JOINT IMPLEMENTATION PROJECT DESIGN DOCUMENT FORM
Version 01 - in effect as of: 15 June 2006

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SECTION A. General description of the project

A.1. Title of the project:

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Title: Reduction of Greenhouse Gases by Gasification in the Zapad Region of Bulgaria
Version of the document: Version 02
Date of the document: 22/10/2012
Sectoral scopes: 01 and 04 (Energy industries and manufacturing industries)

Revision history of the PDD:

Version	Date	Comments
01	17/07/2012	PDD submitted to AIE for GSP
02	22/10/2012	Final version of PDD

A.2. Description of the project:

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The Project consists in the reduction of greenhouse gases emissions thanks to the switch from highly polluting solid and liquid fossil fuels used by industrial, public consumers and households to natural gas in the Zapad region. The use of methane implies several benefits (i.e. economic, environmental, technological and social) compared to the other energy sources currently used.
The fuel switch will be possible thanks to the construction of a gas transport and distribution network in the region. The project implies also the reconstruction of end-users' combustion installations in the industrial, public and administrative and residential sectors.

The gasification is carried out by RilaGas EAD that realizes and manages the overall gas network.
Rila Gas EAD is the holder of a 35-year renewable license, to develop and operate a Gas Distribution Network ("GDN") in the Region of Zapad, west Bulgaria. Rila Gas AD is 100 % owned by Acegas Aps, a large Italian regional utility group, and it has been formed in 2006, upon awarding of a gas distribution license, with the purpose of construction and management of the greenfield GDN project in the Zapad area.
The Project will strengthen gasification in Bulgaria by establishing a gas network in Zapad region, one of the less industrialized regions of the Country and contribute to reduce the Greenhouse Gases (GHG) emissions. Rila Gas EAD owns two licenses related to the Zapad region: one for the distribution of natural gas (since 2006) and one for the natural gas final supply to householders and industrial and commercial customers (since 2006). The licenses will last 35 years.

The production of ERUs will allow the issuance of better economic connection conditions to citizens, thus lowering this financial barrier. The period of ERUs issuance emissions is from 2008 to 2020.
The Municipalities involved in the gasification project are 22: Pernik, Vratza, Ihtiman, Radomir, Dupnitsa, Blagoevgrad, Sandanski, Roman, Simitli, , Kostenets, Dolna Banya, Sapareva Banya, Etropole, Boychinovtsi, Strumiani, Boboshevo, Nevestino, Kocherinovo, Krivodol, Gorna Malina, Bobov dol and Kresna

The following table shows the project's history.

Table A.1: The project's history

Steps	Date
Decision to participate the Tender (creation of a Joint Venture between Acegas-Aps S.p.A and Costruzione Dondi S.p.A)	06/12/2005 (date of investment decision)
Deliberation from the State Regulatory Energy and Water Commission	13/04/2006
Incorporation of Rilagas EAD	05/05/2006
Licenses for gas distribution and gas supply awarded by the State Regulatory Energy and Water Commission	03/10/2006 (starting date of the project)

Objectives of the project:

- switch from solid and liquid fuels, and electricity to natural gas;
- delivery of natural gas to the end-users by construction of a gas distribution network;
- reduction of greenhouse gas emissions and delivery of emission reductions under the Joint Implementation (JI) mechanism;
- reconstruction of the end-users' combustion installations which will be realized by the customers themselves with support from RilaGas;
- improvement of the energy efficiency.

Scope of the project

The scope of the project consists of the construction and subsequent concessionary operation of the natural gas transport and distribution network and gas supply to the end-users in the Zapad region.The potential consumers of natural gas are grouped in three sectors: industrial, public and administrative and residential sectors. The main differences among these three sectors are:

- the purpose of the used fuel (i.e.: production, commerce, residential use);
- the amount of the yearly energy consumption;
- the energy source alternative to the natural gas.

