generator	tCO2/MWh	0,2626
Emgn_CO2	Total emissions _ emergency diesel generator	tCO2	0

Total Project emissions from all sources are then summarized for all relevant years in Table 16. *Ex-ante* estimates for 2008 through 2012 are equal to the *ex-ante* illustrative estimates shown.

Table 16: Total project emissions by year

year	APG combustion engines	Carbon mass fraction in APG	Molecular mass of CO2	Molecular mass of C	Diesel generator emissions	Total emissions project
		σ c_APG	*μ CO2*	*μ C*	*Emgn_CO2*	*ECO2e_total project*
	tAPG	% mass	kgCO2/mole	kgC/mole	tCO2	tCO_2e
Ex-ante illustration	10745	76,349	44	12	0	30081
2008	3365	76,349	44	12	0	9423
2009	10745	76,349	44	12	0	30081
2010	10745	76,349	44	12	0	30081
2011	10745	76,349	44	12	0	30081
2012	10745	76,349	44	12	0	30081

E.2. Estimated leakage:

Not identified.

E.3. The sum of E.1. and E.2.:

Since quantified leakage estimates have been excluded, the total Project emissions are estimated as 25,949 tCO_2e per year and 129,747 tCO_2e for the period 2008-2012 (see table 16).

E.4. Estimated baseline emissions:

The estimations of the baseline emissions apply the equations demonstrated in the table 11 and 12. These estimations and are based on the measurements of the APG characteristics, available data on the Vostochno-Perevalnoye flare stack for 2007-2008 and on the available data (including oil composition) on powertrain operation. Future characteristics of the Vostochno-Perevalnoye APG flare and of the power consumption are not expected to change significantly (although the actual figures will vary based on ex post data). Therefore, *ex-ante* estimates provided in this section are assumed to be reasonably representative for each year of Project implementation.

The baseline emissions include 2 main sources:
- Annual emissions due to flaring of the amount of APG equal to the annual APG to be utilized within the Project by GPP and hating station (see table 17);
- Substitution of power generated by powertrains combusting crude-oil with low efficiency and high emissions factor by GPP (partly HS).

Table 17: Local baseline emissions from flaring APG to be used within the Project

Step 1. Determining mass amount of APG flared, kg	Ex-ante illustration

Index	Parameter	Units	Value
V APG	Annual volumetric flow of APG to be flared	ncm (000)	9676
ρ APG	Density of APG	kg/ncm	1,110
M APG	Mass amount of APG flared	T	10745,3
Step 2. Calculation of APG molecular mass			
Index	Parameter	Units	Value
μ APG	Molecular mass of APG	kg APG/mole	24,87606
Step 3. Determining physical-chemical parameters			
Index	Parameter	Units	Value
k APG	Adiabatic index of APG	-	1,27
σc_APG	Mass fraction of carbon in APG	%	76,34
Kc	Quan. Of carbon atoms in molecular APG	carbon atoms	1,583
Step 4.	Non-black flaring test: Discharge jet flow > 0,2 Sound velocity in APG flared		
Index	Parameter	Units	Value
U flow	APG`s discharge jet flow velocity	m/s	52-65
U sound	Sound velocity in APG flared	m/s	350,4
	Result of the test	52-65 m/s < 70,08 m/s	black firing
Step 5. CH4 emissions due to incomplete burning			
Index	Parameter	Units	Value
k u/f	Under-firing coefficient	-	0,035
σ CH4	CH4 mass fraction	% mass	2,404993
e CH4_baseline	CH4 emission factor_baseline	kgCH4/kgAPG	0,0842
MAPG	APG flared per year	kgAPG	10745331
E CH4_baseline	Total CH4 emissions_baseline	tCH4	904
		tCO2e	18994
Step 6. Total CO2 emissions from APG flaring			
Index	Parameter	Units	Value
μ CO2	Molecular mass of CO2	kg CO2/mole	44
Kc	Quan. of carbon atoms in molecular APG	carbon atoms	1,583
μ APG	Molecular mass of APG	kg/mole	24,876
e CH4_baseline	CH4 emission factor baseline	kgCH4/kgAPG	0,0842
μ CH4	Molecular mass of CH4	Kg CH4/kg mole	16
e CO_baseline	CO emission factor_baseline	kgCO/kgAPG	0,25
μ CO	Molecular mass of CO	kgCO2/mole	28
e CO2	CO2 emission factor_baseline	kgCO2/kgAPG	2,1751
M APG	APG flared per year	kgAPG	10745331
E CO2 complete baseline	CO2 emissions from complete burning	tCO2e	23373
ECO2e_flaring_baseline	Total CO2e emissions from APG flaring	tCO2e	42367

The NII "Atmosphere" methodology has been applied in this analysis as detailed above (see table 11). The most critical inputs to these calculations are the parameters defining the composition of the APG that is used in the GPP (HS). Step 4 of the calculation of baseline emissions from APG flaring also provides the calculation that is used to determine that the Vostochno-Perevalnoye flare is operating in black-firing mode.

The usual historic mode of operation of this flare which is more than 8 years old has been black-firing mode and RITEK has little, if any, incentive to reconstruct the flare or change its operation in any fundamental way. The Project sponsors do not have guaranteed access to the specific data that would be required to calculate this test at routine intervals in the future. However, it is believed that any change sufficient to move away from black-firing mode would necessarily involve substantial reconstruction of the flare that would be clearly visible. Thus, photo documentation that the flare has not been fundamentally rebuilt is proposed as the appropriate monitoring method to establish that the black-firing parameters are appropriate for use in future calculations. If significant observable reconstruction occurs, the Project sponsor will request the data needed to recalculate the black-firing test.

Local baseline emissions from the APG flare are estimated to be 42,367 tCO2e per year.

