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

CONTENTS

Annexes

SECTION A. General description of project activity

A.1. Title of the project activity:

Construction of Combined Heat and Power Plant (CHPP) at SE "Tirotex", Tiraspol City, Republic of Moldova

Version number: 3.5
Date: 18 August 2011

A.2. Description of the project activity:

The project aims at construction of new Combined Heat and Power Plant (CHPP) which will ensure combined generation of electricity and heat in the form of dry-saturated steam. The project envisages installation of gas engine cogeneration sets (gensets) with utilisation of flue gases heat in recovery boilers for production of steam which is used to cover technological needs of the facility and heating purpose. Natural gas will be the main fuel for new CHPP.

The baseline scenario is a continuation of current situation. Currently steam for technological needs of the enterprise is supplied from own steam boiler house (SBH) which has been in operation since 1973 and has five operating boilers:

2 new steam boilers DE 25/14 commissioned in 1998 (25 tons of steam per hour);

3 older ones GM 50/14 installed in 1973 (50 t/h).

Natural gas is the main fuel at the SBH. Electricity for needs of SE "Tirotex" is generated at Moldovian TPP.

Construction of the new CHPP will result in SBH closure as the thermal capacity of the new plant will be sufficient to cover some part of the consumers' load. The existing equipment of the SBH will be mothballed.

The main part of electricity in the Republic of Moldova is imported from neighbouring countries Ukraine and Romania (ca. 70%). The rest is generated at steam-turbine TPPs and CHPs. Currently natural gas is the main fuel at these plants. Their net efficiency factor of power generation does not exceed 35%.

Combined heat and electricity generation by gas engine cogeneration gensets will be the first implementation of the technology in the Republic of Moldova and will allow increasing efficiency of fossil fuel use. The amount of electricity generated at the new plant will replace grid electricity generated at existing power plants.

Currently, SE "Tirotex" is directly consuming electricity produced at nearby Moldovian TPP. The electricity is produced in the exchange of the delivery of natural gas from SE Tirotex. After implementation of the project enterprise electricity demand of the enterprise will be fully covered by CHPP and the excess electricity will be delivered to other nearby consumers in the grid.

The following main energy equipment will be installed at the new CHPP:

- 8 units based on gas reciprocating engines TCG2032V16 manufactured by German company "Deutz", each of them has 3916 kW electric and 4173 kW thermal capacities;
- 4 steam recovery Viessmann boilers with the total steam production of about 21.2 t/h with 8 heat-exchangers M10 MFG for water heating with single capacity of 1878 kW .

The project will be implemented in 2 stages:

- 1st stage: installation of 6 cogeneration units with total electric capacity of 23.496 MW and 3 steam recovery boilers, with the single boiler capacity of 5.3 t/h steam. About 75% of the total electric capacity (17.6 MW) will be used for own technological needs of the enterprise and 25% (5.874 MW) will be used for delivery of electricity for external consumers of the grid. Heat produced at CHPP will be 100% utilised at the enterprise for technological needs and heating of premises;

- 2nd stage: installation of 2 cogeneration units of total 7.83 MW and 1 steam recovery boiler: 100% of power produced will be delivered to the grid to other customers, 100% of the heat produced will be utilised at SE "Tirotex". This stage is foreseen to be implemented in 1 year after commencement of 1st stage.

The project implementation will result in:

- additional electricity generation that covers own needs and surplus supplied to the grid;
- avoiding of steam and hot water supply from existing SBH;
- increase of fossil fuel use efficiency;
- reduction of GHG emissions from fossil fuel combustion by 41,162 tonnes of CO2e per year;
- decrease of emissions of polluting substances into the atmosphere;
- increase of local employment (about 14 new jobs).
- decrease of the leakages within the project boundaries

The estimated total investment cost of the project is about EUR 18.3 million. The project idea has been discussed since 2005, however project needed 70% loan financing. Bank requested to strengthen the financial indices of the project, which could be achieved through additional income from Kyoto mechanism. Therefore, since 2006 SE "Tirotex" has started investigation of possibilities to develop the project as CDM activity. The PIN for the Project was developed in 2008 and letter of endorsement was issued by Designated National Authority on February 06, 2009.

The main scope of construction works has been implemented since October 2008 (after the construction permit was issued – on 09 October 2008) and initially start of 1st stage of the project was planned for April 2009. Respective start of the 2nd stage was planned for April 2010. However, due to technical delays commencement of 1st project phase was postponed till the January 2010, and respectively, 2nd phase is expected to be started in January 2011.

Project's contribution to Sustainable Development

The project helps in achieving sustainable development of industries in the region by supplying them with clean power based on natural gas. The natural gas is a clean gas and there will not be any particulate emissions during the operation of cogeneration plant.

SE "Tirotex" is one of the largest industrial enterprises in the region, so implementation of the project activity in this part of the country would certainly play an important role in the development of power-generating scenario of Tiraspol. It would help to cover own needs of the enterprise in electricity and supply a part of "clean" electricity to the grid.

Also the project increases local employment.

The project foresees continuous revenues from CER sales.

The project activity makes a good environmental effect as a reduction of carbon emissions and saving of coal resource for power production.

A.3. Project participants:

Name of Party involved (host) indicates a Host Party)	Private and/or public entity(ies) project participants (as applicable).	Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)

Republic of Moldova (Host Party)	SE “Tirotex”	No
The Netherlands	Vattenfall Energy Trading Netherlands N.V.	No
(*) In accordance with the CDM modalities and procedures, at the time of making the CDM-PDD public at the stage of validation, a Party involved may or may not have provided its approval. At the time of requesting registration, the approval by the Party(ies) involved is required.		

1) State Enterprise “Tirotex” – legal entity, textile enterprise in Tiraspol city, Republic of Moldova;
2) Vattenfall Energy Trading Netherlands N.V. – European electricity generation utility.

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

A.4.1.1. Host Party(ies):

The Republic of Moldova

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

Tiraspol city

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

Tiraspol city

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

Tiraspol is the city of The Republic of Moldova with around 180,000 inhabitants.(Fig. A.4-1) Tiraspol is the largest industrial and cultural centre of the region. The largest industrial enterprises such as “Litmash”, “Electromash”, “Moldavisolit”, SE “Tirotex”, “Quint”, plant of Metal goods are located in Tiraspol. Tiraspol State Enterprise “Tirotex” is the biggest textile enterprise in the south-west of the CIS. The project activity is located at the site owned by SE “Tirotex” within the industrial area located at the northern outskirts of Tiraspol (Fig. A.4-2). It is a unique industrial complex occupying an area of 58 ha with well developed infrastructure. The SE “Tirotex” includes 2 spinning and weaving factories, one finishing factory, sewing factory, automobile base, agricultural complex, "Textile" Scientific research institute and several other smaller factories.

Geographic latitude: 46°84'95"N. Geographic longitude: 29°66'80"E. Time zone: GMT +2:00.

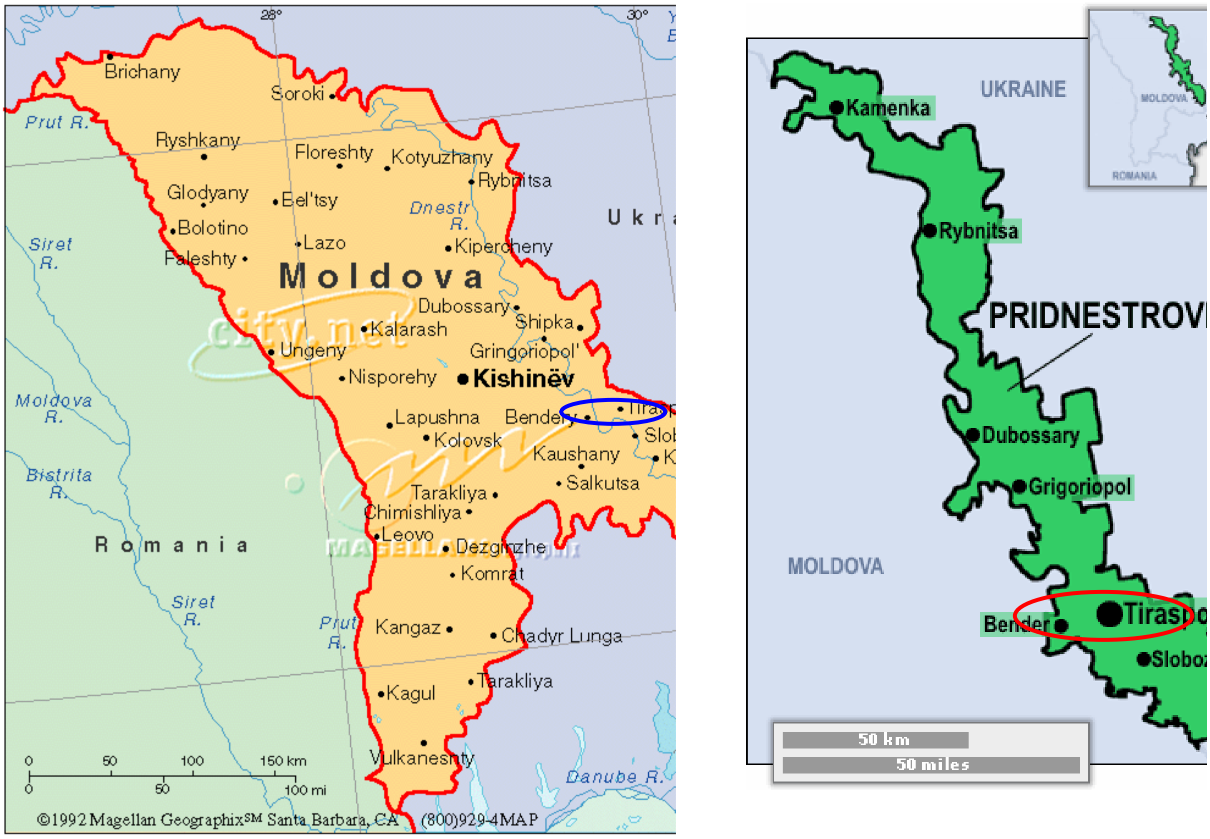

Figure A .4-1. Map of Republic of Moldova and Pridnestrovie

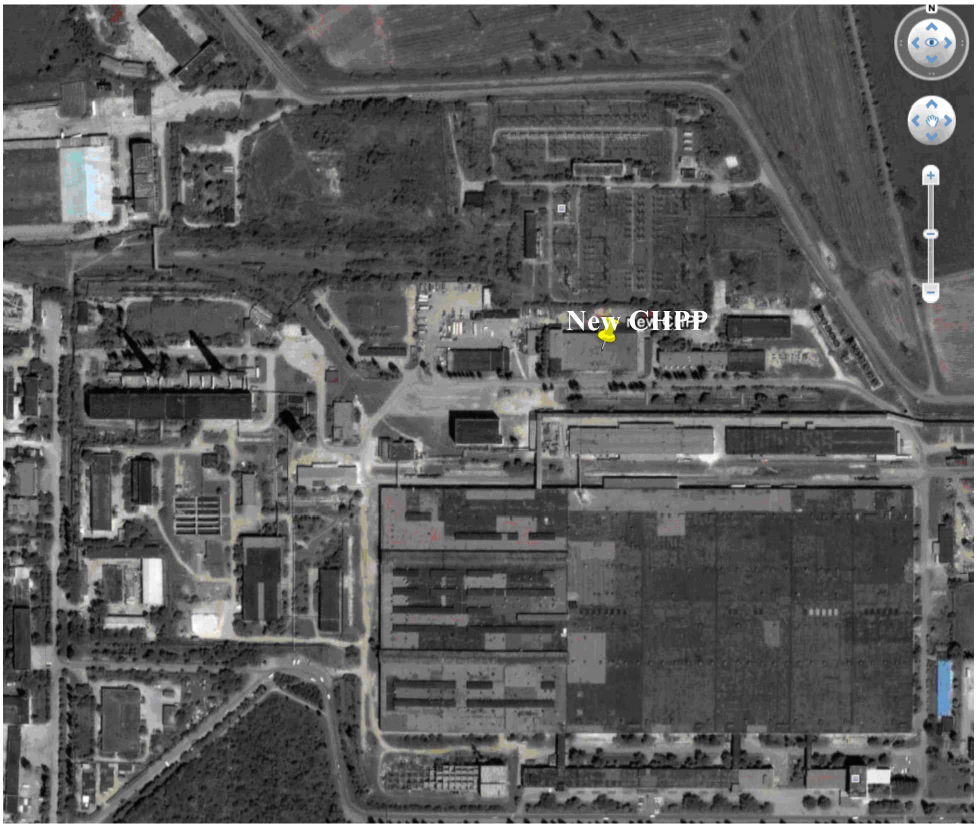

Fig. A.4-2. The Google Earth map indicating the location of the project activity

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

Sectoral Scope 1: Energy industries (renewable - / non-renewable sources)

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

The technology to be applied in the project is a CHPP designed for combined heat and power production.

Combined Heat and Power Plant (CHPP). The primary energy source at the CHPP is natural gas used for production of two kinds of energy: thermal and electrical energy.

The CHPP consists of gas-reciprocating engine, generator, heat exchanger, control panel, system inter-connection line. Gas-reciprocating engine has thermal efficiency of 44.8% that is better than the conventional types of steam turbines that are currently used by boiler-houses in Republic of Moldova. Each CHP unit has 3,916 kW of electric capacity and 4,173 kW of thermal capacity. The table A4-1 indicates main specifications of the gas-reciprocating engine TCG2032V16 produced by company "Deutz" (Germany) applied for in the project (fig. A.4-3).

The CHPP will provide the SE "Tirotex" by heat and steam for technological processes at enterprise and also by on-site source of power. Excess of electricity produced will be delivered to the grid to supply other industrial enterpises.

Fig. A.4-3. General view of gas engine cogeneration gensets of TCG2032V16 type

The main advantage of cogeneration against separate generation is lower fossil fuel consumption for generation of the same amount of heat and electricity. Large amount of heat escapes into the atmosphere through steam condensers, cooling towers, etc. during operation of thermal power plants (TPPs), this is associated with technological peculiarities of the process. Energy efficiency of TPPs is 30-50%. Energy generation efficiency increases up to 80-90% when gas engines cogeneration gensets are operated with utilization of heat of exhaust gases, engine jacket water, air/fuel mixture and lube oil.

Table A.4-1. Basic Specifications of gas-reciprocating engine TCG2032V16 produced by company "Deutz" (Germany)

Electric power, kW_{el}	Electric efficiency, %	Thermal power, kW_{th}	Thermal efficiency, %	Total efficiency, %
3,916	41.9	4,173	44.8	86.7

Source: Deutz AG – producer of equipment. http://www.deutz.com

CHP technology has been applied in many European countries and has proved record of effective energy use. Thus, it is unlikely that they will be superseded by other superior technology during the project period.

The purpose of the project activity is generation of additional electricity for own needs and supply to the grid. In this case steam for the enterprise will be generated as a byproduct by means of steam recovery boilers. It allows to increase electricity independence of the enterprise from power grid and to increase efficiency of steam generation.

Prior to the start of project activities, the enterprise consumed grid electricity and steam from the old steam boiler house. Characteristics of this equipment are following:

- Steam boiler GM-50/14 – 4 units – installed capacity 110MW – efficiency 90% - year of commissioning 1973;
- Steam boiler DE-25/14 – 2 units – installed capacity 27 MW – efficiency 90% - year of commissioning 1998.

The following GHG's emission sources are considered in the project:

-Project emissions:

- CO2 emissions from the combustion of fossil fuel to produce steam and electricity at the CHPP.

-Baseline emissions:

- CO2 emissions from the combustion of fossil fuel (natural gas) to produce steam at the SE "Tirotex";
- CO2 emissions from electricity production at the Moldovian TPP;
- CO2 emissions from production (in the grid) of electricity used by other project customers, that will be replaced by power produced at CHPP.

More detailed information about GHG's emission sources is provided in section B.3. of the PDD.

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

The crediting period chosen for the proposed project is 7 years renewable 3 times. The total emission reductions for the first period to be achieved by the project are estimated to be approximately 288,134 tCO2 -eq. over the first 6 years of the crediting period with annual emission reduction of about 41,162 tCO2e/yr (tonnes carbon dioxide equivalent per year). (table A.4-2). The calculated average annual emission reductions achievable are conservative estimates based on the approved by National Moldovian DFP (National Commission of UNFCCC and Kyoto Protocol Implementation in the Republic of Moldova) grid emission factor of 0.4224 tCO2/MWh for the first crediting period. The actual CERs will be calculated ex-post following the fulfilment of the project monitoring activities.

Table A.4-2: Estimated emissions reductions

Length of the crediting period	
Year	**Estimate of annual emission reductions in tones of CO_2 equivalent**
2012	41,162
2013	41,162
2014	41,162
2015	41,162
2016	41,162
2017	41,162
2018	41,162
Total estimated emission reductions over the	288,134

1st renewable crediting period (tones of CO_2 equivalent)	
Annual average of estimated emission reductions over the crediting period/period within which CERs are to be generated (tones of CO_2 equivalent)	41,162

The calculations were done according to the following project schedule:

- start of 1st stage of the project - January 2010.
- start of the 2nd stage - January 2011.