The overall investment includes about 69 km of transport network and approximately 868 km of distribution network for a potential catchment area of about:

- 111,402 residential end-users;
- 293 industrial users;
- 431 public and administrative users.

The total investment envisaged for the gasification program of the plan amounts to 112.5 M leva.
Currently, in the Zapad region the natural gas network is not present. Industry mainly uses coal, heavy fuel oil and gas oil, etc., while the public and private sectors use electricity, wood and coal.
The main environmental pollutants released into the air during the combustion of coal and gas oil are particulate matter, SO_X, NO_X, CO and CO_2.
With the construction of the gas distribution/transport network and the substitution of the fuels currently used with natural gas the air quality will improve. Gasification will also induce the reduction of the total quantity of energy used due to the increase of energy efficiency of the burner installations.

Time schedule of the project

The development of gasification project is divided in four phases and covers all the following 22 Municipalities, according to the Tender for the project activity (year 2005):

- Phase 1 - from 2007 up to 2016, including the construction of the natural gas distribution network to cover all the potential users (industrial, public and residential) of the following seven Municipalities: Pernik, Vratza, Ihtiman, Radomir, Dupnitsa, Blagoevgrad and Sandanski.
  The network investment realization will cover almost 100% of industrial and public/administrative sector, and about 50% of residential sector. The first users will be connected to the gas network in 2010;
- Phase 2 - from 2008 up to 2010, including the construction of the natural gas distribution network to cover only the industrial and public users of the following four Municipalities : Roman, , Simitli, Kostenets, Dolna Banya;
- Phase 3 - from 2009 up to 2011, including the construction of the natural gas distribution network to cover only the industrial and public users of the following seven Municipalities : Sapareva Banya, Etropole, Boychinovtsi, Strumiani, Boboshevo, Nevestino, Kocherinovo;
- Phase 4 - from 2010 up to 2012, including the construction of the natural gas distribution network to cover only the industrial and public users of the following four Municipalities : Krivodol, Gorna Malina, Bobov dol, Kresna.

After the first phase of network investments, the project will continue with the gradual acquisition of households and the response of citizens in terms of connection to the gas network will be monitored and assessed. This response will mainly depend by the financial limits of each citizen; the gas penetration in the residential sector is vital for the financial feasibility of the project.
The first works for the gas network realization start in 2007 in the towns of Blagoevgrad, Pernik and Vratza; works followed in the other towns: Dupnitsa in 2009, Sandanski in 2009/2010, Radomir in 2010. Ihtiman will start the network realization later, in 2020.
Delays occurred in the realization of the gas network. These delays are due especially to a lot of bureaucracy involved in each step of the investments in Bulgaria.
The rigidity of burocracy in the issuances of permits is time-consuming for the companies and it is a fundamental obstacle to the development of the gas supply market in Bulgaria.

The proposed project activity covers all the four Phases and the above mentioned 22 Municipalities.

The Municipality of Pernik is included in another JI project, Pernik District Heating project. The District Heating system includes one combined heat and power (CHP) plant that produces heat for the district heating, and steam for industry and power. As the RilaGas'clients are not connected to the District Heating system in Pernik, the "double counting" is not envisaged.

Technical details of the project

As regards the transportation/distribution networks and REMI and secondary shelters, the realization of these facilities is divided in four stages as shown in the following table:

Table A.2: Stages for the realization of the facilities

Stages	**UM**	**Quantity**
First Stage		
Transportation network-Feeder	km	7
Distribution network	km	763
REMI shelters	n°	3
Secondary shelters	n°	18
Second Stage		
Transportation network-Feeder	km	18

Stages	UM	Quantity
Distribution network	km	38
REMI shelters	n°	4
Secondary shelters	n°	-
Third Stage		
Transportation network-Feeder	km	32
Distribution network	km	46
REMI shelters	n°	4
Secondary shelters	n°	-
Fourth Stage		
Transportation network-Feeder	km	12
Distribution network	km	21
REMI shelters	n°	7
Secondary shelters	n°	-

Besides the facilities shown in Table A.2, the project includes also the connections and the gas meters for the industrial, public and administrative and residential end-users.