In the baseline scenario, RITEK would continue to consume 34,08 MWh p/a of electricity from the powertrains. This amount of electricity is supplied by the GPP and the emergency diesel generator in the Project scenario. Heat (10395 MWh p/a) formerly provided with electric heating devices is supplied in the Project Scenario by heating station TKU-1890. The *ex-ante* estimates of the annual baseline powertrains emissions related to this supply are equal to 58,270 tCO_2e (see table 12A-C). Monthly and annual power deliveries to RITEK will be monitored due to confirmed metering devices on feeders. The powertrains fuel use factor is equal to 0,596 t of equivalent fuel/MWh, according to the data based on five year record of operating experience.

Local and powertrains baseline emissions taken together as shown in Table 18 to make the total annual *ex-ante* estimate of 100,637 tCO2e. The *ex-ante* estimates for years 2008 through 2012 are assumed to be identical to the illustrative case shown, thus the total baseline emissions for the period 2008-2012 are estimated at 441,358 tCO_2e.

Table 18: Total baseline emissions

Year	Total CO2e emissions from APG flaring	Total CO2 emissions from powertrains	Total baseline emissions
	ECO2e_flaring_baseline	*ECO2_total*	*E CO2e_total_baseline*
	tCO2e	tCO2e	tCO2e
ex-Ante Illustration	42367	58270	100637
2008	13271	25539	38810
2009	42367	58270	100637
2010	42367	58270	100637
2011	42367	58270	100637
2012	42367	58270	100637
Total for 2008-2012	182738	258620	441358

E.5. Difference between E.4. and E.3. representing the emission reductions of the project:

The *ex-ante* emission reduction estimate is shown in Table 19 below. *Ex*-ante estimates are the same for future years although the actual figures will vary based on *ex-post* data on the APG used, the composition and characteristics of that APG, and the electricity delivered from the GPP and heat from HS (and the emergency diesel generator). Estimated emission reductions are 62,322 tCO_2e per year and 311,610 tCO_2e for the period 2008-2012.

E.6. Table providing values obtained when applying formulae above:

The estimations for the Project emissions are provided in the tables 14, 15 and 16 in the section E.1. and the estimations for the baseline emissions are provided in the tables 17,18. As shown in the table 19, for the period 2008-2012, the total project emissions reductions due to the Project are estimated *ex-ante* at 311,610 tCO_2e as a difference between the project emissions (129,747 tCO_2e) and baseline emissions (441,358 tCO_2e).

Table 19: Ex-ante emission reduction estimates

Year	Estimated project emissions (tonnes of CO2 equivalent)	Estimated leakage (tonnes of CO2 equivalent)	Estimated baseline emissions (tonnes of CO2 equivalent)	Estimated emissions reductions (tonnes of CO2 equivalent)
2008	9422	0	38810	29388
2009	30081	0	100637	70556
2010	30081	0	100637	70556
2011	30081	0	100637	70556
2012	30081	0	100637	70556
Total (tons of CO2 equivalent)	129747	0	441358	311610

SECTION F. Environmental impacts

F.1. Documentation on the analysis of the environmental impacts of the project, including transboundary impacts, in accordance with procedures as determined by the host Party:

According to the Order of the State Committee of the Russian Federation for Environmental protection as of 15.05.2000 # 372 “On the approval of the regulations on the assessment of the impact of the planned economic and other activity on the environment of the Russian Federation” the project developers must include in the project documentation the special assessment of environmental impact.

On assignment with *RITEK*, a scientific research institute, JSC Giprotyumenneftegaz, has elaborated the environmental impact assessment (EIA) for the Project, within the Project documentation.

EIA consists of the following chapters:

- general part;
- physical-geographical characteristics of the Project site;
- land protection measures ;
- water disposal and water usage;
- waste management;
- impact on atmospheric air;
- recommendations on environmental monitoring;
- assessment of the impact on the components of the environmental system ;
    - -socio –economic impact assessment

The environmental impact assessment (EIA) documentation with regard to this Project has undergone public environmental examination. The Project including the Assessment of environmental impact has received an official approval of the local Khanty-Mansy Branch of the Russian State Expertise (granted on April 28, 2008 ., # 157-08/ХМЭ-0165/2), with attached detailed analysis of the environmental impact, confirming the basic considerations and conclusions of the Assessment of environmental impact provided by the Giprotyumenneftegaz project documentation. Upon the launching of the GPP into operation the due permission was obtained by the Project Owner from the local branch of the Russian Technical Supervisory Service (Rostechnadzor) for related emissions of substances emitted by the Project facilities.
With regard to the impact to atmospheric air, the emissions of polluting substances during Project construction and operation periods are represented in the tables 20, 21 and 22.

Table 20: Polluting emissions during operation period

Location	Source	Quantity	Polluting emissions		
			type	g/sec	tonnes/year
GPP	Gas engine flue	2	Carbon oxide, CO	11,4849	361,899
			Nitrogen dioxide, NO_2	3,06264	96,5064
			Saturated hydrocarbons C1-C5	13,7819	434,279

	pipe		Nitrogen Oxide, NO	0,49768	15,6823

Table 21: Polluting emissions from machinery during construction period (12 months)

Location	Source	Quantity	Polluting emissions		
			type	g/sec	tonnes/year
Project site	Construction machinery	15	Carbon oxide, CO	2,69869	0,67885
			Nitrogen dioxide, NO_2	0,67761	0,17802
			Kerosene	0,25929	0,07278
			Soot	0,14024	0,03937
			Sulphur dioxide	0,08410	0,02116
			Nitrogen Oxide, NO	0,11011	0,02893

Table 22: Polluting emissions from welding during construction period

Location	Source	Quantity	Polluting emissions		
			type	g/sec	tonnes/year
Project site	welding		Ferrous oxide	0,03190	0,00057
			Manganese	0,00250	0,00005
			Dust SiO2	0,00230	0,00004
			Fluorides	0,00230	0,00004
			Carbon Oxide, CO	0,03052	0,00055
			Nitrogen Oxide, NO2	0,00620	0,00011

SECTION G. Stakeholders' comments

G.1. Information on stakeholders' comments on the project, as appropriate:

This project has not been controversial since the site is within the leasehold area that RITEK has long used for oil development and the emissions from the GPP are less significant than those from the flare. No significant comments were received during the preparation of the EIA.