A.4.5. Public funding of the project activity:

No public funding will be applied to the project.

SECTION B. Application of a baseline and monitoring methodology

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

The CDM methodology "**New cogeneration facilities supplying electricity and/or steam to multiple customers and displacing grid/off-grid steam and electricity generation with more carbon-intensive fuels**" version 03 of AM0048 is appropriate.

"Tool to calculate the emission factor for an electricity system" (Version 02, 16 October 2009) is used to estimate the emission factor for the grid electricity.

"Tool for the demonstration and assessment of additionality" (Version 05.2, 26 August 2008) is used for additionality demonstration.

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

The version 03 of AM0048 baseline and monitoring methodology is applicable as the project activity meets all applicability requirements as demonstrated below (see Table B.2-1);

Table B.2-1. Comparison of proposed project activity with applicability of the methodology

AM0048 Applicability	Proposed project activity
Fossil-fuel-fired cogeneration project activities that supply steam and electricity generation to multiple project customers, including both grid and off-grid applications	Applicable, approx. 75% of electricity from the 1st stage of CHPP will cover own needs of the company and about 25% will be supplied to the grid: electricity from the 2nd stage will be supplied to number of project customers in the grid. Heat energy from heat-recovery boilers will cover own needs of the company – project customer.
If a project customer is expected to have replacement and/or major repair and maintenance of on-site electricity and steam equipment during the project lifetime which might result in fuel switch and/or changes in efficiency they shall be excluded from the project activity after the likely or actual date of the replacement or major repair and maintenance.	Applicable, there is no on-site electricity generation equipment and steam production boilers can be operated during the project lifetime without major repair/maintenance which might result in efficiency increase. The older boilers are mostly used as reserve and can be operated for the next 10 years.

The existing capacity is available at project customers previous to the implementation of the project activity.	Applicable, SE Tirotex has its own steam boiler house to cover technological needs and electricity is supplied from the electricity grid in the baseline scenario Other grid customers that will purchase electricity produced in the project are existing industrial enterprises currently consuming electricity from the grid.
Project customers do not cogenerate steam and electricity in the baseline scenario.	Applicable, on site there is only heat produced and electricity is secured from external source-electricity grid.
The project customers ensure that the equipment displaced by the project activity will not be sold or used for other purposes.	Applicable, the equipment of the steam boiler house will be mothballed.

Prices, tariffs and operational costs (wages, maintenance costs) were based on the following data:

Questionnaire of the enterprise (see Annex 3-13);

Business-plan for construction of CHPP (provided to AIE);

Available national data (currency exchange rate, etc.).

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

According to the selected methodology version 03 of AM0048 the implementation of the project will result in GHG emissions reduction from fossil fuel combustion. CO2 is the main greenhouse gas produced from fuel combustion. CH4 and N2O emissions from fuel combustion are negligibly small compared to CO2 emissions and were not taken into account in the development of the project.

Table B.3-1 illustrates which emission sources are included in or excluded from the project and baseline boundaries.

Table B.3-1. Emissions sources included in or excluded from the project boundary

	Source	Gas	Included?	Justification / Explanation
Baseline	Combustion of fossil fuels to produce steam and electricity at the project customers and at the grid	CO_2	Yes	Main emission source in the combustion of fossil fuels.
		CH_4	No	Excluded for simplification.
		N_2O	No	Excluded for simplification.
Project Activity	Combustion of fossil fuels to produce steam and electricity at the project facility(s)	CO2	Yes	Main emission source in the combustion of fossil fuels.
		CH_4	No	Excluded for simplification.
		N_2O	No	Excluded for simplification.

According to version 03 of AM0048, the project boundary will include site of SE "Tirotex" as well as sites of other project customers that will buy electricity from the project cogeneration plant. Project boundary also covers power sources of the baseline scenario: Moldovian TPP producing electricity for SE "Tirotex", and the grid where other project customers are buying electricity in the baseline scenario. (see fig.B.3-1).

Project lifetime is 20 years.

For the purpose of determining *baseline emissions*, project boundary includes the following emission sources:

- CO2 emissions from the combustion of fossil fuel (natural gas) to produce steam at the SE "Tirotex";
- CO2 emissions from electricity production at the Moldovian TPP;
- CO2 emissions from production (in the grid) of electricity used by other project customers, that will be replaced by power produced at CHPP

For the purpose of determining *project emissions*, the project boundary includes:

- CO2 emissions from the combustion of fossil fuel to produce steam and electricity at the CHPP.

The *spatial extent* of the project boundary comprises:

• All equipment installed and used as part of the project for steam and power cogeneration.

• Power production connected to the electricity grid, and the project customer supply power to the grid.

Heat energy (hot water) is excluded from project boundaries.

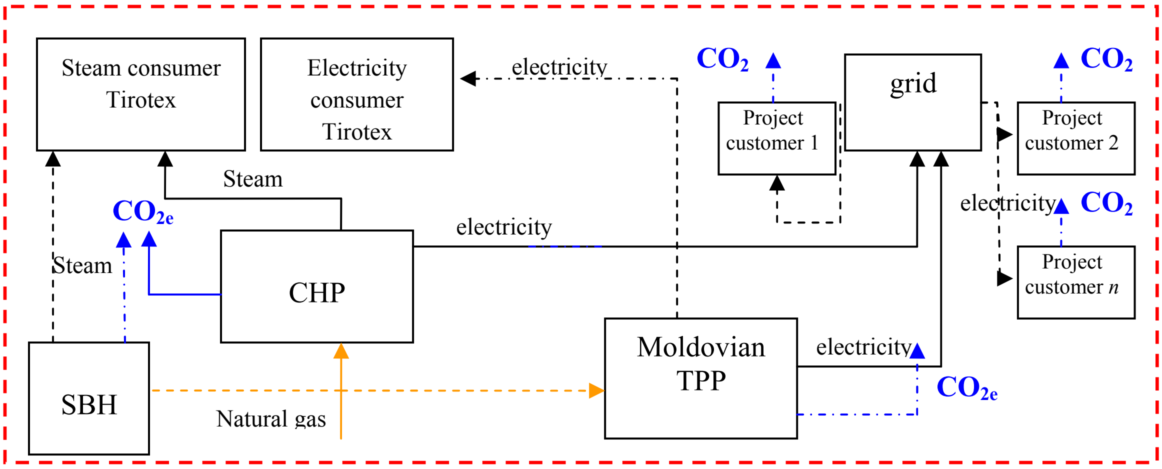

Figure B.3-1. Project boundaries.

- - - - - baseline scenario

_______ project scenario

B.4. Description of how the <u>baseline scenario</u> is identified and description of the identified baseline scenario:

According to the selected methodology version 03 of AM0048 the following steps were used to choose the baseline scenario:

Step 1.Identification of alternative scenarios

According to version 03 of AM0048 different scenarios to be considered and their consequences are given in Table B.4-1.

Table B.4-1 Scenarios elements to be considered

Alternative		Project developer Project facilities in the absence of the project activity (CDM)	Project customer Electricity and/or heat sources in the absence of the project activity (CDM)	Remarks
historical	**1**	No project facility.	Project customer maintains historical characteristics in terms of on-site fuel choice, on-site equipment efficiency, mix of on-site generation and grid purchase (on-site generation capped at self-generation capacity) and on-site generation equipment lifetime (must be greater than the crediting period).	**Applicable**
Fuel choice is likely to change at the project customers in the absence of the project activity	**2a***	No project facility.	Project customer is likely to switch to less intensive GHG fuel in the absence of the project activity	**Not applicable**
	2b*	No project facility.	Project customer is likely to switch to more intensive GHG fuel in the absence of the project activity	**Not applicable**
Efficiency is likely to change at the project customers in the absence of the project activity.	3a	No project facility.	Project customer is likely to increase efficiency of its off-grid electricity/steam production in the absence of the project activity (e.g. replacement of boilers, installation of cogeneration equipment, in absence of the project activity).	**Applicable**, as the boilers at steam boiler house have low efficiency (90%). It's possible to replace existing steam boiler house by new one with efficiency of boilers 96% (with economizer)
	3b	No project facility.	Project customer is likely to decrease efficiency of its off-grid electricity/steam production in the absence of the project activity.	**Applicable**, with time the existing boilers will get ageing effect that will lead to natural decrease of efficiency.
Energy consumption	4	No project facility.	Project customer energy (electricity and/or heat)	**Not applicable**, SE "Tirotex" had

of project customer is likely to change in the absence of the project activity			consumption in the baseline scenario is likely to be different from that of the project scenario.	stable consumption of energy resources during last 4 years
Project customer is likely to be supplied by **external sources of electricity/heat** in the absence of the project activity	**5**	Proposed project activity without the CDM or other external sources of electricity/heat supply the project customers energy demands.	Project customer is likely to be supplied by external sources of electricity/heat in the baseline scenario.	**Not applicable**, the project customer (SE "Tirotex") consumes the steam from own facility and electricity from the grid in absence of the project activity

Note:

*2a

- For **hydro energy** – it's excluded from consideration due to geographical location of the site.

- For **wind and solar**, the intermittent nature of electricity generated by wind/solar power means that it could not supply a similar service to the proposed project

- **Biomass** as a source of energy in the Republic of Moldova participates in the total energy balance with ca. 3,6%[1]. But it is used only as wood for heating and it is a primary resource for heating in the households. Studies show that the waste wood mass from the woods and agriculture has an important potential (planned to replace up to 10% of total energy consumed), but only 114 TJ[1] were available in 2006 that's could cover only 6% of the fuel need. Now 2 small scale CDM project is implemented in the Republic of Moldova. Due to this fact it is currently not economically justified to use this biomass for the production of electricity within the country.

- In Moldova farms keeping small capacities of livestock prevail, hence the production of **biogas** and its use for production of electricity and its use for production of electricity does not have economical justification. Even if it would get conducted, the capacity of the power plant would be negligible considering the needs for electricity in the country.

*2b

Mazut steam turbine power unit: This alternative is unlikely due to low economic performance caused by high price of residual fuel oil, which is approximately 1.4 times higher than the price of natural gas as converted to energy units, and low efficiency of power unit as compared with combine-cycle power unit.

Coal fired power plant is excluded: this alternative has disadvantage as high investment costs – that's is ca 2,5 higher[2] than for gas reciprocating engine CHPP. Another problem is necessity in a big storage yard and development of infrastructure.

All the identified alternatives envisage several baseline scenario options, which could ensure power supply based on components considered in the methodology AM 0048 (see Table B.4-1).

Alternative 1:

Replacement of the old gas fired steam boilers by new gas fired steam boilers with higher efficiency

Alternative 2:

[1] Fuel and energy balance of the Republic of Moldova for 1999-2006. Statistic report. http://www.statistica.md/

[2] Hoskins Bill, Booras George. "Assessing the cost of new coal-fired power plants." Power, Vol 149. Issue 8, Oct. 2005

Continuation of the existing situation: steam is produced at the existing boiler house; boilers have regular maintenance and reduction of the efficiency due to aging effect.

Alternative 3:
Construction of CHPP on the base of gas reciprocating gensets without CDM impact

Additionality
Additionality is demonstrated using the version 05.2 of the "Tool for the demonstration and assessment of additionality".

Step 1. Identification of alternatives to the project activity consistent with current laws and regulations
Sub-step 1a: Define alternatives to the project activity:

As the Project includes different technologies (both power and steam production), the separately alternatives for power and steam are described below:
Steam:
Alternative 1S:
All steam for own needs of the enterprise is generated by new gas fired boilers with higher efficiency.
Alternative 2S:
Steam is produced at the existing boiler house.
Alternative 3S:
Steam is generated in new steam recovery boilers, which are the part of new cogeneration plant.

Power:
Alternative 1P:
Electricity for own needs of the enterprise will be purchased from the grid.

Alternative 2P:
Electricity will be generated at the project site using new cogeneration blocks.

The identification of the most realistic and credible alternatives for power and steam generation is presented in the section B.4 above and the formation of "combined alternatives" is presented there as well.
Below the short description of the alternatives is presented.

Alternative 1:
Replacement of the old gas fired steam boilers by new gas fired steam boilers with higher efficiency

Alternative 2:
Continuation of the existing situation: steam is produced at the existing boiler house; boilers have regular maintenance and reduction of the efficiency due to aging effect.

Alternative 3:
Construction of CHPP on the base of gas reciprocating gensets without CDM impact

Sub-step 1b: Consistency with mandatory laws and regulations:

There are some laws on electricity sector acting in the Republic of Moldova: Law on electrical energy (137-XIV of 17.09.1998), Law on energy sector (1525-XIII of 19.02.1998). However, these laws are not applied to The Republic of Moldova where the project site is physically located.
The legislation for the power sector of The Republic of Moldova is currently under preparation: a draft law on electricity is under consideration in the parliament The Republic of Moldova where rules, tariffs of the connecting to the grid or transmission /distribution /generation/ consumption of the

electricity will be set up. The rules for cogeneration are also to be covered by this law. Currently there are no laws that will stimulate co-generation activities within the country as well as there is no obligation for the grid to accept the electricity produced at a private CHPP.

Thus, all identified alternatives are consistent with law of PMR and mandatory regulations in force.

Step 2. Investment analysis:

Sub-step 2a: Determine appropriate analysis method

Project participants decided to apply investment comparison analysis (Option II). This project envisages obtaining revenue from electricity sales in addition to CER sales. Therefore, simple cost analysis (Option I) cannot be applied. This means that either investment comparison analysis (Option II) or benchmark analysis (Option III) should be applied. Option III can't be used because of absence of official publicly available financial data and comparable projects.

Sub-step 2b: Option II. Apply investment comparison analysis

Preliminary the Interest Rate of Return, as a suitable financial indicator for the proposed activity not being registered as CDM was calculated (A3). All relevant data required for such calculations (like investment costs, operating costs, revenues, tariffs, etc) and the calculations are presented in the Annexes 3.5-3.10[3]. The results of the investment comparison analysis are presented in the table B.4-2a below:

Table B.4-2a – Investment analysis

Alternative	IRR,%
A3 CHPP	2.4

Prices, tariffs and operational costs (wages, maintenance costs) were based on the following data:

Questionnaire of the enterprise (see Annex 3-13);

Business-plan for construction of CHPP (provided to AIE);

Available national data (currency exchange rate, etc.).

Financial indicators were calculated for 20-year period (project lifetime) (Annexes 3.5-3.10).

However, such indicator as IRR can't be calculated for the Alternative 2 (current situation) because of absence of investment costs. So, the levelized prime cost of thermal and power energy was chosen for the comparison of financial appeal. Specific prime costs of thermal and power energy are shown in the table B.4-2b:

Table B.4-2b – Costs of heat and electricity

	Alternative 3
Electricity cost	18.15
Heat energy cost	51.86

According to Version 03 of AM0048, the economically most attractive baseline scenario alternative is identified using levelized cost as a financial indicator. The levelized cost is therefore calculated for the alternatives identified above (see Table B.4-2).

The formula applied to calculate the levelized heat and power generation cost (LHC and LPC) is the following:

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[3] To be conservative a discount rate of 10% was assumed for all calculations based on an interest rate offered to a legal entity for the period when the decision of the project implementation was done (http://www.cbpmr.net/resource/stavdepozyanv.pdf, http://www.bnm.md/en/ratele_medii_dobanzilor)

$$LHC = \frac{\sum_{t=1}^{n} (I_t + M_t + F_t)/(1+r)^t}{\sum_{t=1}^{n} H_t /(1+r)^t} \quad \text{(B.6-5a)}$$

$$LPC = \frac{\sum_{t=1}^{n} (I_t + M_t + F_t)/(1+r)^t}{\sum_{t=1}^{n} P_t /(1+r)^t} \quad \text{(B.6-5b)}$$

where I_t is the capital costs in the year *y*, EUR;
M_t is the operational and maintenance costs in the year *y*, EUR;
F_t is the fuel costs in the year *y*, EUR;
H_t is the net heat generation in the year *y*, Gcal;
P_t is the net heat generation in the year *y*, Gcal;
n is the lifetime of the proposed system, years;
r is the discount rate, %.

Sub-step 2c: Calculation and comparison of financial indicators (only applicable to Options II and III)

In case of comparison of Alternatives 1 and 2 with Alternative 3 the following figures were obtained:

Table B.4-2c – Investment comparison analysis

Alternative	IRR,%
A1 New steam boilers	-
A2 Old steam boilers	-
A3 CHPP	2.4

Table B.4-2d – Costs of heat and electricity

	Alternative 1	Alternative 2	Alternative 3
Electricity cost	38.46	38.46	18.15
Heat energy cost	20.49	17.22	51.86

All relevant costs including investment costs, operational and maintenance costs and revenues are presented in the Annexes 3.5-3.10.