Contribution to sustainable development

The proposed project activity ensures a positive contribution to sustainable development in the environmental, social and economic sector. In particular:

- Environmental – the project activity will not have a negative impact on environment, but it will bring strong environmental benefits to the atmospheric conditions of the Zapad region, in terms both of improvement of air quality and reduction of GHG emissions. In particular, the reduction of the harmful emissions is realized in the gasification process through the construction of the gas distribution network and the replacement of the used fuels with natural gas. The emissions will be reduced thanks to the lower emission factor of natural gas in respect to the fuels it will substitute and thanks to the higher efficiency of new gas fired systems replacing older liquid and solid fuel systems. Replacing solid and liquid fossil fuels with natural gas results in a considerable reduction of dust and sulphur oxides. In particular, due to the high content of solid dust particles in Bulgaria, the reduction of dust emissions is very important in the assessment of the impact of gasification on the environment.
- Social development – the project construction and operation in the three consumer sectors will improve the working conditions and the living comfort of people and will have a long positive impact on health of people reducing the atmospheric emissions generated by fossil fuel combustion.
  Moreover, the project envisages the involvement of local stakeholders, such as the population to support the activity. Involving people in the JI project activity and informing them about the purpose of the project is an important consciousness raising about the problems related to Global Warming and sustainable behaviours;
- Economic development – the proposed project activity will be a significant investment in the seven towns, and it will create new job opportunities in the supply, installation, operation and maintenance fields increasing skills and know-how. Gasification will also induce the reduction of the total quantity of energy used due to the increase of energy efficiency of the new burner installations.

So, the project will also assist in creating employment in the project area for either skilled or unskilled labourers during the construction and operation of the project and it will mitigate air pollution and its adverse impacts on human health.

A.3. Project participants:

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RilaGas EAD, the project owner, part of the AcegasAps Group, SIL s.r.l, also part of the AcegasAps Group.
D'Appolonia S.p.A.is in charge for the JI registration procedure.

The project participants are listed as follows:

Party involved (*)	Legal entity(ies) project participants (as applicable)	Please indicate if the Party involved wishes to be considered as project participant (Yes/No)
Bulgaria (host)	Rilagas EAD	No
Italy	SIL s.r.l.	No
(*) Please, indicate if a Party involved is a host Party		

End-users involved in the project
As regards the end-users involved in the project, they invest in the reconstruction of the equipment and they generate the greenhouse gases (GHG) emission reductions through the gas fired equipment.
They waive any rights on GHG emission reductions as shown in the General Terms for the contracts for sale of natural gas by Rilagas EAD (art. 8, paragraph 5)[1] where it is stated that "User hereby agrees and accepts to waive any rights on the reduced greenhouse gas emissions (CO_2 for example) generated by the user due to the utilization of the methane supplied by the Seller / Rila Gas. The said reduced emissions generated by the User are part of the total volume of generated emissions of greenhouse gases generated during the entire process of gasification as the Distributor / Rila Gas is the investor and has practically implemented a project for reduction of the greenhouse gas emissions on the entire territory of West Region according to mechanism of the Kyoto Protocol and in compliance with the license granted for the sale and distribution of methane".