Annex 1

CONTACT INFORMATION ON PROJECT PARTICIPANTS

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Annex 2

BASELINE INFORMATION

Detailed baseline information was given in Sector B.

Annex 3

MONITORING PLAN

1. OVERVIEW

1.1. Objective of the monitoring plan

The objective of the monitoring plan is to ensure that the Associated Petroleum Gas Flaring Reduction Project at the Vostochno-Perevalnoye Oil Field, Western Siberia, Russia ("the Project") meets requirements for the collection, processing and auditing/verification of data to fulfill the requirements for the issuance of Emission Reduction Units (ERUs) pertaining to Article 6 of the Kyoto Protocol.

APG at the Vostochno-Perevalnoye oil field is obtained during the separation process at the booster pump station located next to the new power plant. Previously, the APG used by the Project was flared. In the Project, part of the APG (approximately 9,7 million m^3 per year) is used in the power plant with the remaining APG flared as usual in the stack of the booster pump station. Power producing for self consumption was provided by so called – powertrains PE-6M, and heat from electrical heating devices.

1.2. The Project

The project includes utilization of associated petroleum gas (APG) on modern power station with the general installed capacity 7,5 MW and on heating station with capacity 1,89 MW on Vostochno-Perevalnoye oil field (owner- OJSC "RITEK"), Surgutsky area, Khanty-Mansijsky Okrug - Yugra, Tumen oblast, Western Siberia, Russia (Figure 1a). Five Cummins QSV 91G generating units of 1.5 MW of nominal electrical capacity each are installed at the plant and three furnaces KVG 0,63 MW at heating station (HS). Power plant was designed specially for APG utilization. Generated energy (electrical and heat) ensures operation of all complex of the basic and supporting equipment on the oil wells and in well-exploiting settlement.

APG at the Vostochno-Perevalnoye oil field is obtained during the separation process at the booster pump station located next to the new power plant and heating station. The APG utilized within the Project was previously flared as shown in Figure 1. Within the Project, part of the APG (approximately 9,7 million m^3 per year) is used by the power plant and HS with the remaining APG flared as usual at the stack of the booster pump station. Power production for the needs of the project owner was initially ensured by the so called – powertrains PE-6M (mobile generating facilities consuming oil as a *basic fuel*). Heating was ensured by electric devices.

The Project will reduce CO_2 and CH_4 emissions in two ways:

- Local emissions of CO_2 and CH_4 will be reduced due to increased combustion efficiency in the gas engines compared to the Vostochno-Perevalnoye flare,
- Emissions of CO_2 from crude-oil combustion reduced on APG gas which has smaller CO_2 – emission factor.

Estimated total reductions of GHG emissions will be around 70,556 tonnes of CO_2 equivalent (tCO_2e) per year (except 2008 - 29,388 tCO_2e) and respectively 311,610 tCO_2e within the 2008-2012 crediting period.

1.3. Monitoring points

The key points to monitor the Project's input and output flows are indicated in Figure 1. The description of the monitoring points is provided in Table 1 following the diagram.

Figure 1: Monitoring points of the project

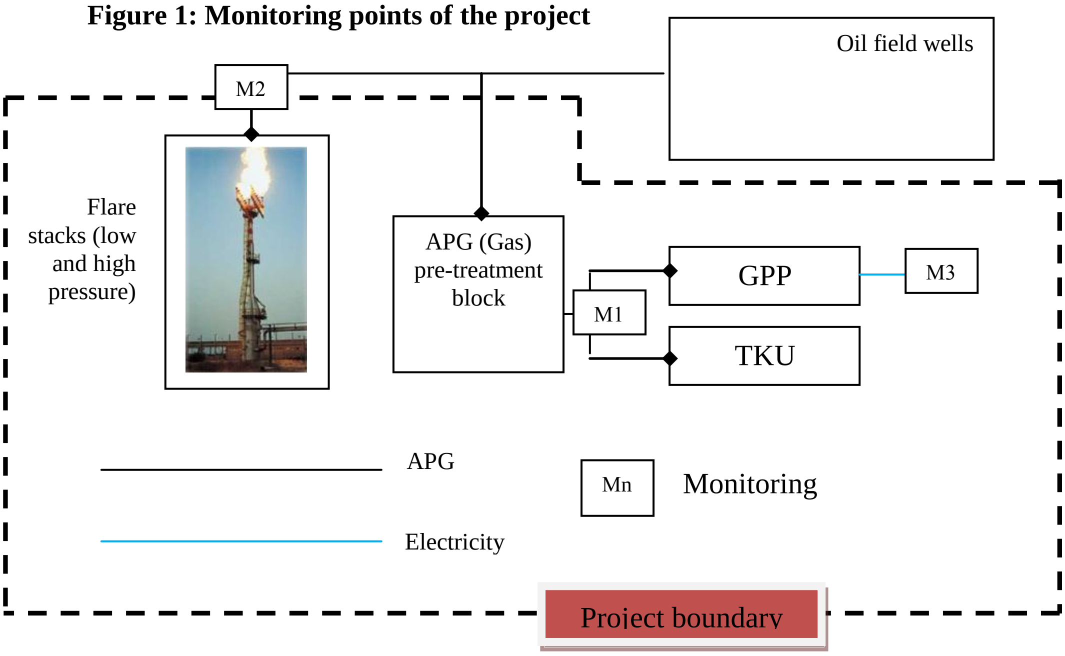

Table 1: Description of monitoring points

Monitoring Point	Location	Parameters to monitor	Quantity | year	Metering equipment
M1	Pre-treatment block (exit)	Gas volume explicated in normal cubic meters	Actual volumes (9,7 mln cubic meters for 2009)	Flowmeter
M2	Flare stack	Flaring on a stack superfluous gas volume and pressure	Actual volumes	Flowmeter,
M3	Feeders on GPP	Electricity delivery	34,1 GWh	Electricity counter SET 4TM

Project deliveries of electricity to outside consumers are monitored at the sale points which are located at the GPP’s switch gears of 6 kV and 0,4 kV accordingly, where technical metering of power output is provided. Calculation of self consumption can also be provided in accordance with present standards of electricity consumption by power stations. Such data are usually rather stable.