Obviously, comparison of NPV and IRR are not appropriate indicators for the project, because they can't be calculated for A1 and A2.

Levelized costs of power and heat energy also can't be considered as unambiguous indicators. LHC is the most costly for project scenario, but LPC is the lowest among all alternatives. It can be explained by the fact that we compare *prime cost* for alternative 3 with *final cost* for alternatives 1 and 2 (cost of grid electricity). But in the project scenario a part of produced power will be sold to the grid; in this case very low prime cost of electricity can't be considered as most financially attractive. But, for more clarity step 3 also can be used in such case.

Sub-step 2d: sensitivity analysis (only applicable to Options II and III)

Table B.4-3. Sensitivity Analysis to fluctuation of fuel costs

Fluctuation	**-10%**	**-5%**	**0**	**5%**	**10%**

of gas prices					
LHC, (EUR/Gcal)					
Alternative 1	20.49	20.49	20.49	20.49	20.49
Alternative 2	15.70	16.46	17.22	17.99	18.75
Alternative 3	48.74	50.30	51.86	53.42	54.99
LPC, (EUR/MWh)					
Alternative 1	38.46	38.46	38.46	38.46	38.46
Alternative 2	38.46	38.46	38.46	38.46	38.46
Alternative 3	17.06	17.61	18.15	18.70	19.25
Fluctuation of investment costs	**-10%**	**-5%**	**0**	**5%**	**10%**
LHC, (EUR/Gcal)					
Alternative 1	20.49	20.49	20.49	20.49	20.49
Alternative 2	17.22	17.22	17.22	17.22	17.22
Alternative 3	50.63	51.25	51.86	52.47	53.09
LPC, (EUR/MWh)					
Alternative 1	38.46	38.46	38.46	38.46	38.46
Alternative 2	38.46	38.46	38.46	38.46	38.46
Alternative 3	17.73	17.94	18.15	18.37	18.58
Fluctuation of operation costs	**-10%**	**-5%**	**0**	**5%**	**10%**
LHC, (EUR/Gcal)					
Alternative 1	20.49	20.49	20.49	20.49	20.49
Alternative 2	15.50	16.36	17.22	18.09	18.95
Alternative 3	47.90	49.88	51.86	53.84	55.82
LPC, (EUR/MWh)					
Alternative 1	38.46	38.46	38.46	38.46	38.46
Alternative 2	38.46	38.46	38.46	38.46	38.46
Alternative 3	16.77	17.46	18.15	18.85	19.54
Fluctuation of power tariff	**-10%**	**-5%**	**0**	**5%**	**10%**
LHC, (EUR/Gcal)					
Alternative 1	20.49	20.49	20.49	20.49	20.49
Alternative 2	17.22	17.22	17.22	17.23	17.23
Alternative 3	51.74	51.80	51.86	51.92	51.98
LPC, (EUR/MWh)					
Alternative 1	34.61	36.53	38.46	40.38	42.30
Alternative 2	34.61	36.53	38.46	40.38	42.30
Alternative 3	18.11	18.13	18.15	18.18	18.20

Summarizing the results of the above analysis (see Annex 3.8), after comparison of the LHC for different alternatives it can be seen that this value is lowest for Alternative 2: "Operation of the existing boiler house", thus Alternative 2 is chosen as <u>the most plausible baseline scenario</u>.

As the results of the table B.4-2d the most attractive is Alternative 2 and without CDM impact Alternative 3 hardly could be considered as an attractive investment choice (table B.4-3)

In the table and on the picture below, the IRR of the Project scenario is shown (with and without CDM income).

Discount rate	10,0%
IRR without CERs sales	2,4%
IRR with CERs sales	4,8%

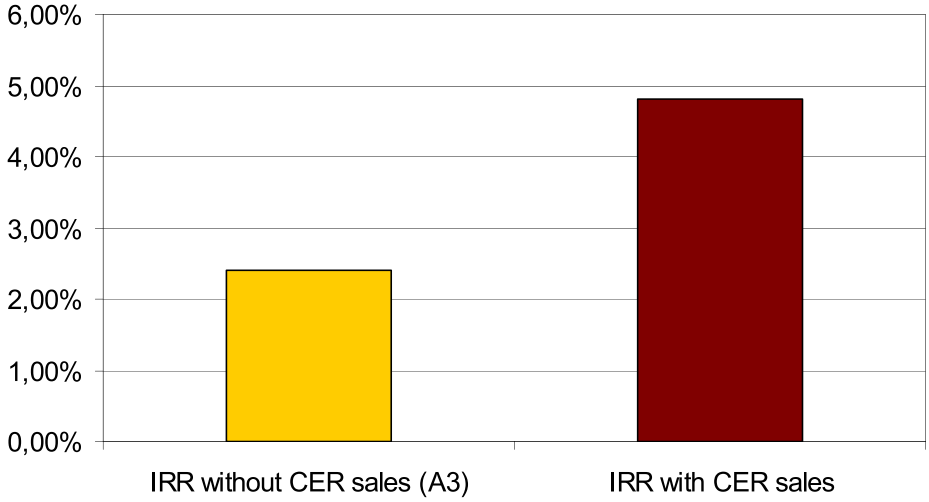

Figure B.4-1. Influence of CDM impact.

Economic parameters of the project without CDM mechanism are sufficiently lowest in comparison with project with CER incomes. Revenues received from CERs sale during the first crediting period are making about 20.42% of the total amount of investments, during the second and third crediting periods – about 41.03%. These funds will help to significantly improve commercial attractiveness of the project and NPV becomes positive. Moreover, the project becomes less sensitive to risks (see the results of sensitivity analysis in Table B.4-4).

Table B.4-4. Sensitivity Analysis of economic parameters of the project scenario

Indicator	**Unit**	**Project activity with CDM impact**	**Project activity w/o CDM impact**
Increase of investment costs by 5%			
IRR	%	5.0	2.3
Reduction of heat and electricity generation by 5%			
IRR	%	3.4	0.5
Increase of fuel costs by 5%			
IRR	%	3.4	0.6

Thus, the project can not be implemented under common commercial practice without selling CERs

Step 3. Barrier analysis

Investment barrier:

The enterprise doesn't have own assets to cover all investment costs. This is **very important barrier**. Loan investments are 66.5% of total investments to the project and it is about 15 mill. Euro. Taking into consideration a very low IRR of the project without CDM impact, it is impossible to get such credit without revenues from CER sales.

Also there are some investment risks could be associated with the project, such as not high crediting rating of Moldova (Fitch Ratings: http://www.fitchratings.ru/regional/country/news/newsrelease/news.wbp?article-id=E464A833-3289-4498-88FE-61B826009308).

Also taking into account the low financial attractiveness of the project there is not private capital available from domestic or international capital markets.

Alternative 2 doesn't faces such barrier because this alternative doesn't requires any significant investments. According to the Additionality Tool this barrier makes **the project additional.**

Technological barriers: The construction of the cogeneration plant based on the gas reciprocating engines is the first in the country. There are no specialists experienced with operation of such technology.

CHP plants that already exist in the country has different technology – steam turbine cycle.

Another barrier on the way is that fact that in The Republic of Moldova the volumes of the natural gas (NG) consumption are set up for each big consumer and SE Tirotex should receive the increased volumes of NG for new CHPP operation that increases the risks of the project for an investor. In a case of the other two alternatives that amount of natural gas consumption will not be higher than the current one.

Barriers due to prevailing practice:

In the Republic of Moldova there are the following sources to generate electricity:

a) Thermo-Electrical Power Plant with condensation – Moldovian TPP
b) Cogeneration Plants – CHP-1 and CHP-2 Chisinau and CHP-North Balti
c) Hydroelectric plants – Costesti and Dubasari

a) Moldovian TPP

Moldovian TPP was constructed in the period 1964-1980 and consists of 12 energy units with the total installed capacity of 2520MW, the available capacity is 950MW. The main fuel for units 11 and 12 is the NG for units 9 and 10 – residual fuel oil, the coal is the design fuel for the units 1-8. The wear degree of the equipment varies from about 80% for units 1-8 which were put into operation during the years 1964-1971 (during the period 1998-2002 none of them functioned, all of them are currently out of operation). The wear degree of the units 9-12 which were built during 1974-1980 is estimated at about 50%.

b) CHPs

CHP-1 in Chisinau was constructed in the period 1976-1980. It has an installed capacity of 210 MW, while technically available capacity is 56 MW. The main fuel is NG, and the reserve one is residual fuel oil (mazut). The wear degree of the equipment is about 60%

CHP-2 in Chisinau with the installed capacity of 240 MW and available capacity of 50MW was constructed in the period of 1951-1961. The main fuel is NG, and the reserve one is residual fuel oil (mazut). The wear degree of the equipment is about 50%.

CHP North Balti was constructed in 1960. It has an installed capacity of 28 MW, the available of 24 MW. The main fuel is NG, and the reserve one is residual fuel oil (mazut). The wear degree of the equipment is about 60%.

The CHPs of the sugar factories with a total capacity of about 90 MW serve as seasonal energy sources (Alexandreni – 12 MW, Briceni – 12 MW, Cupcini – 12 MW, Donduceni – 10MW, Drochia – 10MW, Falesti -7,5 MW, Garbova – 12 MW, Ghindesti – 6MW, Glodeni – 10MW). These CHPs were put into operation between the years of 1956-1985, so that their degree of wear differs from one station to another. The installed capacity of these CHPs depends on the volume of production of sugar, being estimated at about 20MW. These plants usually are operated during the sugar-beet processing season (3-4 months per year), consuming for self use about 60-90% of the electricity produced.

c) hydro-electrical plants (HPP)

The hydro-electrical power plants from Dubasari was put into operation in 1954, having an installed capacity of 48 MW, an available capacity of 30MW and a wear degree of about 75%.

The hydro-electrical power plants from Costesti had a installed capacity of 16MW, the available capacity being of about 10MW and the wear degree of 67%. It was put into operation in 1978.

The situation in the power sector shows that all available electricity generation capacities were built before 1991 and are out of date with low efficiency. There are no incentives to build a new efficient co-generation plant within the country as for the last 18 years no new units has been built.

As the project is the first one that uses the co-generation technology based on gas-reciprocating engines the owners of the CHPP have started procedure of the approval of the project as innovative one. so that this project will be officially recognised as "first-of-its kind" in the country.

Legislative barrier:

There are some laws on electricity sector acting in the Republic of Moldova: Law on electrical energy (137-XIV of 17.09.1998), Law on energy sector (1525-XIII of 19.02.1998). However, these laws are not applied to The Republic of Moldova where the project site is physically located.

Currently in The Republic of Moldova only a draft law on electricity is under consideration in the parliament of The Republic of Moldova where rules, tariffs of the connecting to the grid or transmission/distribution/generation/consumption of the electricity will be set up. Currently there are no laws that will stimulate co-generation activities within the country as well as there is no obligation for the grid to accept the electricity produced at a private CHPP. All CHPs that are operated in the country were built before 1991 (see annex 3-2).

Implementation of the Alternative 1 and 2 is a common practice in the country and meet no barriers mentioned above.[4]

Step 4. Common practice analysis

Tables B.4-4 contains data on net electricity generation at the power plants connected to the power grid of the Republic of Moldova over the period of 1990-2000. Basic scheme of power grid in the Republic of Moldova is presented in Annex 3-1.

Table B.4-4. Net electricity generation at power plants connected to the power grid of the Republic of Moldova over the period of 1990-2000, GWh

Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
CHP-1	207	207	196	150	136	106	115	93	119	115	60
CHP-2	1,311	1,106	1,074	1,020	880	794	960	1.057	894	801	800
CHP-North	121	100	102	85	87	80	100	96	84	51	20
Sugar Factories CHPs	176	164	146	129	84	112	134	114	92	73	80
HPP Costesti	37	71	60	66	46	84	87	84	54	91	85
Moldovan TPP	13,569	11,222	9,468	8,626	6,836	4,474	4,560	3,639	2,974	2,454	2,334
HPP Dubasari	220	227	198	308	232	239	279	295	224	284	256
Other sources	31	49	13	2	0	0	4	3	3	6	5
Total on the country	15,972	13,146	11,257	10,386	8,301	6,162	6,239	5,381	4,444	3,875	3,640

[4] Technology needs and development. Chisinau 2002.

All the electricity production sources were built more than 40 years ago and are inefficient comparing to the current technologies.[3]

The energy system of Moldova has no combined heat and power plants based on gas reciprocating engines until now.

Sub-steps b: Discuss any similar options that are occurring

According to Tables B.4-4 and analysis in Step 3 the project activity is not common practice in Moldova and there are no similar technology activities to the proposed project activity.

In the result of investigation conducted in B.4, it can be concluded that the baseline scenario is a continuation of current situation: steam production in old boiler-house and electricity purchase from the grid.

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

AM0048 requires that the “Tool for the demonstration and assessment of additionality” is used. Therefore, please refer to the section above where the additionality has been determined. Justification of key assumptions and rationales also was indicated in B.4. All the data used to determine the baseline scenario also are indicated in section B.4 and in the documents provided by the Enterprise.

This project consists of the construction of an efficient, gas-fired 31 MW CHPP at large industrial textile enterprise SE “Tirotex” in Tiraspol city. The CHPP will replace the existing boiler-house providing heat and steam for technological and heating needs of the enterprise and will deliver electricity to the SE “Tirotex” and other consumers in the grid.

The incentive from CDM was seriously considered in the decision to proceed with the project activity. It can be proved by the note from the bank “Comertbank” S.A., which stipulate that SE “Tirotex” can’t obtain the credit for CHPP construction without CDM component of the project. Own assets of SE “Tirotex” are not enough for CHPP construction and financial indicators of the Project without CERs selling are not attractive for banks.

Currently SE “Tirotex” including the boiler-house is consuming electricity from the Moldovian TPP, which has electricity emission factor is higher than new CHPP will have.

This project aims to put into operation cogeneration units that will provide energy to the project customer and supply the rest of electricity to the grid.

In a case of realization of the Alternative 1 the possible savings would be in around 3 mln. nm^3 of natural gas that is ca. 6 000 t CO_2e per year (See Annex 3.4 and 3.4)

The project activity will help to reduce greenhouse gas emissions in the following ways:

1. It will replace the electricity currently supplied to SE “Tirotex” by the Moldovian TPP and being produced in a less efficient way.
2. It will displace the electricity currently supplied to other project customers from the local electricity grid produced in a less efficient way.
3. It will decrease total fuel consumption through separate generation of electricity and heat.
4. It will lead to reduction of losses in the power grid due to its delivery.

As shown in the paragraph above B.4 the reductions obtained as a result of the project will be additional to any that would otherwise occur.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

According to the methodology "**New cogeneration facilities supplying electricity and/or steam to multiple customers and displacing grid/off-grid steam and electricity generation with more carbon-intensive fuels**" version 03 of AM0048, the emission reductions can be calculated using the following steps:

Under the project facility is assumed the new CHPP.

Step 1. Calculation of the baseline emissions

The baseline emissions are sum of emissions from generation of electricity and emissions from generation of steam:

$$BE_y = BE_{IC,y} + BE_{ST,y} + BE_{GR,,y} \quad \text{(B.6-1)}$$

Where:

BE_y – Baseline emissions in year 'y' (tCO_2).

$BE_{IC,y}$ – Emissions for the production of electricity that would be supplied to the project customer (SE Tirotex and other project customers) in year 'y' in the baseline scenario (tCO_2).

$BE_{ST,y}$ – Emissions for the production of steam that would be supplied to the project customer (SE Tirotex) in year 'y' in the baseline scenario (tCO_2).

$BE_{GR,y}$ – Emissions for the production of electricity that would be supplied to the grid in year 'y' in the baseline scenario (tCO_2).

Emissions for the production of electricity $BE_{IC,y}$ that would be supplied to the project customer in year 'y' in the baseline scenario:

$$BE_{IC,y} = \sum_j (EL_{BL,j,iy} \cdot EEF_{BL,iy}) \quad \text{(B.6-2)}$$

Where:

$EL_{BL,j,,y}$ – Electricity consumed by the project customer from the proposed project facility 'j' in year 'y' eligible to certified emissions reductions (MWh).

$EEF_{BL,,y}$ – Baseline CO2 emission factor for electricity of the project customer in year 'y' (tCO_2/MWh).

$$EL_{BL\ j,y} = min(EL_{PJ,j,,y}, EL_{MG,} - EL_{PCSG,y}) = EL_{PJ,j,,y} \quad \text{(B.6-3)}$$

Where:

$EL_{PJ,j,y}$ – Electricity purchased by the project customer from the proposed project facility 'j' in year 'y' (MWh). Measured at the project facility and/or at the project customer.