A.4. Technical description of the project:

A.4.1. Location of the project:

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The Project is located in the Zapad Region which is located in the western part of Bulgaria.
Its northern part embraces part of the western Balkans and the Pre-balkan hills, Mount Ihtimanska Sredna gora, and the Vitoscia, Luilin and Losenska mountains. Its height is very uneven and features a mountains, passes, hollows and river valleys.
In the south-west direction the boundary of the region is marked by Mount Ossogovo and Belassitza, while in the east it is marked by the Rila and Pirin mountain ranges.
The Zapad region comprises the provinces of Blagoevgrad, Vratza, Kyustendil, Montana, Pernik and Sofia-Region. The municipalities involved in the gasification project are 22: Pernik, Vratza, Ihtiman, Radomir, Dupnitsa, Blagoevgrad, Sandanski, Roman, Simitli, Kostenets, Dolna Banya, Sapareva Banya, Etropole, Boychinovtsi, Strumiani, Boboshevo, Nevestino, Kocherinovo, Krivodol, Gorna Malina, Bobov dol, Kresna . The land area of the Zapad region, excluding the areas of the municipalities already endowed with other licenses for the distribution of natural gas, is around 8,560 km^2.

[1] The General Terms for the contracts for sale of natural gas by Rilagas EAD including paragraph 5 (art. 8) has been approved by the Board of Directors of RilaGas on 08/10/2012.

The Zapad region comprises the following municipalities:
- Blagoevgrad, Kresna, Petric, Sandanski, Simitli and Strumiani – Province of Blagoevgrad;
- Vratza, Krivodol, Mezdra and Roman – Provinde of Vratza;
- Bobov dol, Boboshevo, Dupnitsa, Kocherinovo, Kyustendil, Nevestino and Sapareva Banya – Province of Kyustendil;
- Boicinovzi and Montana – Province of Montana;
- Pernik and Radomir – Province of Pernik;
- Bojuriste, Botevgrad, Gorna malina, Dolna Banya, Etropole, Ihtiman, Kostenets and Samokov – Province of Sofia-Region.

The project excludes the municipalities of Bojuriste, Botevgrad, Kyustendil, Mezdra, Montana, Petric and Samokov for which a license for the distribution of natural gas has already been issued, until cessation or revocation of such licenses.
The land area of the Zapad region, excluding the areas of the municipalities already endowed with licenses, is 8,563.19 sq. km (just over 3,306 sq. miles).

The geographical coordinates of the 22 Municipalities are shown in the following table:

Table A.3: Geographical coordinates of the involved Municipalities (Lat/Lon)

Municipality	Latitude	Longitude
Pernik	42°36'37" N	23°01'56" E
Vratza	43°12'17" N	23°32'56" E
Ihtiman	42°26'18" N	23°48'57" E
Radomir	43°32'47" N	22°57'49" E
Dupnitza	42°15'50" N	23°06'41" E
Blagoevgrad	42°01'21" N	21°05'42" E
Sandanski	41°33'40" N	23°16'42" E
Roman	43°08'49" N	23°55'28" E
Simitli	41°53'34" N	23°06'41" E
Kostenetz	42°18'29" N	23°51'29" E
Dolna Bania	42°18'41" N	23°45'56" E
Sapareva Bania	42°17'21" N	23°15'51" E
Etropole	42°50'04" N	24°00'03" E
Boichinovtzi	43°28'32" N	23°20'17" E
Strumiani	41°38'18" N	23°12'09" E
Boboshevo	42°09'01" N	23°00'00" E
Nevestino	42°15'20" N	22°51'14" E
Kocherinovo	42°05'10" N	23°03'27" E
Krividol	43°22'20" N	23°28'55" E
Gorna Malina	42°41'39" N	23°42'21" E
Bobov dol	42°21'53" N	22°59'52" E
Kresna	41°43'15" N	23°09'35" E

A.4.1.1. Host Party(ies):

>>
Republic of Bulgaria

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

>>
Provinces of Blagoevgrad, Vratza, Kyustendil, Montana, Pernik and Sofia Region.

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

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The proposed project activity includes the following 22 Municipalities: Blagoevgrad, Vratza, Sandanski, Pernik, Radomir, Dupnitsa, Ihtiman, Roman, Simitli, Kostenets, Dolna Banya, Sapareva Banya, Etropole, Boychinovtsi, Strumiani, Boboshevo, Nevestino, Kocherinovo, Krivodol, Gorna Malina, Bobov dol and Kresna.