Heat delivery is estimating at exit from furnace.

The volume of APG delivered to GPP and its physical and chemical characteristics (such as the chemical composition and the density) are monitored at the APG treatment plant.

2. CALCULATIONS AND ASSUMPTIONS

Outline of GHG reduction calculation

The Project will contribute to sustainable development of the host country by promoting the utilization of a wasted energy resource and will achieve two goals:

- Reducing CH_4 emissions due to more complete APG combustion in gas engines relative to APG flaring in the Vostochno-Perevalnoye stack;
- Displacement of electricity generation from the powertrains and related reductions in GHG emissions.

At present, no approved CDM monitoring methodology that would allow estimating CH_4 emissions mitigation from APG flaring reduction projects is available. On the other hand, the “Methodology of calculation of emissions of hazardous substances into the atmosphere due to the flaring of the associated petroleum gas at flaring stacks” developed by the Saint-Petersburg Scientific Research Institute for Protection of Atmosphere and endorsed by State Committee for Environmental Protection - GosKomEkologiya, (FGUP “NII Atmosphera”) is designed for practical usage when estimating such emissions during APG flaring.

Estimation of CO_2 reduction due to the displacement of electricity generation from the powertrains uses the elements of the Approved CDM Methodology, AM0009.

Calculations will be carried out in accordance with Table 10 (Project emissions calculation equations) – for Project line, and Table 11 (Equations for local baseline emissions at the APG flare), Table 12 (Baseline powertrains emission equations for Baseline) shown above.
Equation for annual emission reductions showed in Table 13.

3. MONITORING RESPONSIBILITY

As a beneficiary of ERU transfer, the Project Company will have the primary responsibility for collection and reporting of all data necessary for monitoring project performance according to this Monitoring Plan. The following table defines the responsibilities of the involved parties in the monitoring of the Project.

Table 2: Responsibilities of the involved parties

Item	RITEK, Project Company	Emissions Reduction Investor - ____________________
Monitoring system	♉ Review of the Monitoring Plan (MP) and suggest adjustments if necessary ♉ Establish and maintain monitoring system and implement MP ♉ Prepare for initial verification and project Commissioning	♉ Arrange for initial verification
Data collection	♉ Establish and maintain data measurement and collection systems for all MP indicators ♉ Check data quality and collection procedures regularly	
Data computation	♉ Enter data in MP workbooks ♉ Use MP workbooks to calculate emission Reduction	
Data storage system	♉ Store and maintain records ♉ Implement approval system for completed worksheets ♉ Forward annual worksheet outputs to ERI ____________________	♉ Receive copies of key records and reports ♉ Maintain ERI records
Performance, monitoring and reporting	♉ Analyze data and compare project performance with project targets ♉ Analyze system problems and recommended improvements (performance management) ♉ Prepare and forward annual reports	
MP training and capacity building	♉ Ensure that operational staff is trained and enabled to meet the needs of this MP	
Quality assurance, audit and Verification	♉ Establishment and maintain and internal approval system with a view to allowing for audits and verification ♉ Prepare for, facilitate and coordinate audits	♉ Arrange for periodic verification audits as needed

	and verification process	

The monitoring data will be reported annually to support payments for reduction achieved. The data of submission shall be decided according to agreement between RITEK and the Emissions reduction's Investor.

To protect the interests of all stakeholders in the carbon purchase agreement, it is essential that a system of report auditing and verification be established.

First, ERI representatives will do the first level review of the Annual GHG Reduction Report.

Second, all emission reductions generated by the project shall be subject to verification by an independent entity. Emissions reduction's Investor (ERI) shall instruct the independent entity to undertake verification of the emission reductions generated by the project within a reasonable time after receipt of the Monitoring Report. ERI may choose to waive its right to arrange for verification in any year. However, when ERI requests that the Annual GHG Reduction Report is to be verified in a year following a year where no verification report was produced, then verification should verify all GHG Reductions generated over the years constituting the entire period since the last verification.

OJSC "RITEK" shall be fully cooperative with ERI and the verifier in accordance with the requirements of this Monitoring Plan. OJSC "RITEK" will make available, upon request, all data required by this Monitoring Plan and will also provide the verifier with:

- The names and titles of individuals responsible for preparation of the data in the annual monitoring reports.
- Meter readings and invoices to support the electricity delivered to Project consumers and the APG received for GPP operation.
- Any other supporting documentation.

"RITEK" shall keep all data until the end of the Project's life-span in 2020.

4. MONITORING PLAN WORKBOOK TEMPLATES

The monitoring plan can be carried out according to the spreadsheet workbook. A brief explanation of each table is provided below. Throughout the workbook, color coding has been used to distinguish inputs that will be monitored throughout the crediting period (yellow); inputs that are stipulated to remain constant throughout the crediting period (green); and calculated results (blue). All entries in the workbook are to be documented by initials for the individual responsible for preparation, checking and approval.

The workbook contains the derivation of ex ante estimates of input data and emission reductions as a benchmark for comparison for future inputs and results. The layout also will accommodate actual data for 2007 to allow for testing of the monitoring procedures. This is optional but highly recommended as useful training and debugging exercise prior to completion of the required analyses for the crediting period.

Table 3 below documents the monthly meter readings at both the 6kV and 0,4kV delivery to determine the total displacement by month and year.