EL_{MGi} –Total historical capacity of electricity generation of equipment existing at project customer 'i' previous to the implementation of the project activity (MWh). (excluded from calculation due to the fact that electricity in the baseline is not self-generated by the project customer)

$EL_{PCSG,y}$ –Total electricity self-generated by project customer 'i' during year 'y' of the crediting period (MWh). Measured at the project customer (excluded from calculation due to the fact that electricity in the baseline is not self-generated by the project customer)

The baseline CO2 emission factor for electricity of the project customer is obtained from the National DFP of the Republic of Moldova and for the first crediting period equals:

$$EEF_{BL,,y} = 0{,}4224 \ \ tCO2/MWh_{el} \quad \text{(B.6-4)}$$

Emissions for the production of steam $BE_{ST,y}$ that would be supplied to the project customers in year 'y' in the baseline scenario

It is assumed that steam is produced at constant temperature and pressure.

$$BE_{ST,y} = \sum_{j} (SC_{BL,j,y} \cdot SEF_{BL,y}) \qquad \text{(B.6-5)}$$

Where:
$SC_{BL,j,y}$ – Steam consumed by the project customer from the proposed project facility 'j' in year 'y' eligible to certified emissions reductions (TJ).
$SEF_{BL,y}$ – Baseline CO_2 emission factor for steam of the project customer in year 'y' (tCO2/TJ).

The steam eligible to certified emissions reductions is limited to the maximum generating capacity of the project customer existing previous to the implementation of the project activity:

$$SC_{BL,j,y} = \min (SC_{PJ,y} , SC_{MG} - SC_{PCSG,y}) \qquad \text{(B.6-6)}$$

Where:
$SC_{PJ,j,y}$ – Steam purchased by the project customer from the proposed project facility 'j' in year 'y' (TJ).
SC_{MG} – Total historical capacity of steam generation of the equipment existing at project customer previous to the implementation of the project activity (TJ).
$SC_{PCSG,y}$ – Total steam self-generated by project customer during year 'y' of the crediting period (MWh). Measured at the project customer.

The steam purchased by the project customer from the proposed project facility 'j' in year 'y' is calculated as:

$$S_{PJ,j,y} = S_{PJ,j,y} \cdot EN_{PJ} \qquad \text{(B.6-7)}$$

Where:
$S_{PJ,j,y}$ – Steam purchased by the project customer from the proposed project facility 'j' in year 'y' (tonnes). Measured at the project facility 'j' and/or at the project customer.
EN_{PJ} – Specific enthalpy of the steam purchased by the project customer (TJ/tonnes). This data are obtained from steam tables, using temperature and pressure of the steam purchased measured at the project customer.
The maximum generation capacity of steam of the pre-project generating equipment is calculated as:

$$SC_{MG} = (\sum_{m} GC_{ST,m} \cdot (8760 - MDH_{ST,i,m}) \cdot EN_{BL,m}) / J_{ST,y} \qquad \text{(B.6-8)}$$

Where:
$GC_{ST,m}$ – Nameplate capacity of the steam generating equipment 'm' existing at project customer previous to the implementation of the project activity (tonnes/hour). Obtained from the project customer.
$MDH_{ST,m}$ – Normal maintenance and down time hour of the generation equipment 'm' existing at project customer previous to the implementation of the project activity (hour). Obtained from the project customer.
$EN_{BL,m}$ – Specific enthalpy of steam of the pre-project generating equipment 'm' of project customer (TJ/tonnes). This data are obtained from steam tables, using temperature and pressure of the steam measured at the pre-project generating equipment of project customer.
$J_{ST,y}$ – Number of project facilities 'j' supplying steam to the project customer, in year 'y', simultaneously (number). Obtained from the project customer.

The baseline emission factor for self-generated steam $EF_{BL,ST,j,y}$ shall be calculated as:

$$SEF_{BL} = ((CEF \cdot FC_{ST})) / HG_{ST,m} \qquad \text{(B.6-9)}$$

Where:

CEF – Carbon emission factor of natural gas used by project customer to self-generate steam in the baseline scenario (tCO2/TJ). IPCC default value.

FC_{ST} – Consumption of natural gas by project customer to self-generate steam in the baseline scenario (TJ).

HG_{ST} – Steam self-generated by project customer with natural gas in the baseline scenario (TJ).

The steam self-generated by project customer with NG in the baseline scenario is:

$$HG_{ST} = H_{ST} \cdot EN_{BL} \qquad \text{(B.6-10)}$$

Where:

H_{ST} – Steam self-generated by project customer with NG during the most recent three years previous to the implementation of the project activity (tonnes). Obtained from the project customer.

The consumption of NG by the project customer to self-generate steam in the baseline scenario is calculated as:

$$FC_{ST} = F_{ST} \cdot NCV \qquad \text{(B.6-11)}$$

Where:

F_{ST} – Amount of NG used by project customer to self-generate steam during the most recent three years previous to the implementation of the project activity (mass or volume units). Obtained from the project customer.

NCV – Net calorific value of NG at the project customer in the baseline scenario (TJ/nm^3). Obtained from the project customer.

Emissions for the production of electricity $BE_{GR,y}$ that would be supplied to the grid in year 'y' in the baseline scenario:

$$BE_{GR,y} = \sum_{j} EL_{PF,GR,j,y} \cdot EF_{PF,GR,j,y} \qquad \text{(B.6-12)}$$

Where:

$EL_{PF,GR,j,y}$ – Electricity supplied to the grid and/or to distribution entities by the proposed project facility 'j' in year 'y' (MWh);

$EF_{PF,GR,j,y}$ – CO_2 emission factor for the grid electricity connected to the project facility 'j' and/or to the distribution entities in year 'y' (tCO_2/MWh). This grid emission factor is obtained from National DFP of the Republic of Moldova and for the first crediting period equals $EF_{PF,GR,j,y}$ = 0,4224 t CO2/$MWh_{el.}$

The emission factor is estimated using the procedure described in the latest version of approved "Tool to calculate emission factor for an electricity system" making $EF_{GR,PF,j,y} = EF_y = EEF_{BL,,y}$

Step 2. Calculation of the leakages

Leakage may result from the extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary. This includes mainly fugitive CH4 emissions and CO2 emissions from associated fuel combustion and flaring. In accordance with the methodology version 03 of AM0048 the following leakage emission sources shall be considered:

Fugitive CH4 emissions associated with the extraction, processing, liquefaction, transportation, regasification and distribution of fossil fuels used in the project plant and fossil fuels used in the grid in the absence of the project activity.

$$LE_y = LE_{CH4,y} + LE_{LNG,CO2,y} \qquad \text{(B.6-13)}$$

Where:

LE_y – Leakage emissions (tCO_2).

$LE_{CH4,y}$ – Leakage emissions due to fugitive upstream CH_4 emissions in the year 'y' (tCO_2).

$LE_{LNG,CO2,y}$ – Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into natural gas transmission or distribution system during the year 'y' of the crediting period (tCO_2).

Fugitive methane emissions $LE_{CH4,y}$

For the purpose of determining fugitive methane emissions associated in case of natural gas with the transportation and distribution of the fuel used the next formulae:

$$LE_{CH4,y} = \cdot GWP_{CH4} \cdot \sum_j (FC_{PJ,PF,j,y} \cdot NCV \cdot EF_{CH4,ups}) \qquad \text{(B.6-14)}$$

Where:

GWP_{CH4} – Global warming potential of CH4 (tCO_2/tCH_4) valid for the commitment period. Obtained from IPCC default values.

$EF_{CH4,ups,k}$ – Emission factor for upstream fugitive methane emissions from production, transportation and distribution of fuel 'k' (tCH_4/TJ). Taken from version 03 of AM0048 (0.528)

CO_2 emissions from LNG $LE_{LNG,CO2,y}$ are not accounted in the project as it's foreseen usage of NG without liquefaction.

Step 3. Calculation of the project emissions

The project activity is on-site combustion of natural gas to generate electricity. Steam and heat will be generated by utilizing waste heat without additional combustion of fossil fuel. GHG emissions from natural gas combustion are calculated as follows:

$$PE_y = \frac{44}{12} \cdot \sum_j \sum_k \left(FC_{PJ,PF,j,k,y} \cdot NCV_{j,k} \cdot CEF_{j,k} \right) \qquad \text{(B.6-15)}$$

Where:

PE_y – Project activity emissions (tCO_2).

$FC_{PJ,PF,y}$ – Quantity of NG consumed (nm^3) in the year 'y' in the project facilities 'j'. Measured at the project facility.

NCV – Net calorific value of NG used at the project facility during the crediting period (TJ/nm3). Obtained from the project customer.

CEF – Carbon emission factor of NG used by project facility during year 'y' of the crediting period (tC/TJ). IPCC default value (56.1).

Step 4. Calculation of the emissions reductions

The emission reduction ER y by the project activity during a given year *y* is the difference between the baseline emissions (BE_y) and project emissions (PEy) with leakage emissions, as follows:

$$ER_y = BE_y - PE_y - LE_y \qquad \text{(B.6-16)}$$

Where:

ER_y – Emissions reductions of the project activity during the year y (tCO_{2e})

BE_y – Baseline emissions during the year y (tCO_{2e})

PE_y – Project emissions during the year *y* (tCO_{2e})

LE_y – Leakage emissions during the year *y* (tCO_2e)

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

Data / Parameter:	*ELGR*
Data unit:	MWh
Description:	Total amount of electricity obtained from the grid by project customer during the most recent three years previous to the implementation of the project activity. Obtained from the project customer
Source of data used:	Electricity data log available at project customer site.
Value applied:	Average value for the last 3 years: 128 116
Justification of the choice of data or description of measurement methods and procedures actually applied :	Store information until 2 years after the end of the crediting period.
Any comment:	-

Data / Parameter:	*ENBL, and ENBL,,m*
Data unit:	kJ/kg
Description:	Specific enthalpy of steam of generating equipment existing at the project customer previous to the implementation of the project activity. This data are obtained from steam tables, using temperature and pressure of the steam measured at the pre-project generating equipment of project customer
Source of data used:	Steam tables
Value applied:	2787.79
Justification of the choice of data or description of measurement methods and procedures actually applied :	Use monitored pressure and temperature of the steam to obtain specific enthalpy from steam tables. Store information until 2 years after the end of the crediting period. http://www.dpva.ru/informations/Mtls/Gases/Steam/SaturatedSteam0to100bar/
Any comment:	-

Data / Parameter:	*Steam temperature*
Data unit:	oC
Description:	Temperature of steam purchased by project customer
Source of data used:	Temperature meters at project customer
Value applied:	197
Justification of the choice of data or description of measurement methods and procedures actually applied :	Read temperature meter daily and calculate monthly average. Store information until 2 years after the end of the crediting period.
Any comment:	-

Data / Parameter:	*Steam pressure*
Data unit:	Bar
Description:	Pressure of steam purchased by project customer
Source of data used:	Pressure meters at project customer
Value applied:	14

Justification of the choice of data or description of measurement methods and procedures actually applied :	Read pressure meter daily and calculate monthly average. Store information until 2 years after the end of the crediting period.
Any comment:	-

Data / Parameter:	*FST specify)*
Data unit:	nm3
Description:	Consumption of NG by project customer to self-generate steam during the most recent three years previous to the implementation of the project activity. Obtained from the project customer
Source of data used:	Fuel data log/purchase receipts available at project customer site
Value applied:	27 193 000
Justification of the choice of data or description of measurement methods and procedures actually applied :	Store information until 2 years after the end of the crediting period.
Any comment:	-

Data / Parameter:	*GCST,,m*
Data unit:	Tonnes/hour
Description:	Nameplate capacity of the steam generating equipment ‘m’ existing at the project customer previous to the implementation of the project activity. Obtained from the project customer.
Source of data used:	Equipment at project customer site.
Value applied:	3 boilers GM 50/14 with nameplate capacity 50 t/h and 2 boilers DE-25/14 with nameplate capacity 25 t/h
Justification of the choice of data or description of measurement methods	Read nameplate capacity before project implementation. Store the information until 2 years after the end of the crediting period.

and procedures actually applied :	
Any comment:	-

Data / Parameter:	*MDHST,m*
Data unit:	Hour
Description:	Normal maintenance and down time hour of the steam generating equipment 'm' existing at the project customer previous to the implementation of the project activity.
Source of data used:	Maintenance data log available at project customer site.
Value applied:	150 h for each boiler
Justification of the choice of data or description of measurement methods and procedures actually applied :	Check maintenance data logs. Store information until 2 years after the end of the crediting period.
Any comment:	Check consistency with technical benchmarks and equipment manufacturer data

Data / Parameter:	*HST*
Data unit:	Tonnes
Description:	Steam self-generated by project customer with NG during the most recent three years previous to the implementation of the project activity
Source of data used:	Steam data log available at project customer site.
Value applied:	Average value for the last 3 years: 345 087
Justification of the choice of data or description of measurement methods and procedures actually applied :	Store information until 2 years after the end of the crediting period.
Any comment:	-

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

In accordance within the formulae given in the chapter B-6.1 of the PDD the following ER were calculated:

Coefficients of electricity emission factors are given in the Section B.6.1.

Baseline emissions (formulae B.6-1-B.6-12)

		Unit		2010	2011	2012
BE_y		ths. t CO_2		149046	176860	176860
BE_{IC}		**t CO_2**		**57459**	**57459**	**57459**
	$EL_{PJ,j,I,y}$	MWh		136 030	136 030	136 030
	$EEF_{BLi,y}$	tCO_2/MWh		0.4224	0.4224	0.4224
BE_{GR}		**t CO_2**		**83440**	**111254**	**111254**
	EL_{PF}	MWh		197 539	263 386	263 386
	EEF_{PFGR}	tCO_2/MWh		0.4224	0.4224	0.4224

BE_{ST}				**t CO_2**		**8 147**	**8 147**	**8 147**
	SC_{BL}			TJ		152	152	152
		SC_{PJ}				377	502	502
			S_{PJ}	t		135872	181163	181163
			EN_{PJ}	TJ/t		0.00277	0.00277	0.00277
		SC_{PCSG}		TJ		808	808	808
		SC_{PCSG}		MWh		224 346	224 346	224 346
		SC_{MG}		TJ		960	960	960
			GC_{ST1}	t/h		50	50	50
			GC_{ST2}	t/h		50	50	50
			GC_{ST3}	t/h		50	50	50
			GC_{ST4}	t/h		25	25	25
			GC_{ST5}	t/h		25	25	25
			MDH_{ST1}	h		150	150	150
			MDH_{ST2}	h		150	150	150
			MDH_{ST3}	h		150	150	150
			MDH_{ST4}	h		150	150	150
			MDH_{ST5}	h		150	150	150
			EN_{BL1-5}	TJ/t		0.00279	0.00279	0.00279
	SEF_{BL}			t CO2/TJ		53.432	53.432	53.432
		CEF		t C/TJ		15.3	15.3	15.3
		HG_{ST}		TJ		960	960	960
			EN_{BL}	tJ/t		0.0028	0.0028	0.0028
			H_{ST}	t		344 265	344 265	344 265
		$FC_{ST,}$		TJ		914	914	914
			$NCV_{ST,}$	TJ/ths.nm3		0.03	0.03	0.03
			$F_{ST,}$	ths. nm3		27 193	27 193	27 193

Leakages (formulae B.6-13-B.6-14)

LEy							
	$LE_{CH4,y}$		ths. t CO_2		16.806	22.408	22.408
		$FC_{PJ,PF1}$	ths. nm3		45 090	60 120	60 120
		CWP_{CH4}	tCO2/tCH4		21	21	21
		NCV	TJ/ths.nm3		0.03	0.03	0.03
		$EF_{CH4,ups,k,}$	tCH4/TJ		0.528	0.528	0.528

LE y							
	$LE_{CH4,y}$		ths. t CO_2		- 35,917	- 15,376	- 15,376
		$FC_{PJ,PF1}$	ths. nm3		44 178	44 178	44 178
		$FC_{PJ,PF2}$	ths. nm3		27 193	27 193	27 193

$FC_{PJ,PF3}$	ths. nm3		45 090	60 120	60 120
CWP_{CH4}	tCO2/tCH4		21	21	21
NCV	TJ/ths.nm3		0,03	0,03	0,03
$EF_{CH4,ups,k,}$	tCH4/TJ		0,528	0,528	0,528

Currently SE Tirotex has the agreement with Moldovian TPP on electricity supply as in exchange of natural gas with rate of 2,9kWh/1nm^3 (Agreement #1/07E of 29.12.2006). As the project activity will lead to decrease of NG consumption in the frame of the project boundaries (see fig. B.3-1) due to conservative approach the leakages, related to NG consumption, are excluded from the calculations.

Project emissions and ER (formulae B.6-15-B.6-16)

	unit		2010	2011	2012
$FC_{NG,}$	ths. nm3		45 090	60 120	60 120
$NCV_{NG,}$	TJ/ths.nm3		0.03359	0.03359	0.03359
CEF,	t C/TJ		15.3	15.3	15.3
PE,	ths.t CO_{2e}		84.968	113.290	113.290
ER	ths.t CO_{2e}		64.078	63.570	63.570

The results of calculations are given in the table B.6-4. The background data for the calculation are given in the Annex 3.4. During calculations it was assumed that the 1st stage of CHPP will be put into operation since 01.01.2010 and the 2nd stage of CHPP – from 01.01.2011.