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

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The project is developed in the Municipalities mentioned in section A.4.1.3 and shown in Figure A.1: Networks of these areas are connected by the existing high pressure main gas network crossing the area.

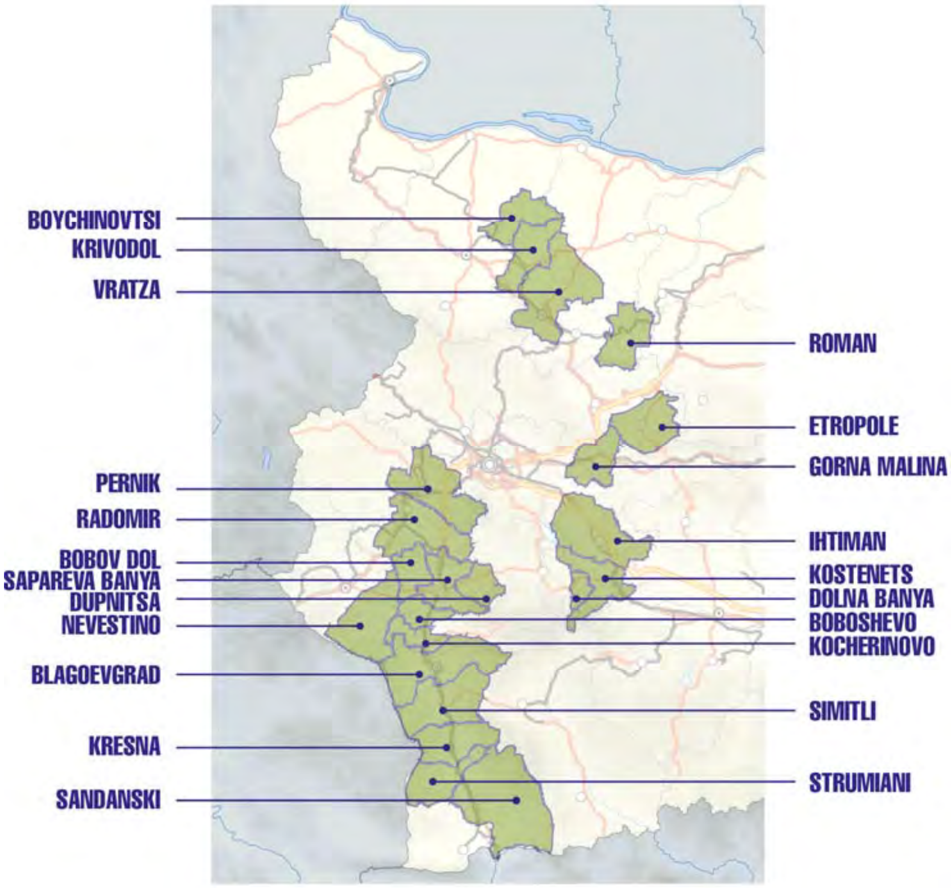

Figure A.1: The 22 Municipalities involved in the gasification project

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

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The Zapad region is crossed by the main gas pipeline of the northern loop with a diameter of 700 mm and pressure of 5.5 MPa (about 797 psi) and by branches (i.e. feeder lines) up to the automatic gas regulation stations (AGRS))/gas regulation stations with a diameter of 500 mm and pressure once again of 5.5 MPa. It is also crossed by the main gas pipeline of the southern loop with a diameter of 700 mm and pressure of 5.5 MPa and by branches up to the AGRS/gas regulation points with a diameter of 500 mm and pressure of 5.5 MPa, which supply industrial users, directly connected to the transport network and other users, directly connected to the distribution network.