Table 3 Total Electric Deliveries, on fiders 6 kV and 0,4 kV necessary for estimation of energy substitution monthly and annually

Note	MWh sales data reported here must match monthly according to meter readings
Coding	Inputs
	Calculated
	Stipulated Constant

Meter reads						Hypothetical Illustration	Optional	Required
6 kV Delivery Point			Report responsibilities				2008 2008	2009 2009
Bill Period Start			Prepared by	Checked by	Approved by	Data reading	Data reading	Data reading
	Jan							
	Feb							

	Mar							
	Apr							
	May							
	Jun							
	Jul							
	Aug							
	Sep							
	Oct							
	Nov							
	Dec							
Bill period end			Prepared by	Checked by	Approved by	Data reading	Data reading	Data reading
	Jan							
	Feb							
	Mar							
	Apr							
	May							
	Jun							
	Jul							
	Aug							
	Sep							
	Oct							
	Nov							
	Dec							

MWh Delivered To 6kV System

Hypothetical Illustration

	Month	Variable		Meter calibration factor			MWh		MWh		MWh
	Jan		31				2896				
	Feb		28				2616				
	Mar		31				2896				
	Apr		30				2803				
	May		31				2896				
	Jun		30				2803				
	Jul		31				2896				
	Aug		31				2896				
	Sep		30				2803				
	Oct		31				2896				
	Nov		30				2803				
	Dec		31				2896				
							34100				

Tables 4 and 5 documents the MWh produced by the emergency diesel generator and the fuel used for this generation. The efficiency check should easily detect and out of range entries.

Table 4 Electric Production by Emergency Diesel Generator (MWh)

Note: This output can be metered or estimated based on measured fuel consumption and a stipulated efficiency.

QA/QC		Prepared by	Checked by	Approved by	Hypotetical illustration			2008		2009
Jan										
Feb										
Mar										
Apr										
May										
Jun										
Jul										
Aug										
Sep										
Oct										
Nov										
Dec										
Total	*Emgen*									

Table 5 Annual Fuel Consumption by Diesel Generator (MWh)

Items		Prepared by	Checked by	Approved by	Units	Illustration		2008		2009
Use					Litres					
Calorific value					Mj/litre					
Fuel input					MW					
Efficiency check					%					

Table 6 (a) summarizes the total electric deliveries from the GPP which equal the total deliveries less the production of the emergency generator. Table 6 (b) documents summarizes the total heat delivery from the HS.

Table 7 records the monthly deliveries of APG expressed in terms of thousand standard cubic meters (TCM). APG density, calorific value and molecular mass are also shown here. These APG characteristics have tight tolerances specified by contract and have thus been stipulated as fixed throughout the future at their expected average values. These parameters are monitored continuously and could be reported on an ongoing basis but that adds unnecessary complexity to the calculations. The technical tolerances are 5% for density and 3% for calorific value and molecular mass. Since the ex ante expected value for molecular mass was 24.87 kg/mole, that value has been used for all ex ante calculations in the PDD. Operating experience shows approximately the same figures. Therefore, the lower value has now been used as the stipulated figure.

Table 6 (a) Monthly Deliveries from GPP

Electricity			Units	Illustration		2008		2009
Jan			MWh	2896				
Feb			MWh	2616				
Mar			MWh	2896				
Apr			MWh	2803				
May			MWh	2896				
Jun			MWh	2803				

Jul			MWh	2896				
Aug			MWh	2896				
Sep			MWh	2803				
Oct			MWh	2896				
Nov			MWh	2803				
Dec			MWh	2896				
Total	*ElecDelTotal*							

Table 6 (b) Monthly heat deliveries from HS

Heat			Units	Illustration		2008		2009
Jan			Gcal					
Feb			Gcal					
Mar			Gcal					
Apr			Gcal					
May			Gcal					
Jun			Gcal					
Jul			Gcal					
Aug			Gcal					
Sep			Gcal					
Oct			Gcal					
Nov			Gcal					
Dec			Gcal					
Total	*ElecDelTotal*							

Table 7 Monthly GPP and HS Use of APG

Month	Variable name	Prepared by	Checked by	Approved by	Units	illustration		2008		2009
Jan					TCM	808				
Feb					TCM	792				
Mar					TCM	808				
Apr					TCM	802				
May					TCM	808				
Jun					TCM	808				
Jul					TCM	802				
Aug					TCM	808				
Sep					TCM	802				
Oct					TCM	808				
Nov					TCM	802				
Dec					TCM	808				
Total APG Input	*V APG*				TCM	9676				
APG Density	*ρ APG*				kg/SCM	1,110		1,110		1,110
Total APG input	*tAPG*				t APG	10,745				

Calorific Value	*LHV APG*		MWh/SCM	0,0102		0,0102		0,0102
Total fuel Input	*APG MWh*		MWh					
Net efficiency Check	*GPP effnet*		%	39,7				
Molecular mass of APG	*µ APG*		kg/mole	24,87		24,87		24,87

Table 8 accommodates entry of the composition data of the APG at the monthly level and the calculation of the volume-weighted annual composition figures to be used for project emission estimates.

Table 8 APG Monthly Composition Table

This table displays the monthly APG volume composition with input based on data gathered on the second Tuesday of each month. The values entered will be the volume-weighted hourly averages for those days

Prepared by:
Checked by
Approved by

	1	2	3	4	5	6	7	8	9	10	11	12	
Percent APG use	808	792	808	802	808	808	802	808	802	808	802	808	
Hydro carbon	Jan % vol	Feb % vol	Mar % vol	Apr % vol	May % vol	Jun % vol	Jul % vol	Aug % vol	Sep % vol	Oct % vol	Nov % vol	Dec % vol	Annual
CH_4	76,00	76,00	76,00	76,00	76,00	76,00	76,00	76,00	76,00	76,00	76,00	76,00	76,00
C_2H_6	4,89	4,89	4,89	4,89	4,89	4,89	4,89	4,89	4,89	4,89	4,89	4,89	4,89
C_3H_8	7,25	7,25	7,25	7,25	7,25	7,25	7,25	7,25	7,25	7,25	7,25	7,25	7,25
C_4H_{10}	3,80	3,80	3,80	3,80	3,80	3,80	3,80	3,80	3,80	3,80	3,80	3,80	3,80
C_5H_{12}	1,68	1,68	1,68	1,68	1,68	1,68	1,68	1,68	1,68	1,68	1,68	1,68	1,68
C_6H_{14}	1,62	1,62	1,62	1,62	1,62	1,62	1,62	1,62	1,62	1,62	1,62	1,62	1,62
C_7H_{16}	1,49	1,49	1,49	1,49	1,49	1,49	1,49	1,49	1,49	1,49	1,49	1,49	1,49
C_8H_{18}	0,72	0,72	0,72	0,72	0,72	0,72	0,72	0,72	0,72	0,72	0,72	0,72	0,72
CO_2	1,08	1,08	1,08	1,08	1,08	1,08	1,08	1,08	1,08	1,08	1,08	1,08	1,08
N_2	1,47	1,47	1,47	1,47	1,47	1,47	1,47	1,47	1,47	1,47	1,47	1,47	1,47
Total	100,0	100,0	100,0	100,0	100,0	100,0	100,0	100,0	100,0	100,0	100,00	100,00	100,00