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

Table B.6-4 Summary of the ex-ante estimation of emission reductions

Year	Estimation of project activity emissions (tonnes of CO2 e)	Estimation of baseline emissions (tonnes of CO2 e)	Estimation of leakage (tonnes of CO2 e)	Estimation of overall emission reductions (tonnes of CO2 e)
2010	84,968	149,046	16,806	47,272
2011	113,290	176,860	22,408	41,162
2012	113,290	176,860	22,408	41,162
2013	113,290	176,860	22,408	41,162
2014	113,290	176,860	22,408	41,162
2015	113,290	176,860	22,408	41,162
2016	113,290	176,860	22,408	41,162
2017	113,290	176,860	22,408	41,162
2018	113,290	176,860	22,408	41,162
2019	113,290	176,860	22,408	41,162
2020	113,290	176,860	22,408	41,162
Total (tonnes of CO2 e)	1217,868	1917,646	240,886	458,892

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

B.7.1 Data and parameters monitored:

Data / Parameter:	*$CEF_{j,k}$*
Data unit:	tC/TJ
Description:	Carbon emission factor of fuel ‘k’ used by project facility ‘j’ to self-generate electricity in the baseline scenario.
Source of data to be used:	Obtained from the project facility.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	IPCC default value (15,3) - http://www.ipcc-nggip.iges.or.jp/EFDB/ef_detail.php
Description of measurement methods and procedures to be applied:	-
QA/QC procedures to be applied:	-
Any comment:	-

Data / Parameter:	$EF_{PC,GR,i,y}$
Data unit:	tCO_2/MWh
Description:	CO2 emission factor of the grid connected to the project customer in year ‘y’.
Source of data to be used:	National data obtained from Moldovian DFP (National Commission of UNFCCC and Kyoto Protocol Implementation in the Republic of Moldova)
Value of data applied for the purpose of	0.4224

calculating expected emission reductions in section B.5	
Description of measurement methods and procedures to be applied:	In case annual fuel consumption at power plant/unit *j* is not available it will be estimated on the basis of the data on annual net electricity generation, net calorific value of NG and default energy efficiency of power plant according to the latest version of “Tool to calculate the emission factor for an electricity system”.
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned
Any comment:	NG is used mostly as primary fuel at all power plants in Moldova, and as a primary fuel at the new CHPP.

Data / Parameter:	$EF_{CH4,ups}$
Data unit:	tCH4/TJ
Description:	Emission factor for upstream fugitive methane emissions from production, transportation and distribution of NG.
Source of data to be used:	Obtained from the table in the leakage section.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.528
Description of measurement methods and procedures to be applied:	When IPCC data is available, project proponents shall take into consideration that the Board agreed that the IPCC default values should be used only when country or project specific data are not available or difficult to obtain.
QA/QC procedures to be applied:	-
Any comment:	-

Data / Parameter:	$EF_{PF,GR,}$
Data unit:	tCO_2/MWh
Description:	CO_2 emission factor for the grid connected to the project facility in year ‘y’.
Source of data to be used:	National data obtained from Moldovian DFP (National Commission of UNFCCC and Kyoto Protocol Implementation in the Republic of Moldova)
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.4224
Description of measurement methods and procedures to be applied:	
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned
Any comment:	

Data / Parameter:	$EL_{PCSG,,y}$
Data unit:	MWh
Description:	Total electricity self-generated by project customer during year ‘y’ of the crediting period (MWh). Measured at the project customer. Electricity meter at the project

	customer
Source of data to be used:	Electricity meter at the project facility
Value of data applied for the purpose of calculating expected emission reductions in section B.5	128 116
Description of measurement methods and procedures to be applied:	Read electricity meter and store information until 2 years after the end of the crediting period. Monitoring frequency: monthly
QA/QC procedures to be applied:	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data. Crosscheck with purchase receipts and electricity supply data at project site.
Any comment:	-

Data / Parameter:	$SC_{PCSG,,y}$
Data unit:	TJ
Description:	Total steam self-generated by project customer during year 'y' of the crediting period (TJ). Measured at the project customer.
Source of data to be used:	Steam meter at the project customer
Value of data applied for the purpose of calculating expected emission reductions in section B.5	from the 1st stage - 808 from the 2nd stage - 1615
Description of measurement methods and procedures to be applied:	Read steam meter and store information until 2 years after the end of the crediting period. Monitoring frequency: monthly
QA/QC procedures to be applied:	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data. Crosscheck with purchase receipts and electricity supply data at project site.
Any comment:	-

Data / Parameter:	$EL_{PF,GR,y}$
Data unit:	MWh
Description:	Electricity supplied to the grid by the proposed project facility in year 'y' (MWh/yr). Measured at the project facility
Source of data to be used:	Electricity meter at the project facility
Value of data applied for the purpose of calculating expected emission reductions in section B.5	from the 1st stage – 53 874 from the 2nd stage - 60 664
Description of measurement methods and procedures to be applied:	Read electricity meter and store information until 2 years after the end of the crediting period. Monitoring frequency: monthly

QA/QC procedures to be applied:	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data. Crosscheck with purchase receipts and electricity supply data at project site.
Any comment:	-

Data / Parameter:	$EL_{PJ,j,i,y}$
Data unit:	MWh
Description:	Electricity purchased by the project customer from the proposed project facility in year 'y'.
Source of data to be used:	Electricity meter at the project facility or the project customer.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	128 116
Description of measurement methods and procedures to be applied:	Read electricity meter and store information until 2 years after the end of the crediting period. Monitoring frequency: monthly
QA/QC procedures to be applied:	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data. Crosscheck with purchase receipts and electricity supply data at project site.
Any comment:	-

Data / Parameter:	$EN_{PJ,}$
Data unit:	kJ/kg
Description:	Specific enthalpy of the steam purchased by project customer. This data shall be obtained from steam tables, using temperature and pressure of the steam purchased measured at the project customer.
Source of data to be used:	Steam tables
Value of data applied for the purpose of calculating expected emission reductions in section B.5	2773
Description of measurement methods and procedures to be applied:	Use monitored pressure and temperature of the steam to obtain specific enthalpy from steam tables: www.dpva.ru/informations/Mtls/Gases/Steam/SaturatedSteam0to100bar/ Monitoring frequency: monthly
QA/QC procedures to be applied:	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data.
Any comment:	-

Data / Parameter:	*Steam temperature*
Data unit:	^{O}C
Description:	Temperature of steam purchased by project customer 'i'.
Source of data to be used:	Temperature meters at project customer 'i'
Value of data applied	175.4

for the purpose of calculating expected emission reductions in section B.5	
Description of measurement methods and procedures to be applied:	Store information until 2 years after the end of the crediting period. Monitoring frequency: read temperature meter daily and calculate monthly average. Daily measurements and monthly average.
QA/QC procedures to be applied:	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data.
Any comment:	-

Data / Parameter:	*Steam pressure*
Data unit:	bar
Description:	Pressure of steam purchased by project customer.
Source of data to be used:	Pressure meters at project customer
Value of data applied for the purpose of calculating expected emission reductions in section B.5	8
Description of measurement methods and procedures to be applied:	Store information until 2 years after the end of the crediting period. Monitoring frequency: read pressure meter daily and calculate monthly average. Daily measurements and monthly average.
QA/QC procedures to be applied:	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data.
Any comment:	-

Data / Parameter:	$FC_{PJ,PF,y}$
Data unit:	nm^3
Description:	Quantity of consumed NG in the year ‘y’ in the project facilities.
Source of data to be used:	Measured at the project facility from purchase records and fuel data logs.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	at the 1^{st} stage – 45 090 139 at the 2^{nd} stage - 15 030 046
Description of measurement methods and procedures to be applied:	Measured at the project facility from fuel data logs. Store information until 2 years after the end of the crediting period.
QA/QC procedures to be applied:	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data.
Any comment:	-

Data / Parameter:	GWP_{CH4}
Data unit:	tCO_2/tCH_4
Description:	Global warming potential of CH4 valid for the commitment period.
Source of data to be	Obtained from IPCC

used:	
Value of data applied for the purpose of calculating expected emission reductions in section B.5	21
Description of measurement methods and procedures to be applied:	-
QA/QC procedures to be applied:	-
Any comment:	-

Data / Parameter:	$J_{EL,i,y}$
Data unit:	Number
Description:	Number of project facilities supplying the project customer with electricity in year ‘y’ simultaneously.
Source of data to be used:	Obtained from the project customer.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	1 (CHPP with 8 gensets)
Description of measurement methods and procedures to be applied:	Store information until 2 years after the end of the crediting period.
QA/QC procedures to be applied:	-
Any comment:	-

Data / Parameter:	$J_{ST,i,y}$
Data unit:	Number
Description:	Number of project facilities supplying steam to the project customer in year ‘y’, simultaneously.
Source of data to be used:	Obtained from the project customer.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	1 (CHPP with 4 steam boilers)
Description of measurement methods and procedures to be applied:	Obtained from the project customer. Store information until 2 years after the end of the crediting period.
QA/QC procedures to be applied:	-
Any comment:	-

Data / Parameter:	NCV
Data unit:	MJ/nm3

Description:	Net calorific value of NG at project facility
Source of data to be used:	Obtained from the project customer.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	33.59
Description of measurement methods and procedures to be applied:	When IPCC data is available, project proponents shall take into consideration that the Board agreed that the IPCC default values should be used only when country or project specific data are not available or difficult to obtain.
QA/QC procedures to be applied:	Provided by the gas supplier
Any comment:	-

Data / Parameter:	$STT_{PU,,y}$
Data unit:	Tonne
Description:	Steam purchased by the project customer from the proposed project facility in year 'y'.
Source of data to be used:	Measured at the project facility and/or at the project customer.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	from the 1st stage – 133 134 from the 2nd stage - 44 378
Description of measurement methods and procedures to be applied:	Monitoring frequency: Monthly read steam meter and store information until 2 years after the end of the crediting period
QA/QC procedures to be applied:	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data. Crosscheck with purchase receipts and steam supply data at project site.
Any comment:	-

B.7.2. Description of the monitoring plan:

The emission reduction achieved by the project activity will be calculated according to the monitoring methodology version 03 of AM0048 "**New cogeneration facilities supplying electricity and/or steam to multiple customers and displacing grid/off-grid steam and electricity generation with more carbon-intensive fuels**". Monitoring shall involve:

1. Data required for calculation of project emissions (annual natural gas consumption at the new CHPP, net calorific value of natural gas consumed at the new CHPP);

2. Data required for calculation of baseline emissions:

2.1. Annual net electricity, steam and heat generation at the new CHPP;

2.2. Annual performance data for power plants/units (see Annex 3-2) serving the grid (net electricity generated and delivered to the grid, fuel consumption, net calorific value of consumed fuel and the CO2 emission factor of the consumed fuel).

Data should be obtained from the meters with accuracy of 95% or greater. The baseline CO2 emission factor and emission factor for upstream fugitive methane emissions occurring in the absence of the project activity will be updated annually. All calculations are performed as per method described in Section B.6

The project does not envisage any changes in the structure of collection and analysis of data on fuel consumption and net electricity generation at the new CHPP and at the power plants/units *j* serving the grid. Data will be collected in any case.

SE "Tirotex" is responsible for collection and accuracy of data required for monitoring. GHG emission reductions will be calculated annually on the basis of the data received from SE "Tirotex". In case of any doubts about accuracy of the initial data, specialists of SE "Tirotex" will check and revise the data. If any mistakes in calculations of GHG emission reductions are found by a verificator, the calculations shall be corrected accordingly.

Detailed description of the monitoring plan is presented in Annex 4.

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

Date of completion of the application of the methodology to the project activity study: 01/01/2009
Name of person/entity determining the baseline and monitoring methodology:
SEC Biomass
Contact person: Kalinichenko Tatiana
E-mail: kalinichenko@biomass.kiev.ua

SECTION C. Duration of the project activity / crediting period

C.1. Duration of the project activity:

C.1.1. Starting date of the project activity:

02 June 2008 (the construction of the new CHPP) (**Decision on CHPP construction permit** was provided to AIE)

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

20 years/240 months

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

The project activity will use a renewable crediting period which is accordingly noted in C.2.1.

C.2.1. Renewable crediting period:

Each crediting period shall be at most 7 years and may be renewed at most two times. For each renewal, a designated operational entity determines and informs the Executive Board that the original project baseline is still valid or has been updated taking account of new data where applicable.

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

01/12/2012 (1st January 2011 is the expected date of project approval by CDM EB)

C.2.1.2. Length of the first crediting period:

7 years/84 months: 1st January 2012 – 31st December 2018.

C.2.2. Fixed crediting period:

n/a

C.2.2.1. Starting date:

n/a

C.2.2.2. Length:

n/a

SECTION D. Environmental impacts

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

The bulk of electricity in the Republic of Moldova is generated by CHPs that were built more than 30 years ago. Despite of use natural gas as primary fuel they have low efficiency as 10-20%. Residual fuel oil is used as an auxiliary fuel and as well as also coal can be used as a primary fuel at Moldovian TPP. The primary and standby fuel at the new CHPP is natural gas, which is a clearer kind of fossil fuel regarding sulphur dioxide (SO2) and CO2 emissions as compared with residual fuel oil and coal. The project implementation will result in reduction of net electricity generation at the grid power plants. Emissions of solid particles and SO2 into the atmosphere will be reduced through decrease of fossil fuel consumption at the TPPs.

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

According the law in The Republic of Moldova an Environmental Impact Assessment has to be performed for this project (Executive summary is given at the Annex 5).

The short description of EIA can be found in the Annex 5. The required seal of approval for the environmental impact assessment had been obtained before the construction works began The environmental impacts of the project activity are not considered to be significant. Implementation of the project will result in reduced emissions of SO2 and CO2 into the atmosphere.

SECTION E. Stakeholders' comments

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

On November 14-15, 2005 the International conference dedicated to the issue of planning of construction of CHP plant at SE "Tirotex" was conducted at the Tirotex site. Participants represented management staff of SE "Tirotex", local governmental representative, engineering companies, and engineering companies from Russia, Ukraine, Germany, Finland.

Information on the construction of the new CHPP appeared in local mass media sources, e.g. on November 24, 2005, in the newspaper "Pridnestrovje".

In item 11 of Annex 2 of Environment Impact Assessment report is mentioned that the public was informed about planned activity and its expected results by article in local newspaper. During EIA process comments from the public were invited.

The project complies with current norms and requirements in the Republic of Moldova. Therefore all related local authorities are involved (EIA is approved by the Ministry of Ecology, an innovative project certificate will be given by the Ministry of Industrial Policy, the licence on generation of the electricity will be issued by the Ministry of Energy etc.)

E.2. Summary of the comments received:

No comments were received.

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

n/a

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Project Participant 1

Organisation:	SE “Tirotex”
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E-mail:	tiro@tirotex.com
URL:	www.tirotex.com
Represented by:	
Title:	General Director
Salutation:	Mr.
Last name:	Ordin
Middle name:	Nikolaevich
First name:	Vilor
Department:	
Phone (direct):	
Fax (direct):	
Mobile:	
Personal e-mail:	

Project Participant 2

Organisation:	SEC “Biomass”
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E-mail:	info@biomass.kiev.ua
URL:	www.biomass.kiev.ua
Represented by:	
Title:	Director
Salutation:	Mr.
Last name:	Geletukha
Middle name:	Georgievich
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Project Participant 3

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Represented by:	
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Middle name:	
First name:	Francisco
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Mobile:	
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Direct tel:	+31 (0) 20-880985455
Personal e-mail:	

Annex 2

INFORMATION REGARDING PUBLIC FUNDING

There are no public funds involved in the project activity.

Annex 3

BASELINE INFORMATION

Annex 3-1. Basic scheme of power grid in the Republic of Moldova

Annex 3-2. List of power plants/units serving the grid

Name of power plant/unit	Installed electrical capacity, MW	Type of fuel	Electric Efficiency[5]	Year of commissioning in
except low-cost/must-run power plants/unit				
Moldovan TPP	**2520**	**Gas, coal, residual fuel oil**	**0.33**	**1964-1980**
CHP-1	46	Gas, residual fuel oil	0.13	1951-1974
CHP-2	**240**	**Gas, residual fuel oil**	**0.2**	**1976-1980**
CHP-North	28	Gas, residual fuel oil	0.1	1956-1970
SF “Alexandreni” SE	12	Residual fuel oil	0.2	1963-1964
“North Zahar” SE, Briceni	18	Residual fuel oil	0.2	1985
SF “Cupcini-Cristal” SE	12	Gas, residual fuel oil	0.2	1961-1981
SF “Donbuseni” SE	10	Gas, residual fuel oil	0.2	1957-1991
SF “Drochia-Zahar” SE	10	Gas, residual fuel oil	0.2	1956-1980
SF “F.Z. Falesti” SE	**7.5**	**Gas, residual fuel oil**	**0.2**	**1969-1981**
SF ”Frunze” SE, Garbova	**12**	**Gas, residual fuel oil**	**0.2**	**1969-1981**
SF “Trecontact-Zahar” SE, Ghindesti	6	Residual fuel oil	0.2	1982
SF “Glodeni-Zahar” SE	10	Gas, residual fuel oil	0.2	1977
low-cost/must-run power plants/unit				
HPP Dubasari	48	-	-	1954
HPP Costesi	**16**	**-**	**-**	**1978**

The five most recently built PPs are marked in green.