Table 9 contains key calculations of APG properties based on the volume composition data derived in Table 7. The temperature figure shown is calculated based on 5 degrees C for October to April and 10 degree C for May through September. Alternate parameters are shown to capture the mode of operation of the Vostochno-Perevalnoye flare. Calculations of the black-firing test using the NII "Atmosfera" methodology and typical flare volumes show that the Vostochno-Perevalnoye flare has operated in black-firing mode for at least the past decade. An increase in the volume of APG flared of more than 10% would be required to move the flare out of black firing mode unless the flare stack were substantially reconstructed. For these reasons, continued operation of the Vostochno-Perevalnoye flare in black-firing mode has been assumed throughout the crediting period. Photographs will be taken of the flare stack on the second Tuesday of each month to verify whether significant reconstruction has taken place. If not, continued operation in black-firing mode will be assumed.

Table 9 Annual APG analysis

Index	Parameter	Unit	Value
ρAPG	Density	kg/nm3	1,110
LHV ApG	Low heating value	Kcal/nm3	8731
		MWh/nm3	0,0102
t	temperature	Celcium	7,1

Index		Units	Value
D	Stack diameter	m	0,2
GWP CH4			21

Index	Vi	ρI	mi	μi	ki	∂c-i	∂i		kAPG	∂c-APG	∂CH4
Component	Volume fraction weighted average or monitor	Density of hydrocarbons	Molecular mass of components	Molecular mass of i-components	Adiabatic index of i-components	Mss content of carbon of i-component	Mass fraction of i-component		Adiabatic index of APG	Mass fraction of i-component in APG	Hydro carbons in CH4e
	% vol	kg/m3	kg/mole	kg/mole		% mass	%			%	%
CH_4	74,35	0,716	16,043	12,19268	1,31	74,87	0,49000		0,9956	36,6862	0,489999
C_2H_6	4,21	1,342	30,07	1,470423	1,21	79,98	0,05909		0,0592	4,7262	0,110759
C_3H_8	10,01	1,969	44,097	3,197033	1,13	81,71	0,12854		0,0819	10,5033	0,353326
C_4H_{10}	6,72	2,595	58,124	2,208712	1,1	82,66	0,08880		0,0418	7,3398	0,321706
C_5H_{12}	1,9	3,221	72,151	1,212137	1,08	83,24	0,04873		0,0181	4,0560	0,219142
C_6H_{14}	0,71	3,842	86,066	1,394269	1,07	83,73	0,05605		0,0173	4,6927	0,300668
C_7H_{16}	0,22	4,468	100,08	1,491192	1,06	84,01	0,05995		0,0158	5,0361	0,373964
C_8H_{18}	0,06	3,8	114,23	0,822456	1,05	84,21	0,03307		0,0076	2,7844	0,235432
CO_2	0,3	1,977	44,011	0,475319	1,3	27,29	0,01923		0,0140	0,5247	
N_2	1,52	1,251	28,016	0,411835	1,04		0,01656		0,0153	1,6559	
Total	100			24,9738				Total	1,2667	76,3495	2,404993
								CH4 mass share			

Specific emissions of CO, kg CO/kgAPG	non black-firing	0,02	RosG	Molecular mass of CO	Kg/mole	21
	black-firing	0,25	RosG			

Underfiring coefficient	non black-firing	0,0006	RosG			
	black-firing	0,035	RosG			

Table 10 requires no additional inputs. Rather, the entire table calculates the baseline emissions at the Vostochno-Perevalnoye flare using the NII "Atmosfera" methodology.

Table 10: Baseline Emissions at Vostochno-Perevalnoye APG flaring

Step 1	Determining mass amount of APG flared, kg	Ex-ante illustration

Index	Parameter	Units	Value
V APG	Annual volumetric flow of APG to be flared	ncm (1000)	
ρ APG	Density of APG	kg/nCM	
M APG	Mass amount of APG flared	T	
Step 2	Calculation of APG molecular mass		
Index	Parameter	Units	Value
μ APG	Molecular mass of APG	kg APG/mole	
Step 3	Determining physical-chemical characteristics of APG		
Index	Parameter	Units	Value
K APG	adiabatic index of APG		
σ c_APG	Mass fraction of i-comp in APG	% mass	
Kc	Quan. Of carbon atoms in molecular APG	carbon atoms	
Step 4	Non-black flaring test: Discharge jet flow > 0,2 Sound velocity in APG flared		
Index	Parameter	Units	Value
U flow	APG`s discharge jet flow velocity	m/s	
U sound	Sound velocity in APG flared	m/s	
	Result of the test		black firing

Step 5. CH4 emissions due to incomplete burning			
Index	Parameter	Units	Value
k u/f	Under-firing coefficient	-	
σ CH4	CH4 mass fraction	% mass	
e CH4_baseline	CH4 emission factor _ baseline	kgCH4/kgAPG	
MAPG	APG flared per year	kgAPG	
E CH4_baseline	Total CH4 emissions _ baseline	tCH4	
		tCO2e	
Step 6. Total CO2 emissions from APG flaring			
Index	Parameter	Units	Value
μ CO2	Molecular mass of CO2	kg CO2/mole	

Kc	Quan. of carbon atoms in molecular APG	carbon atoms	
μ APG	Molecular mass of APG	kg/mole	
e CH4_baseline	CH4 emission factor baseline	kgCH4/kgAPG	
μ CH4	Molecular mass of CH4	Kg CH4/kg mole	
e CO_baseline	CO emission factor _ baseline	kgCO/kgAPG	
μ CO	Molecular mass of CO	kgCO2/mole	
e CO2	CO2 emission factor _ baseline	kgCO2/kgAPG	
M APG	APG flared per year	kgAPG	
E CO2 complete baseline	CO2 emissions from complete burning	tCO2e	

Table 11 simply provides reporting of the results from Table 10 throughout the trial period and then throughout the crediting period.

Table 11: Baseline total CO_2e emissions from APG flaring

year	APG combustion engines	CO2 emission factor flaring	CH4 emission factor _ baseline	CO2 emissions from complete burning	Total CH4 emissions in terms of tCO2e	Total baseline emissions
		eCO2_baseline	*e CH4_baseline*	*E $_{CO2}$ complete baseline*	*E CH_4 baseline*	*ECO2e_total baseline*
	tAPG	tCO2/tAPG	Kg CH4 / kg APG	tCO2e	tCO2	tCO2e
Ex-ante illustration	10745	2,1751	0,0842	23373	18994	42367
2008	3366	2,1751	0,0842	7321	5950	13271
2009	10745	2,1751	0,0842	23373	18994	42367
2010	10745	2,1751	0,0842	23373	18994	42367
2011	10745	2,1751	0,0842	23373	18994	42367
2012	10745	2,1751	0,0842	23373	18994	42367

Table 12 develops the estimated baseline emissions at powertrains that are displaced by the Project generation of electricity for local use at Vostochno-Perevalnoye. Specific data on electric quantities explants entering are not available in the frame of Project. From the other side losses on the local grid (6 kV) can be estimated in comparison electricity on GPP fiders and total local consumption. Such losses can be determined as absolute due to an autonomous status of grid. Besides it is evident, that energy consumption will grow (because of decreasing pressure in well and increasing energy costs for oil extraction). But in a view of conservative emission's estimation conception – consumption defined as a stable till the end of 2012.

Table 12 also converts power generation to gross CO2 emissions. Finally, Table 10 introduces the powertrains emission factor that has been quantified using elements of AM0009.

Table 12 Baseline CO2 Emissions at the Powertrains

Index	*ElecDel Total*	*EF*	*TUF*	*total_energy*	*carbon_factor*	*total_carbon*	*trains_CO2*

Year	Total Electricity Delivered to GPP feeders	Emission factor	Total fuel consumption	Energy per ton of unified fuel	Default carbon content	Total C content	CO2 emission
	MWh	tuf/MWh	Tuf	MJ/t	kg/GJ	kg	tCO_2
GPP	34,079	0,596	20,311	29300	20	595115	43641,7
HS	11,423	0,596	6,808	29300	20	199478	14629,0
2008	0	0,596	0	29300	20	0	0
2009	0	0,596	0	29300	20	0	0
2010	0	0,596	0	29300	20	0	0
2011	0	0,596	0	29300	20	0	0
2012	0	0,596	0	29300	20	0	0

Table 13 then collects the annual results in summary form for all years of the crediting period.

Table 13 Total Baseline Emissions

Index	*ECO2 flaring_baseline*	*ECO2_total*	*ECO2e_total_baseline*
Year	Total CO2 emissions from APG flaring	Total CO2 emissions from trains	Total baseline emissions
	tCO2e	tCO2e	tCO2e
Ex-ante illustration	42367	58270	100637
2008	#DIV/0!	0	#DIV/0!
2009	#DIV/0!	0	#DIV/0!
2010	#DIV/0!	0	#DIV/0!
2011	#DIV/0!	0	#DIV/0!
2012	#DIV/0!	0	#DIV/0!

Table 14 relies on a single input which equals the net capacity per gas engine which is stipulated. The net capacity is used to calculate the number of full time equivalent engines that are operative in a year. This step was necessary to allow use of the EIA method of calculating gas engine emissions which were developed on a per engine basis. It should be noted that the Project includes sophisticated instrumentation and control systems that allow careful control and measurement of emissions from the GPP and that experience to date has shown that emissions of GHG are negligible. Thus, the use of the EIA methodology is demonstrably conservative.

Table 14: Project CO2 Emissions Calculation			Ex ante			
			illustration		2008	2009
APG combustion in Project gas power plant (GPP)						
M_APG	Mass amount of APG flared	t	9839,3			
σ c_APG	Carbon mass fraction in APG	%	76,3495			
μ CO2	Molecular mass of CO2	kgCO2/mole	44			
μ C	Molecular mass of carbon	kgC/Mole	12			
ECO2_combustion project	Total CO_2 emissions project	tCO_2	38794,6			
APG combustion in Project heating station (HS)						
M_APG	Mass amount of APG flared	t	906,0			
σ c_APG	Carbon mass fraction in APG	%	76,3495			
μ CO2	Molecular mass of CO2	kgCO2/mole	44			
μ C	Molecular mass of carbon	kgC/Mole	12			

ECO2_combustion project	Total CO_2 emissions project	tCO_2	3572,2			

Table 15 provides a simple calculation of the emissions from the emergency diesel generator in the event that it should operate during the year. To date, this generator has not been utilized since back-up generation has always been provided from the reserve gas engines.

Table 15	**Emissions From Emergency Generator**				2008	2009
Emgen_fuel	Electricity by emergency diesel generator	MWh	0		0	0
Diesel fuel EF	Emissions factor for electricity by diesel generator	tCO2/MW	0,2626		0,2626	0,2626
Emgn_CO2	Total emissions_emergency diesel generator	tCO2	0		0	0

Table 16 provides calculation of the total annual Project emissions as a sum of the CO_2e emissions from gas engines and CO_2 emissions from emergency diesel generator if applicable.