[5] Given data for 2000 yr. For SF CHPs the electrical efficiency is assumed as 20% according to the conservative approach and for others PP is taken from Technology needs and development. Chishinau 2002.

Annex 3-3 Proposed project activity

The main data (marked blue) were provided by the SE Tirotex. Other figures were calculated

2. Technical inputs

PROPOSED SYSTEM:

waste heat from 1 genset	4.753	MWth (out)		
Thermal capacity 1st stage	10.5	MWth (out)	9	Gcal/h
Thermal capacity 2nd stage	3.5	MWth (out)	3	Gcal/h
Capacity of 1 genset	3.916	MWel		
number of units at 1st stage	6			
number of units at 2nd stage	2			
Power capacity, 1st stage	23.496	MWel		
Power capacity, 2nd stage	7.832	MWel		
Nominal operating hours/ Загрузка установки	8 600	h/a		
Nominal loading rate	100%			
Electrical efficiency	41.9%			
Waste heat utilization efficiency	44.7%			
Total efficiency	87%			
Thermal of fuel to be input 1st stage	1 214 130	GJ/a	289 768	Gcal/a
Thermal of fuel to be input 2nd stage	404 710	GJ/a	96 589	Gcal/a
Natural gas input	nm3/a		LHV (MJ/nm3)	
NG comnsumption 1st stage	45 090 139		33.59	DEC,2007
NG comnsumption 2nd stage	15 030 046			

New Process Outputs				
Heat produced 1st stage	324 000	GJ/a	77 327	Gcal/a
Heat produced 2nd stage	108 000	GJ/a	25 776	
Heat losses (own needs)	2.2	%		
Heat provided to consumers 1st stage	316 872	GJ/a	75 626	Gcal/a
Heat provided to consumers 2nd stage	105 624	GJ/a	25 209	Gcal/a
electricity produced 1st stage	202 066	MWh/a		
electricity produced 2nd stage	67 355	MWh/a		
electricity consumed for own needs	2.2	%		
electricity delivered to consumers 1st stage	197 539	MWh/a		
electricity delivered to consumers 2nd stage	65 846	MWh/a		

electricity for own needs

Specific consumption of electricity for heat production	22	kWh/Gcal
Specific consumption of electricity for electricity production	0.014	kWh/kWh

1 stage			% electricity own needs	
heat produced	77 400	Gcal/a	24MW	2.24%
electricity own needs consumed	1 703	MWh/a		
electricity produced	202 066	MWh/a		
electricity own needs consumed	2 829	MWh/a		
2nd stage			7MW	2.24%

heat produced	25 800	Gcal/a		
electricity own needs consumed	568	MWh/a		
electricity produced	67 355	MWh/a		
electricity own needs consumed	943	MWh/a	31MW	2.24%

steam characteristics	
boiling point, ^{0}C	175.4
pressure, bar	8
density, kg/m3	4.65
Specific entalpy of saturated steam, kJ/kg	2772.13
Specific entalphy of the feeding water, kJ/kg	440.00
steam produced 1st stage, t	135 872
steam produced 2nd stage, t	45 291

4 a. Investment costs 1st stage		
Item	**Euro**	**US$**
Business plan development	7 114	8 892
Design works	386 540	483 175
6 DEUTZ gensets including all taxes	9 560 998	11 951 247
2 heat recovery boilers icluding all taxes	279 357	349 196
additional equipment	3 415 746	4 269 683
gas meaters	86 400	108 000
transformers and reactors	368 324	460 405
coolers	388 080	485 100
pumps, valves	482 400	603 000
chimneys	324 903	406 129
ventilation	92 736	115 920
switchgears	475 183	593 979
transformers of SS	124 044	155 055
reactive compensators	107 568	134 460
electricity meaters	41 496	51 870
bypass valve	94 229	117 786
vacuum cells	90 400	113 000
chemical water treatment and preparation equipment	429 991	537 489
lime slaking equipment	37 090	46 363
protective relays	80 707	100 884
water piplenes	93 366	116 708
heat exchangers	87 900	109 875
flue gas ducts	10 928	13 660
construction works	1 244 746	1 555 933
precommissioning	67 526	84 408
Other costs	1 520 000	1 900 000
Total	16 482 027	**20 602 534**

4 b. Investment costs 2nd stage		
Item	**Euro**	**US$**
Business plan development	1 760	2 200
Design works	112 000	140 000
2 DEUTZ gensets including all taxes	3 187 200	3 984 000
1 heat recovery boiler including all taxes	311 040	388 800
additional equipment	365 722	457 153

baffle valve, dampfers	284 122	355 153
generator	57 600	72 000
cable products	24 000	30 000
construction works	435 661	544 577
precommissioning	33 763	42 204
Other costs	782 396	977 995
vizualization system	30 000	37 500
cable products	25 200	31 500
thermal isulation of external net	160 800	201 000
thermal isulation of internal net	144 000	180 000
unforeseen 10%	422 396	527 995
Total	5 229 543	**6 536 929**

5. Economical inputs

Discount rate			10%	
Bank interest rate			11%	
Term of loan			3	years
own money	4 415 445	Euro	5 519 306	US$
Loan investments	14 441 063	Euro	18 051 329	US$
1st credit	2 930 539	Euro	3 663 174	US$
2nd credit	6 280 981	Euro	7 851 226	US$
3rd credit	5 229 543	Euro	6 536 929	
Share of prepayment for CERs	0%	Euro	0%	US$

As for financial sources of the 2nd stage construction it was assumed that the money will be taken from a bank under the same conditions that the first loan.

INVESTMENT COSTS, euro

		2008	2009	2010	2011	2012	2013	2014	2028
Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**Scrap value**
construction	1 698 813	583 184							
Equipment	13 256 101	3 863 962							
Other	1 527 114	782 396							
TOTAL INVESTMENT COSTS, euro	16 482 027	5 229 543	0	0	0	0	0	0	116 745
		21 711 570							

Payments for credit, euro

Year	0	1	2	3	4	5	6	7	Total
Return of 1st credit	293 054	1 758 324	879 162	0	0	0	0	0	2 930 539
Leaving unpaid 1st credit credit	2 637 485	879 162	0	0	0	0	0	0	
Loan interest for 1st credit	52 383	201 475	28 206	0	0	0	0	0	282 064
Return of 2nd credit	2 093 660	2 791 547	1 395 774	0	0	0	0	0	6 280 981
Leaving unpaid 2nd credit credit	4 187 321	1 395 774	0	0	0	0	0	0	
Loan interest for 2nd credit	83 165	319 865	44 781	0	0	0	0	0	447 811
total repayment of both credits	2 386 714	4 549 871	2 274 935	0	0	0	0	0	9 211 520
total loan interest for both credits	135 548	521 339	72 988	0	0	0	0	0	729 875
Return of 3rd credit		522 954	3 137 726	1 568 863	0	0	0	0	5 229 543
Leaving unpaid 3rd credit credit		4 706 589	1 568 863	0	0	0	0	0	
Loan interest for 3rd credit		93 478	359 531	50 334	0	0	0	0	503 344
TOTAL PAYMENTS FOR CREDIT, euro	2 522 262	5 687 642	5 845 180	1 619 197	0	0	0	0	15 674 282

Operational costs 1st stage

ANNUAL OPERATIONAL COSTS, Euro		Unit costs	Units	Unit costs	Units	Units/a	Units	Costs, €/a
Naural gas purchasing		126.80	US$/1000 nm3	101.44	€/1000 nm3	45 090	1000 nm3/a	4 573 944
Personnel expences (wages, taxes)	Number of workers							41
	Number of engineers							7
Average wage of a worker		332	US$/month	266	€/month	12	months/a	3 187
Average wage of an engineer		414	US$/month	331	€/month	12	months/a	3 974

Total wage expences							months/a	158 496
Wage taxes (social, unemployment, retirement, etc)	26.0%	194	US$/month	155	€/month	12	months/a	41 209
overhead costs	55.0%							87 173
Maintainance		0.00350	US$/kWh	0.0028	€/kWh	202 065 600	kWh/a	565 784
Electricity		48.07	US$/MWh	38.456	€/MWh		Euro/a	174 272
Water for boiler-operation		0.08	US$/m3	0.065	€/m3	24 000	m3/a	1 563
Sewerage		0.10	US$/m3	0.078	€/m3	21 600	m3/a	1 676
fuels and lubricants		3.96	US$/kg	3.168	€/kg	0.3	kg/MWh/a	192 043
TOTAL OPERATIONAL COSTS, Euro/a								**5 796 159**

Operational costs 2nd stage

ANNUAL OPERATIONAL COSTS, Euro		Unit costs	Units	Unit costs	Units	Units/a	Units	Costs/a
Naural gas purchasing		126.80	US$/1000 nm3	101.44	€/1000 nm3	15 030	1000 nm3/a	1 524 648
Personnel expences (wages, taxes)	Number of workers							13
	Number of engineers							2
Average wage of a worker		332	US$/month	266	€/month	12	months/a	3 187
Average wage of an engineer		414	US$/month	331	€/month	12	months/a	3 974
Total wage expences						12	months/a	49 382
Wage taxes (social, unemployment, retirement, etc)	26.0%	194	US$/month	155	€/month	12	months/a	12 839
overhead costs	55.0%							27 160
Maintainance		0.00350	US$/kWh	0.0028	€/kWh	67 355 200	kWh/a	188 595
Electricity		48.07	US$/MWh	38.4560	€/MWh		Euro/a	58 091
Water for boiler-operation		0.08	US$/m3	0.0651	€/m3	12 000	m3/a	781
Sewerage		0.10	US$/m3	0.0776	€/m3	10 800	m3/a	838
fuels and lubricants		3.96	US$/kg	3.1680	€/kg	0.3	kg/MWh/a	64 014
TOTAL OPERATIONAL COSTS, Euro/a								**1 930 338**

Revenues 1st stage

ANNUAL REVENUES, Euro		Unit price	Units	Unit price	Units	Units/a	Units	Costs/a

Avoiding of heat purchasing (heat sales)		27.03	US$/Gcal	21.6234	euro/Gcal	75 626	Gcal/a	1 635 283
Avoiding of natural gas purchasing		0.00	US$/1000m3	0.00	euro/1000m3	0	1000m3/a	0
Avoiding of power purchasing		22.69	US$/MWh	18.1549	euro/MWh	128 116	MWh/a	2 325 936
Income from power supply to the grid		43.26	US$/MWh	34.6104	euro/MWh	69 423	MWh/a	2 402 758
CERs pre-payments		0.00	US$/t CO2 eq	0.00	euro/t CO2 eq	0	t/a	0
Total								**6 363 977**
Payments for CERs		15.63	US$/t CO2 eq	12.5000	euro/t CO2 eq	0	t/a	**0**

Revenues 2nd stage

ANNUAL REVENUES, Euro		**Unit price**	**Units**	**Unit price**	**Units**	**Units/a**	**Units**	**Costs/a**
Avoiding of heat purchasing (heat sales)		27.03	US$/Gcal	21.6234	euro/Gcal	25 209	Gcal/a	545 094
Avoiding of natural gas purchasing		0.00	US$/1000m3	0.00	euro/1000m3	0	1000m3/a	0
Income from power supply to the grid		43.26	US$/MWh	34.6104	euro/MWh	65 846	MWh/a	2 278 972
CERs pre-payments		0.00	US$/t CO2 eq	0.00	euro/t CO2 eq		t/a	0
Total								**2 824 066**
Payments for CERs		15.63	US$/t CO2 eq	12.5000	euro/t CO2 eq	0	t/a	**0**

Prices, tariffs, currency exchange

	Euro	USD	PMR			
Currency Exchange	0.088	0.11	1			
	PMR		US$		euro	
Heat supply tariff	245.7	PMR/Gcal	27.03	US$/Gcal	21.62	euro/Gcal
Natural gas price	1152.7	PMR/1000m3	126.80	US$/1000m3	101.44	euro/1000m3
CER price	142.0	PMR/t CO2 eq	15.63	US$/t CO2 eq	12.50	euro/t CO2 eq
Industrial water	0.7	PMR/m3	0.08	US$/t	0.07	euro/t
fuels and lubricants	36.0	PMR/kg	3.96	US$/kg	3.17	euro/kg
Sewerage	0.9	PMR/m3	0.10	US$/t	0.08	euro/t

Power tariff for buying of electricity	437.0	PMR/MWh	48.07	US$/MWh	38.46	euro/MWh
Power tariff for selling of electricity	393.3	PMR/MWh	43.26	US$/MWh	34.61	euro/MWh

The currency exchange rate was taken from http://www.cbpmr.net/?kv=1&lang=en for 1Dec. 2007 when the investment decision was made.

Annex 3-4 Alternative 1

The data were partially provided by SE Tirotex, others were taken from technical studies

Technical input

PROPOSED SYSTEM:

Steam Viessmann boilers Vitomaxx 200 (10 bar) M235 with economizer ECO200				
productivity	25.000	t/h		
number of units	2			
Steam parameters				
boiling point, ^{0}C	175.4			
pressure, bar	10			
Specific entalpy of saturated steam, kJ/kg	2779.66			
Specific entalphy of the feeding water, kJ/kg	440.00			
Capacity	116.98	MJ/h		
	32.50	MWth		
Nominal operating hours/ Загрузка установки	6 000	h/a		
Nominal loading rate	90%			
Efficiency	96.0%			
Thermal of fuel to be input	658 029	GJ/a	157 048	Gcal/a
Natural gas input	nm3/a		LHV (MJ/nm3)	
NG comnsumption	19 590 038		33.59	DEC,2007

New Process Outputs				
Heat produced	568 537	GJ/a	135 689	Gcal/a
Heat losses (own needs)	2.0	%		
Heat provided to consumers	557 167	GJ/a	132 975	Gcal/a
electricity consumed for own needs	2.0	%		
electricity consumed by additional equipment	3 899	MWh/a		

4 c. Investment costs for a new boiler house			
Item	**Euro**	**US$**	
Business plan development	6 400	8 000	asssumed as for CHP
Design works	80 000	100 000	asssumed as 70% of costs of 2nd stage of CHP
2 Steam Viessmann boilers Vitomaxx 200 (10 bars) M235 with economizer ECO200 including all taxes	2 119 154	2 648 942	provided by the project consumer
additional equipment for boilers	703 997	879 996	
chemical water treatment and preparation equipment	429 991	537 489	

construction works	650 628	813 285	assumed as 20% as equipment costs
precommissioning	325 314	406 643	assumed as 10% as equipment costs
Other costs	0		
unforeseen 20%	863 097	1 078 871	
Total	5 178 581	**6 473 226**	

5. Economical inputs

Discount rate			10%	
Bank interest rate			11%	
Term of loan			3	years
own money	4 415 445	Euro	5 519 306	US$
Loan investments	763 136	Euro	953 920	US$

INVESTMENT COSTS, euro

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**Scrap value**
construction	650 628											
Equipment	3 253 142											
Other	1 274 811											
TOTAL INVESTMENT COSTS, euro	5 178 581	0	0	0	0	0	0	0	0	0	0	36 681

Payments for credit, euro

Year	0	1	2	3	4	5	6	7	8	9	10	Total
Return of credit	441 544	2 649 267	1 324 633	0	0	0	0	0	0	0	0	4 415 445
Leaving unpaid credit credit	3 973 900	1 324 633	0	0	0	0	0	0	0	0	0	
Loan interest for credit	78 926	303 562	42 499	0	0	0	0	0	0	0	0	424 987
TOTAL PAYMENTS FOR CREDIT, euro	520 471	2 952 829	1 367 132	0	0	0	0	0	0	0	0	4 840 431

Operational costs

ANNUAL OPERATIONAL COSTS, Euro		Unit costs	Units	Unit costs	Units	Units/a	Units	Costs, €/a
Naural gas purchasing		126.80	US$/1000 nm3	101.44	€/1000 nm3	19 590	1000 nm3/a	1 987 213
Personnel expences (wages, taxes)	Number of workers							15
	Number of engineers							7
Average wage of a worker		332	US$/month	266	€/month	12	months/a	3 187
Average wage of an engineer		414	US$/month	331	€/month	12	months/a	3 974
Total wage expences							months/a	75 629
Wage taxes (social, unemployment, retirement, etc)	26.0%	194	US$/month	155	€/month	12	months/a	19 663
overhead costs	55.0%							41 596
Maintainance				3 000	€/month	12	months/a	36 000
Electricity costs for boiler operation		0.048	US$/kWh	0.038	€/kWh	3 899	MWh/a	149 957

Water for steam production		0.16	US$/m3	0.13	€/m3	75 750	m3/a	9 514
TOTAL OPERATIONAL COSTS, Euro/a								**2 319 572**

Revenues

ANNUAL REVENUES, Euro	**Unit price**	**Units**	**Unit price**	**Units**	**Units/a**	**Units**	**Costs/a**
heat sales	2.13	US$/Gcal	19.39	euro/Gcal	132 975	Gcal/a	2 578 501
Total							**2 578 501**

5.Calculations

Income tax rate	**2.0%**
Amortization rate	**6.00%**

	Year of operation													*Scrap value*
	2008	***2009***	***2010***	***2011***	***2012***	***2013***	***2014***	***2015***	***2024***	***2025***	***2026***	***2027***	***2028***	
	0	***1***	***2***	***3***	***4***	***5***	***6***	***7***	***16***	***17***	***18***	***19***	***20***	
Investment costs	5 178 581													
Operational costs		2 319 572	2 319 572	2 319 572	2 319 572	2 319 572	2 319 572	2 319 572	2 319 572	2 319 572	2 319 572	2 319 572	2 319 572	
Loan re-payment	520 471	2 952 829	1 367 132	0	0	0	0	0	0	0	0	0	0	
Amortization assesments		1 135 409	886 470	692 110	540 364	421 889	329 389	257 170	27 722	21 644	16 898	13 193	10 301	36 681
Total revenue	0	2 578 501	2 578 501	2 578 501	2 578 501	2 578 501	2 578 501	2 578 501	2 578 501	2 578 501	2 578 501	2 578 501	2 578 501	
Balance sheet profit	0	-3 829 309	-1 994 673	-433 181	-281 435	-162 960	-70 460	1 759	231 207	237 285	242 031	245 736	248 628	
Income tax	0	0	0	0	0	0	0	35	4 624	4 746	4 841	4 915	4 973	
Net profit	0	-3 829 309	-1 994 673	-433 181	-281 435	-162 960	-70 460	1 724	226 583	232 539	237 190	240 821	243 656	
Cash flow	-5 178 581	-2 693 900	-1 108 203	258 929	258 929	258 929	258 929	258 894	254 305	254 183	254 088	254 014	253 956	
Money on the account	**-5 178 581**	**-7 872 481**	**-8 980 684**	**-8 721 755**	**-8 462 826**	**-8 203 896**	**-7 944 967**	**-7 686 074**	**-5 385 978**	**-5 131 795**	**-4 877 706**	**-4 623 692**	**-4 369 736**	**-4 333 055**
Simple payback period														
Discount factor	1	0.909	0.826	0.751	0.683	0.621	0.564	0.513	0.218	0.198	0.180	0.164	0.149	0.350

Discounted Cash flow		-2449000	-915870	194537	176852	160775	146159	132853	55344	50289	45700	41533	37749	12856
Discounted money on the account	**-5 178 581**	**-7627581**	**-8543451**	**-8348914**	**-8172062**	**-8011287**	**-7865128**	**-7732275**	**-6976209**	**-6925920**	**-6880220**	**-6838687**	**-6800938**	**-7391448**
Discounted payback period														

Economic indexes

Net Pesent Value	**-6 182 671**	**Euro**
Internal Return Rate		
Simple Payback Period	**>10 years**	**years**
Discounted payback period	**>10**	**years**

Annex 3-5 Alternative 2 Operation of the existing boiler house

The main data (marked blue) were provided by the SE Tirotex. Other figures where calculated

PROPOSED SYSTEM:

3 Steam Boilers GM 50/14, 2 steam boilers DE 25/14				
productivity	25.000	Gcal/h		
	45	t/h		
Capacity	29.07	MWth		
Nominal operating hours/ Загрузка установки	6 000	h/a		
Nominal loading rate	100%			
Efficiency	90%		0.90	
Thermal of fuel to be input	697 674	GJ/a	166 509	Gcal/a
Natural gas input	nm3/a		LHV (MJ/nm3)	
NG comnsumption	20 770 301		33.59	DEC,2007

New Process Outputs				
Heat produced	627 907	GJ/a	149 858	Gcal/a
Heat losses (own needs)	8.0	%		
Heat provided to consumers	577 674	GJ/a	137 870	Gcal/a
electricity consumed for own needs	4.0	%		
electricity consumed by additional equipment	6 977	MWh/a		

Operational costs

ANNUAL OPERATIONAL COSTS, Euro		Unit costs	Units	Unit costs	Units	Units/a	Units	Costs, €/a
Naural gas purchasing		126.80	US$/1000 nm3	101.44	€/1000 nm3	20 770	1000 nm3/a	2 106 939
Personnel expences (wages, taxes)	Number of workers							30
	Number of engineers							7
Average wage of a worker		332	US$/month	266	€/month	12	months/a	3 187
Average wage of an engineer		414	US$/month	331	€/month	12	months/a	3 974
Total wage expences							months/a	123 437
Wage taxes (social, unemployment, retirement, etc)	26.0%	194	US$/month	155	€/month	12	months/a	32 094
overhead costs	55.0%							67 890
Maintainance				3 000	€/month	12	months/a	36 000
Electricity costs for boiler operation, assumed as 2% of heat capacity		0.000	US$/kWh	0.000	€/kWh	6 977	MWh/a	2 701
Water for steam production		0.16	US$/m3	0.126	€/m3	45 170	m3/a	5 673
TOTAL OPERATIONAL COSTS, Euro/a								**2 374 735**

Revenues

ANNUAL REVENUES, Euro		Unit price	Units	Unit price	Units	Units/a	Units	Costs/a
heat sales		21.53	US$/Gcal	17.22	euro/Gcal	137 870	Gcal/a	2 374 735
Total								**2 374 735**

Annex 3-6 Alternative 3.1 Construction of CHPP with CDM impact

Income tax rate	**2.0%**
Amortization rate	**6.00%**

	Year of operation												*Scrap value*
	2008	***2009***	***2010***	***2011***	***2012***	***2013***	***2023***	***2024***	***2025***	***2026***	***2027***	***2028***	
	0	***1***	***2***	***3***	***4***	***5***	***15***	***16***	***17***	***18***	***19***	***20***	
Investment costs	16 482 027	5 229 543											
Operational costs		4 347 119	7 243 913	7 726 498	7 726 498	7 726 498	7 726 498	7 726 498	7 726 498	7 726 498	7 726 498	7 726 498	7 726 498
Loan interests	135 548	614 817	432 519	50 334	0	0	0	0	0	0	0	0	0
Amortization assesments 1st stage		3 613 702	2 821 394	2 202 800	1 719 834	1 342 759	113 009	88 231	68 887	53 783	41 991	32 785	116 745
Amortization assesments 2nd stage		1 146 583	895 193	698 921	545 682	426 041	35 856	27 995	21 857	17 065	13 323	10 402	37 042
Total revenue	0	4 772 983	10 088 324	10 970 442	10 970 442	9 188 044	9 188 044	9 188 044	9 188 044	9 188 044	9 188 044	9 188 044	9 188 044
Balance sheet profit	0	-4 334 421	-872 176	342 223	978 429	-307 253	1 312 681	1 345 320	1 370 803	1 390 698	1 406 232	1 418 359	1 307 759
Income tax	0	0	0	6 844	19 569	0	26 254	26 906	27 416	27 814	28 125	28 367	0
Net profit	0	-4 334 421	-872 176	335 379	958 860	-307 253	1 286 427	1 318 413	1 343 386	1 362 884	1 378 107	1 389 992	1 307 759
Cash flow	-16 482 027	-4 803 679	2 844 412	3 237 100	3 224 376	1 461 546	1 435 292	1 434 640	1 434 130	1 433 732	1 433 421	1 433 179	1 461 546
	-16 482 027	-21 285 707	-18 441 295	-15 204 195	-11 979 818	-10 518 272							
		0	0	0	0	0							
Money on the account	**-16 482 027**	**-21 285 707**	**-18 441 295**	**-15 204 195**	**-11 979 818**	**-10 518 272**	**3 920 250**	**5 354 890**	**6 789 020**	**8 222 752**	**9 656 173**	**11 089 352**	**-1 805 723**
Simple payback period		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	
Simple payback period													
Discount factor	1	0.909	0.826	0.751	0.683	0.621	0.239	0.218	0.198	0.180	0.164	0.149	0.135
Discounted Cash flow		-4366981	2350753	2432082	2202292	907505	343598	312219	283735	257869	234376	213033	197500
Discounted money on the account	**-16 482 027**	**-20849008**	**-18498255**	**-16066174**	**-13863881**	**-12956376**	**-7439699**	**-7127480**	**-6843745**	**-6585876**	**-6351500**	**-6138467**	**-9343479**
		0.00	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	
Discounted payback period													
Economic indexes													

Net Pesent Value	**-5 896 008**	**Euro**
Internal Return Rate	**4.8%**	
Simple Payback Period	**12.8**	**years**
Discounted payback period	**>10**	**years**

Annex 3-7 Alternative 3.2 Construction of CHPP without CDM impact

	Year of operation												*Total*
	2008	*2009*	*2010*	*2011*	*2012*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	
	0	*1*	*2*	*3*	*4*	*14*	*15*	*16*	*17*	*18*	*19*	*20*	
Investment costs	16 482 027	5 229 543											
Operational costs		4 347 119	7 243 913	7 726 498	7 726 498	7 726 498	7 726 498	7 726 498	7 726 498	7 726 498	7 726 498	7 726 498	7 726 498
Loan re-payment	2 522 262	5 687 642	5 845 180	1 619 197	0	0	0	0	0	0	0	0	0
Amortization assesments 1 stage		3 613 702	2 821 394	2 202 800	1 719 834	144 744	113 009	88 231	68 887	53 783	41 991	32 785	116 745
Amortization assesments 2nd stage		1 146 583	895 193	698 921	545 682	45 925	35 856	27 995	21 857	17 065	13 323	10 402	37 042
Total revenue	0	4 772 983	8 482 027	9 188 044	9 188 044	9 188 044	9 188 044	9 188 044	9 188 044	9 188 044	9 188 044	9 188 044	9 188 044
Balance sheet profit	0	-4 334 421	-2 478 473	-1 440 175	-803 970	1 270 876	1 312 681	1 345 320	1 370 803	1 390 698	1 406 232	1 418 359	1 307 759
Income tax	0	0	0	0	0	25 418	26 254	26 906	27 416	27 814	28 125	28 367	0
Net profit	0	-4 334 421	-2 478 473	-1 440 175	-803 970	1 245 459	1 286 427	1 318 413	1 343 386	1 362 884	1 378 107	1 389 992	1 307 759
Cash flow	-16 482 027	-4 803 679	1 238 114	1 461 546	1 461 546	1 436 128	1 435 292	1 434 640	1 434 130	1 433 732	1 433 421	1 433 179	1 461 546
Money on the account	**-16 482 027**	**-21 285 707**	**-20 047 592**	**-18 586 046**	**-17 124 500**	**-2 659 725**	**-1 224 432**	**210 207**	**1 644 337**	**3 078 069**	**4 511 491**	**5 944 670**	**7 406 216**
Simple payback period		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**15.85**	**0.00**	**0.00**	**0.00**	**0.00**	
Simple payback period								**15.85**					
Discount factor	1	0.909	0.826	0.751	0.683	0.263	0.239	0.218	0.198	0.180	0.164	0.149	0.135
Discounted Cash flow		-4366981	1023235	1098081	998256	378178	343598	312219	283735	257869	234376	213033	197500
Discounted money on the account	**-16 482 027**	**-20849008**	**-19825774**	**-18727693**	**-17729437**	**-11648853**	**-11305255**	**-10993036**	**-10709301**	**-10451431**	**-10217055**	**-10004023**	**-9806523**
		0.00	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	
Discounted payback period													

Economic indexes

Net Pesent Value	**-9 094 566**	**Euro**
Internal Return Rate	**2.4%**	
Simple Payback Period	**15.9**	**years**
Discounted payback period	**>10**	**years**

Annex 3-8 LHC

new gas fired boiler	2009	2010	2011	2012	2013	2014	2015	2021	2022	2023	2024	2025	2026	2027	2028		
	1	2	3	4	5	6	7	13	14	15	16	17	18	19	20	Average	**LHC**
Produced heat, Gcal/a	132 975	132 975	132 975	132 975	132 975	132 975	132 975	132 975	132 975	132 975	132 975	132 975	132 975	132 975	132 975	2 659 507	1 132 094
Operating costs, Euro/a	2 319 572	2 319 572	2 319 572	2 319 572	2 319 572	2 319 572	2 319 572	2 319 572	2 319 572	2 319 572	2 319 572	2 319 572	2 319 572	2 319 572	2 319 572	46 391 448	19 747 827
Investment costs, Euro/a	5 178 581	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5 178 581	4 707 801
Income tax, Euro/yr																0	0
Specific cost of thermal energy, Euro/Gcal	78.86	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	19.39	**21.60**

old Gas fired boilers	2009	2010	2011	2012	2013	2014	2015	2022	2023	2024	2025	2026	2027	2028		
	1	2	3	4	5	6	7	14	15	16	17	18	19	20	Average	**LHC**
Produced heat, Gcal/yr	137 870	137 870	137 870	137 870	137 870	137 870	137 870	137 870	137 870	137 870	137 870	137 870	137 870	137 870	2 757 396	1 173 763
Operating costs, Euro/yr	2 374 735	2 374 735	2 374 735	2 374 735	2 374 735	2 374 735	2 374 735	2 374 735	2 374 735	2 374 735	2 374 735	2 374 735	2 374 735	2 374 735	47 494 695	20 217 455
Investment costs, Euro/a	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Specific cost of thermal energy, Euro/Gcal	24.09	24.09	24.09	24.09	24.09	24.09	24.09	24.09	24.09	24.09	24.09	24.09	24.09	24.09	17.22	**17.22**

New CHPP (heat)	2009	2010	2011	2012	2013	2014	2015	2022	2023	2024	2025	2026	2027	2028		
	1	2	3	4	5	6	7	14	15	16	17	18	19	20	Average	**LHC**
Produced heat, Gcal/yr	56 719	94 532	100 834	100 834	100 834	100 834	100 834	100 834	100 834	100 834	100 834	100 834	100 834	100 834	1 966 270	813 147
Operating costs, Euro/yr	2 246 157	3 742 930	3 992 281	3 992 281	3 992 281	3 992 281	3 992 281	3 992 281	3 992 281	3 992 281	3 992 281	3 992 281	3 992 281	3 992 281	77 850 149	32 195 079
Investment costs, Euro/a	8 516 263	2 702 105	0	0	0	0	0	0	0	0	0	0	0	0	11 218 368	9 975 202
Specific cost of thermal energy, Euro/Gcal	265.38	95.35	55.37	55.37	55.37	55.37	55.37	55.37	55.37	55.37	55.37	55.37	55.37	55.37	45.30	**51.86**

New CHPP (power)	2009	2010	2011	2012	2013	2014	2015	2021	2022	2023	2024	2025	2026	2027	2028		
	1	2	3	4	5	6	7	13	14	15	16	17	18	19	20	Average	**LPC**
Produced electicity, MWh/yr	151 549	252 582	269 421	269 421	269 421	269 421	269 421	269 421	269 421	269 421	269 421	269 421	269 421	269 421	269 421	5 253 706	2 172 659
Operating costs, Euro/yr	2 100 963	3 500 983	3 734 216	3 734 216	3 734 216	3 734 216	3 734 216	3 734 216	3 734 216	3 734 216	3 734 216	3 734 216	3 734 216	3 734 216	3 734 216	72 817 838	30 113 957
Investment costs, Euro/a	7 965 764	2 527 438	0	0	0	0	0	0	0	0	0	0	0	0	0	10 493 202	9 330 395
Specific cost of power energy, Euro/Gcal	66.43	23.87	13.86	13.86	13.86	13.86	13.86	13.86	13.86	13.86	13.86	13.86	13.86	13.86	13.86	15.86	**18.15**

Annex 3-9 Baseline scenario

Steam production was calculated on the base of heat produced, steam temperature and pressure values (http://www.dpva.ru/informations/Mtls/Gases/Steam/SaturatedSteam0to100bar/). All the other data were provided by the SE Tirotex.