Table 16 Total Project Emissions

year	APG combustion engines	Carbon mass fraction in APG	Molecular mass of CO2	Molecular mass of C	Diesel generator emissions	Total emissions project
		σ c_APG	*μ CO2*	*μ C*	*Emgn_CO2*	*ECO2e_total project*
	tAPG	% mass	kgCO2/mole	kgC/mole	tCO2	tCO_2e
Ex-ante illustration	10745	76,3495	44	12	0	30081
2008	3365	76,3495	44	12	0	9423
2009	10745	76,3495	44	12	0	30081
2010	10745	76,3495	44	12	0	30081
2011	10745	76,3495	44	12	0	30081
2012	10745	76,3495	44	12	0	30081

Finally, Table 17 combines the annual baseline and project emission estimates to derive the emission reductions for each year in the crediting period.

		Prepared by:	
		Checked by:	
		Approved by:	
Table 17 Total Emission Reductions			
Year	Total baseline emissions	Total project emissions	Total emission reductions
	tCO2	tCO2	tCO2
Ex Ante Illustration	100637	30081	70556

2008	#DIV/0!	#DIV/0!	#DIV/0!
2009	#DIV/0!	#DIV/0!	#DIV/0!
2010	#DIV/0!	#DIV/0!	#DIV/0!
2011	#DIV/0!	#DIV/0!	#DIV/0!
2012	#DIV/0!	#DIV/0!	#DIV/0!

Annex 4

MAIN ELEMENTS OF THE METHODOLOGY OF CALCULATION OF EMISSIONS OF HAZARDOUS SUBSTANCES INTO THE ATMOSPHERE DUE TO THE FLARING OF THE ASSOCIATED PETROLEUM GAS AT FLARING STACKS

Data on flaring conditions and key characteristics of APG necessary for calculations of emissions of hazardous substances into the atmosphere due to the flaring of the associated petroleum gas at flaring stacks:

Indicator	Unit	Comments
V_{APG}	Nm3	Annual volumetric flow of APG to be flared
t	°C	Temperature of APG before flaring
D	m	Stack' pipe diameter
V_{APG}	% vol	Volumetric composition of APG
V_i	% vol	Volumetric concentration *i*-component in APG
ρ_{APG} ρ_i	Kg/m3	Density of APG and its components
m_i	Kg/mole	Molar mass of *i*-component in APG
k_i	Scalar	Adiabatic index of *i*-component in APG
σ_{C-i}	% mass	Mass content of carbon of *i*-components in APG

Step 1. Determining of mass amount of APG flared, kg

$$M_{APG} = V_{APG} * \rho_{APG}$$

Step 2. Calculation of APG molecular mass

$$\mu_{APG} = \Sigma \ 0.01*V_i* m_i;$$

Step 3. Determining physical-chemical characteristics of APG

3.1. Adiabatic index of APG (K_{APG}):

$$K_{APG} = \Sigma \ 0.01* V_i * k_i;$$

3.2. Mass fraction of i-component in APG (σ_i):

$$\sigma_i = 0.01*V_i * \rho_i/\rho_{APG}$$

3.3. Mass fraction of carbon in APG (σ_C):

$$\sigma_{C\_APG} = \Sigma \ \sigma_i * \sigma_{C-i}$$

3.4. Quantity of carbon atoms in molecular formula of APG (Kc):

$$Kc = 0.01*(\sigma_{C\_APG}/\mu_c)* \mu_{APG}$$

μ_c - molecular mass of carbon equals to 12.

Step 4. Non-black firing test

This test determines combustion efficiency of the APG flaring. The formulae used:

4.1. The condition of non-black firing:

$if\ U_{flow} > 0{,}2\ U_{sound}$

then the soot does not discharges from the stack's pipe, the APG burning is complete.

$if\ U_{flow} < 0.2\ U_{sound}$,

the soot discharges that demonstrating incomplete burning of APG. In this case, under-firing coefficient equal to 0,035 must be taken into account in further calculations:

4.2. APG's discharge flow velocity, m/sec (U_{flow}):

$$U_{flow} = 4*W_v/(\pi *d_2)$$

W_v – APG volumetric flow, m3/s;
d – Vostochno-Perevalnoye oil field stacks diameter is equal to 0,2 m and 0,3 m;

4.3. Sound velocity in APG flared, m/sec (U_{sound}):

$$U_{sound}=91.5*(K*(T_{APG}+273)/\mu_{APG})_{0.5}$$

K_{APG} - adiabatic index of APG
$K_{APG} = \Sigma\ 0.01* V_i * k_i;$
Vi, - volumetric concentration i-component in APG, % vol;
ki – adiabatic index of i-component in APG;
T_{APG} – temperature of APG, °C;
μ_{APG} – molecular mass of APG, kg/mole.

Step 5. Determining CH_4 emissions due to incomplete burning

5.1. CH_4 emission factor, kg CH_4/kg APG (e_{CH4})

$$e_{CH4} = 0.01* \text{under-firing ratio} * \sigma_{CH4}$$

σ_{CH4} – CH_4 mass fraction, %.

5.2. CH_4 emissions, tonnes of CH_4 (E_{CH4})

$$E_{CH4} = 0.01 *e_{CH4} * M_{APG;}$$

Step 6. Determining CO_2 emissions, taking into account the incomplete burning

6.1. CO_2 emission factor, kg CO_2/kg APG (e_{CO2})

$$e_{CO2} = \mu\ CO_2\,(k_C/\mu_{APG} - e_{CH4}/\mu\ CH_4 - e_{CO}/\mu\ CO)$$

e_{CO} – CO emission factor, kg CO/kg APG; equals to 0,25

μ_{CO_2} – molecular mass of CO_2, equals to 44;

μ_{CH_4} – molecular mass of CH_4, equals to 16;

μ_{CO} – molecular mass of CO, equals to 28

6.2. CO_2 emissions, taking into account the incomplete burning, tCO_2 (E_{CO2})

$$E_{CO2} = e_{CO2} * M_{APG}$$

Step 7. Determining total CO_2 equivalent emissions

$$E_{CO2e\_flaring} = E_{CO2} + E_{CH4} * GWP_{CH4}$$

GWP_{CH4} - Global Warming Potential, equals to 21 for methane.