old boiler house

	2005	2006	2007	2008 (1/2)	average
Heat (steam produced), MWh	213875	226214	232948	111960	224 346
NG consumption, ths.nm3	25946,7	27445,3	28187,4	13662,2	27 193
heat produced, Gcal/a	183 900	194 509	200 299	96 269	192 903
LHV, MJ/nm3	33,600	33,629	33,615	33,607	33,61
heat losses (own needs 8%)	14 712	15 676	16 024	7 702	
electricity consumption, MWh/a (2-4%)	5 026	4 061	4 606	2 432	
annual operational hours					
GM 50/14	7152	7152	1584	1632	
GM 50/14	2592	1752	3480	1536	
GM 50/14	-	-	4560	2424	
DE-25/14	2 568	1560	1536	528	
DE-25/14	72	1176	3216	264	
steam produced, t	328 982	347 960	358 318	172 217	345 087

boilers	annual maintenance hours	capacity, t/h
GM 50/14	150	50
GM 50/14	150	50
GM 50/14	150	50
DE-25/14	150	25
DE-25/14	150	25

steam characteristics	
boiling point, ^{0}C	197
pressure, bar	14
density, kg/m3	7,106
Specific enthalpy of saturated steam, kJ/kg	2787,79
Specific enthalpy of feeding water, kJ/kg	440,00

Annex 3-13

Questionnaire

For CHP construction based on the existing boiler house in Tiraspol city (The Republic of Moldova)

1. General information

1.1. Project applicant (client) – company, which will be CERs owner as a result of CDM project activity.

Name of company	**SE "TIROTEX"**
Ownership	
Address	**Tiraspol city, The Republic of Moldova**
Tel/fax	
e-mail	
Web-page	**www.tirotex.com**
Brief description of company activity, history, experience of project realization, similar to the project activity	**Production of cotton, mixed and knitted fabrics and other sewing goods**
Quantity of company workers and their qualifications	**6 thousand persons**
Contact person	**Mr. Ordin Vilor Mykolayovich**
Position	**General director**
Tel/fax	**+ 373 (533) 9-55-74**
e-mail.	**tiro@tirotex.com**
Tel/fax	**fax: + 373 (533) 2-28-49**

1.2. If CERs owner and the new CHP owner are the separate juridical persons, please copy above table for the CHP owner.

2. Object, that will be basic for CDM project realization

2.1. Project site (boiler house location) at which the CDM project has to be implemented.

Name (number) of boiler house	**Boiler house of SE "Tirotex"**
Address	**Tiraspol city, Oktyabrskiy promuzel**
Number of workers	**22 persons**

2.2. Description of existing energy equipment of boiler house (please, continue table if necessary):

№	Model of boiler	Installed capacity (Gcsl/hour, or MW)	Boiler efficiency (according to the regime-card), %	Fuel consumption (natural gas – ths. m^3/hour)	Year of operation starting
1.	GM-50/14 – 4 ones	110 MW	90	112640	1973
2.	DE-25/14 – 2 ones	27 MW	90	28800	1998

2.3. Production and releasing of thermal energy by boiler-house for last 3 years:

Year	Heat produced by boiler house, Gcal/year	Heat losses Gcal/year or %	Heat released to the consumers, Gcal/year	Heating (released to the consumers' side)	Heat energy tariff rubles/Gcal, rubles	Income from heat selling, rubles/year
1	2	3	4		5	6
2005	183 900	14 712	Hot water: Heating: Total:	22 328 (604)		
2006	194 509	15 676	Hot water: Heating: Total:	34 254 (779)	142,29	110 840,72
2007	200 299	16 024	Hot water: Heating: Total:	26 688 (619)	245,72	152 100,02
First six months of 2008	96 269	7 702	Hot water: Heating: Total:	13 146 (413)	281,62	116 309,06

*2.4. Annual consumption of fuel (natural gas**) by boiler-house for the last 3 years:*

Year	Consumption (ths. nm^3/year)	Low heat value, MJ/nm^3	Tariff, Rubles/1000 nm^3	Total investments, rubles/year
2005	25 946,672	33,600	677,54	17 579 908,15
2006	27 445,293	33,629	874,25	23 994 047,41
2007	28 187,412	33,615	896,18	25 260 994,89
First six months of 2008	13662,243	33,607	1103,16	15071639,99

** - if another fuel types are additionally used, please, copy and fill in the above table.

2.5. Consumption of electricity by boiler-house for the last three years:

Year	Consumption, kWh/year	Tariff, copecks/kWh	Total electricity purchasing cost, rubles/year
2005	5 026 482	0,41	2 060 857,6
2006	4 060 840	0,41	1 664 944,4
2007	4 606 000	0,398	1 833 188,0
1-ое полугодие 2008 г	2 432 000	0,437	1 062 784,0

2.6. – Please, indicate the location of other boiler-houses (if any) according to the paragraph 2.1.

3. Please, present the average annual electricity consumption by enterprise (or at least the installed capacity necessary for covering the consumption of electricity by the enterprise) – **electricity consumption for 2007 – 136 030 000 kWh.**

4. Production characteristics of the enterprise after CHP construction

Please, present the technical characteristics of the new CHP

Total installed power capacity, MW	**31**
Total installed thermal capacity, MW	**85**
Model and number of turbines (engines)	**8 engines TCG2032V16**
Annual operation of equipment, hours/year	**8600**
Efficiency (or coefficient of fuel utilization), %	**93**
Planned electricity production, kWh/year	**248 000 000**
Planned heat production, kWh/year	**201 600**
Consumption for own needs of boiler-house (CHP) after reconstruction	
- in electricity, kWh/year, or %	
- in heat, Gcal*hour/year, or %	
Whether existing boilers are to be used for heat production or not, and if “yes”, in what quantity (Gcal/year) and what boilers?	**NO**
Planned consumption of natural gas by new CHP, ths. nm^3/year	**56 563**

5. Financing of project measures:

Total investments	**20 million $**
Own investments	**4,3 million $**
Credit investments	**15,7 million $**
Lender (if any)	
Interest rate	**11 %**
Investment returning	**3 years**

6. Please, present the schedule of project realization (by months)

Receiving of permits	**till 10.11.2008**
Project works	**Projection stage (till 30.10.2008)**
Preparing works	**01.06.2008**
Construction works	**01.09.2008**
Starting-up and adjustment	**01.03.2009**
Starting of operation	**01.04.2009**

7. Stage of project realization:

Availability of feasibility study	**Yes**
Availability of business-plan	**Yes**
Availability of Environmental Impact Assessment	**Yes**
Availability of permits for construction from local governmental bodies: Ministry of fuel and Energy, Regional Energy Department, etc.	**No**
Did the construction begin?	**No**

8. Please, give the valid tariffs for the moment.

Tariff on electricity for the boiler-house, copecks/kWh	**0,438**
Supposed tariff on electricity, which will be sold by CHP to the Oblenergo grid or	

directly for consumers, i.e. wholesale tariff or tariff for direct delivery, copecks/kWh	
Tariff on heat released to the existing heat network, rubles/Gcal	
Natural gas price, rubles/1000 nm^3	**1103,16**
Natural gas price for the electricity production, rubles/1000 nm^3	**750,11**
Process water price, rubles/t	**0,74**
Average salary of CHP personnel (assignments, interest rate and overhead charges are not included), rubles/month/person	

Annex 4

MONITORING PLAN

The procedure describes all the necessary steps required for monitoring according to the requirements of monitoring methodology version 03 of AM0048. All necessary data required to be collected for calculation of GHG emission reduction, source of data collection and other data required in connection with implementation of this type of projects will be registered.

Quality assurance and control (QA/QC):

-A department that is responsible for operation of the CHP plant will be set up based on the existing subdivision of SE Tirotex. In the staff of this department a person will be assigned responsible – CER manager for the monitoring program namely data collection, archiving and quality control. The manager will prepare reports, as needed for audit and verification purposes. It is assumed to implement automatic monitoring, collection and processing of data every hour. In any case all measuring equipment has at least half a year independent (including energy independent) archive of measured data, which can be extracted and processed any time.

- SE Tirotex will designate a system manager to be in charge of and accountable for the generation of CERs including monitoring, record keeping, computation and recording of CERs, validation and verification

- The system manager will officially sign off on all worksheets used for the recording and calculation of CERs

-Well-defined protocols and routine procedures, with good, professional data entry, extraction and reporting procedures will make it considerably easier for the validator and verifier to do their work

- Proper management processes and systems records will be kept by the project. The verifiers can request copies of such records to judge compliance with the required management system.

- The monitoring manual will be compiled and working staff in the monitoring department will fulfill their responsibilities using this manual.

- the QC will be provided by continuous calibration of the meters and by invoices from gas, electricity companies for used/sold energy sources. Fixing calibrating or changing the meters will be done by an authorized company. All written documentation such as maps, drawings, the EIA and the Feasibility study should be stored and should be available to the verifier so that the reliability of the information may be checked.

- A formal set of monitoring procedures will be established prior to the start of the crediting period. These procedures will detail the organization, control and steps required for certain key monitoring features, including:

1. Staff training.
2. Monitoring equipment.
3. Data collecting and recording.
4. Data management.
5. Quality control and quality assurance.

Staff training

The CER Manager will be responsible for ensuring that the procedures are followed on-site and for continuously improving the procedures to ensure the reliability of the monitoring system.

All staff involved in the CER project will receive training from the monitoring team manager. The records of staff training will be retained by the Project Developer. The manager will ensure that only trained staff is involved in the operation of the monitoring system.

Required capacity and internal training will be equipped to the operational staff and the monitoring staff to enable them to undertake the tasks required by this Monitoring Plan. Appropriate staff training will be provided before this project starts operating and generating CERs.

All measured data are to be stored in the non-processed electronic form in the memory of measuring devices for at least half a year. Besides the processed measured and calculated values are to be stored in the electronic form in EXCEL sheets, and in paper.

Monitoring equipment

1. Data and source of data to be collected during on-site monitoring.

Gas meters
In compliance with the manufacturer's procedures gas engine cogeneration gensets (Deutz) at the new CHPP will be fitted with an automatic acquisition system. Readings of all sensors will be transferred to the control unit for further computer processing and archiving.
A separate natural gas meter will be installed at each gas engine. Data on consumed amount of natural gas will be regularly transferred to the control unit. Volume of natural gas consumed at the new CHPP under the project in the year y will be calculated as a sum of volumes of natural gas consumed by each gas engine in the year *y*. Data on monthly natural gas consumption will be regularly verified with the invoices received from the natural gas supplier.
Electricity output will be measured by electric meters installed at each genset. To determine net electricity generation at the new CHPP in the year *y* readings of a separately installed meter will be used, this meter will measure the amount of electricity delivered to the grid. Electricity output data will be regularly transferred to the control unit.
Net calorific value of natural gas will be analyzed by the fuel supplier. The fuel quality certificates will be provided on a monthly basis. Net calorific value of natural gas in the year *y* will be determined as an average value at the end of the year *y*.
A main gas consumption meter will be installed at the output end of the grid and a cross check meter at the input end of the plant. The main meter will determine the gas supply figure on the receipt of sales provided to the project developer by the gas company. The meters will be installed by the gas grid operator and will be in accordance with the local standards.

Electricity meters
Two electricity meters will be installed for establishing the electricity delivered to the project consumer and to the grid. The meters will be installed at the output end of the CHPP by the electricity grid operator and will be in accordance with the local standards.

Steam, temperature and pressure meters
Each heat recovery boiler will be equipped with the steam flow, temperature and pressure meters. Heat exchangers will be equipped by temperature gauges, flow meters and heat meters. The meters will be installed by the specialized local company in accordance with the local standards.
Metering signals from flow meters and temperature and pressure sensors will be delivered to computing systems and then to high level of automatized monitoring system.

In case there are modifications to the standards, the modified standard shall be valid; and in case a valid standard is cancelled or abolished, the new standard shall be valid. The meters will be factory calibrated by the manufacturer before installation. Records of the meter (type, make, model and calibration documentation) will be retained in the quality control system. Frequency of calibration of meters will be set up on accordance to the local standards.

Data on monthly energy consumption will be regularly verified with the invoices from the suppliers.

2. Data and source of data required for calculation of the baseline CO2 emission factor in the year *y*.
All data required for calculation will be monitored annually throughout the crediting period as per "Tool to calculate the emission factor for an electricity system", namely:
Net electricity generated and delivered to the grid by power plant/unit *j* in the year *y* and amount of fuel consumed by power plant/unit *j* in the year *y*. The source of data will be officially published statistical reports or information got from the National Committee of Statistics.
Net calorific value of fuels consumed by power plant/unit *j* in the year *y* if available. The source of data will be officially published statistical reports or information got from the National Committee of Statistics.
In case the National Committee of Statistics is not able for any reason to provide data on annual consumption of fossil fuel, this value will be estimated in a conservative manner. It will be assumed that only natural gas was used for power generation purposes at the plants and energy efficiency of power plants will be taken from the latest version of the "Tool to calculate the emission factor for an electricity system"

Automatized control and accounting system is to be implemented in the project facility. All measured parameters will be stored in electronic form of EXCEL sheets during 2 years with opportunity of diagram drawing.
Automatized control and accounting system consists of:

- electricity meters
- heat, water, steam, gas meters
- meter adapters
- electricity meters data collection concentrators
- remote concentrators with access to radiochannel
- interface converters with connection to optical fibre cable
- computer – data collection server
- 2 computers of duty operators
- radio modem for data exchange with remote concentrators
- computers – automatized work place of major specialists.

Data collecting and recording

Metering gas consumed by CHPP
The gas will be measured electronically and continuously.

Metering electricity delivered to the project customer and to the grid
The electricity will be measured electronically and continuously.

Metering of steam produced by CHPP
Metering of steam will be done electronically and continuously.

Meter failure
In case of meter failure, the cross check meter would be used until the main meter is fixed.

Data management
At the end of each month, the monitoring data needs to be input electronically into a spread sheet. The electronic files will have a CD back-up.
Order of calibration of the measurement equipment and conditions of the metrological control are described in the standard of SE “Tirotex” STP 13-19-2004. Extract of the standard was provided to AIE.

Annex 5

ENVIROMENTAL IMPACT ASSESSMENT
Project for Environmental Protection
Executive Summary

SE “Tirotex” is located at October unit in the east uptown of Tiraspol city, Republic of Moldova.
In the north and the east the enterprise is bordered on rural territory and in the south and the west Tiraspol city is located. Residential district is situated in the south at 700 meters’ distance from the enterprise (behind the railroad) and in the west at 1000 meter’s distance. Sanitary protection zone of the enterprise does not include any objects which locations are not allowed in this place.

This project will reduce the amount of fuel used to generate power in the energy system and as a result, bring about positive effect to the environment by reducing the amount of pollutants emitted into the atmosphere. At the same time, employment opportunities will be created. In addition, no negative effects on the environment are expected. In other words, this project coincides with policy priorities and strategies of economic, social, and environmental sectors of Republic of Moldova.

Expected positive environmental effects caused by this Project:

- **Global warming:** As it was mentioned before, this project will reduce the amount of fuel used to generate power in the energy system and as a result, having positive effect to the environment by reducing the amount of GHGs emitted into the atmosphere.
- **Climate and microclimate:**
  The CHP plant building will not cause any climate changes at the project site.
- **Flora and fauna:** There are is no protected flora and fauna within the company´s territory. The territory for CHPP building is covered just by weeds. The project building will not have any negative effects on flora and fauna.
- **Ionizing, thermal and electromagnetic radiations:** There are no ionizing, thermal and electromagnetic radiations at the project site. Ionize equipment is absent. Each boiler has cover with thermal insulation, and electric generator is enclosed into metal earthed housing that prevent electromagnetic radiation.
- **Replacement of power produced by old power system:** The project foresees installation of CHP units which are up-to-date technology. The cogeneration technology is more efficient than production electricity and thermal energy by boiler-houses and power stations, which already exist in Republic of Moldova, and allows curbing green house gas emissions.

Therefore, the project has positive impacts on environment and conforms to general environmental protection policies and principles of Republic of Moldova. Besides environmental benefits, this project will also have positive effect on local economy and social life. Certainly there are minor negative details that can be applied to the project, and which can be mitigated by adopting countermeasures:

- **Air pollution resulting from CHPP exhaust gases:** Operation of CHP plant will cause emissions of CO and NOx contained in flue gases. However, since CHP will be situated primarily far from households, and since the capacity of CHPP is small, these negative effects will not cause any serious problems. According to accounts, the concentrations of noxious gases will not exceed the maximum concentration limits. Adverse weather conditions (as rain, snow, flaw) will not make worse environmental safety of CHP plant operation. Therefore emissions of CHP plant operating will not cause damages on environment.
- **Noise and vibrations:** Installation of new gas-reciprocating engine power facility and ventilation installations cause noise and vibration. But designed noise insulation for CHP units will reduce the level of noise, and noise characteristics will meet the sanitary norms. Impact on CHPP operators is also minimal and within the sanitary norms. Also, considering the fact that CHPP will be installed on SE “Tirotex” territory, which is far from any residential or administrative

buildings, additional noise and vibrations will not cause negative social effect.

- **Other impacts:** Impacts on soil and water are also minimal. CHPP will require small amount of water and oil for the operation. Thus, no significant oil spills or water pollution is expected within the project. CHP plant building will not cause any dangerous engineering-geological processes so there will no damages for soil at the project site.