The Zapad region is crossed by the gas transit pipeline with a diameter of 1,000 mm and rated operating pressure of 5.4 MPa. Two gas transit pipelines start downstream from the Piperovo purification station, one for Greece, with a diameter of 711 mm and rated operating pressure of 5.4 MPa and the second for Macedonia, with a diameter of 530 mm and rated operating pressure of 5.4 MPa. The operator of the transit network is Bulgargas EAD.

The gas transit pipeline in the Zapad region lacks high-pressure branches (i.e. feeder lines) and regulation stations. The gas pipelines going towards Greece and Macedonia have considerable free capacity, which significantly exceeds the region's natural-gas requirement.

The main gas pipelines and the branches already existing that cross the Zapad region are shown on the map in Annex 4.

In each of the areas of the project, the new network will consist of a main feeder linked to the existing high pressure line and in a medium and low pressure network. The main feature of the new networks within the project is the fact that they are designed to distribute gas at low pressure (500 mbar). After the main feeder from the high pressure network, gas will be supplemented with an odour substance to allow easy detection of possible leaks, and pressure will be reduced. The main pipelines will operate at intermediate pressure (16/5 bar), whereas the distribution at final customers will be done in low pressure (0.5 bar). These features make the project unique in Bulgaria, since it will be the first gas distribution system in Bulgaria operating at low pressure, with a much higher safety level. Again, it will be the first network with odour additive in the gas, with another safety increase.

Piping, fittings, measurement and pressure reduction stations will all be done following standards exceeding minimum Bulgarian standards. Pipework at high pressure will be realized in steel, whereas medium pressure pipes will be made of steel and HDPE.

The technology used in the realization of the natural gas network is a high quality European technology, in particular Italian and French equipment and know-how. The main suppliers which provided equipment and pipes used for the realization of the gas network are listed below:

- Automatic Gas Regulation Station (AGRS), Pressure Reduction Group (GRP), measurement and odorization stations, filters, gas odorization devices, heat exchanger: Pietro Fiorentini, an Italian company;
- Boilers in AGRS: Bongioanni, an Italian company;
- Gas meters, electronic volume conversion devices in AGRS: Elster, an Italian company;
- Gas meters for industrial, public and residential sectors: Elster, an Italian company;
- Flow and temperature adjuster devices: Elster, an Italian company;
- GRP for industrial and public users for gas flow > $25m^3/h$: Pegoraro, an Italian company;
- Pressure reducers for residential users for gas flow < $25m^3/h$: Mesura. Pressure reducers battery for gas flow > $25m^3/h$: Mesura, a French company
- Steel pipes: General Sider, an Italian company;
- Valves: Dafram, an Italian company;
- Dielectric Joints: Prochind / NuovaJungas, Italian companies.

The implementation of the project technology will imply a strong impact on GHG emission reductions, thanks to the low emission factor of natural gas and to the efficiency of gas fired equipment, in the substitution of other fossil fuels and of electricity.

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

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At present the combustion installations of the end consumers use solid and liquid fuels and electricity.
The solid and liquid fuels are characterized by high carbon dioxide emission factor and a large amount of greenhouse gases, together with micro-pollutants and their precursors (SOx, NOx,, NMVOC and CO) are emitted from their combustion. The switch from solid and liquid fuels to natural gas will result in significant reduction of the greenhouse gas emissions.
The project will also induce a reduction of electricity demand (and of the subsequent GHG emissions) as a result of the switch from electricity used for heating purposes and hot water preparation to natural gas. The emission reductions arising from the shift from electricity to natural gas will however not generate Emission Reduction Units (ERUs), since within the Bulgarian National Allocation Plan they are accounted within the EU-ETS scheme and considering them within the ERUs would induce indirect double counting.
The new gas network will allow the possibility of new power generation through high efficiency combined cycle or simple cycle gas power plants. This measure will also induce important reductions in GHG emissions, but also power generation is accounted within the EU-ETS scheme and considering them as ERUs would induce direct double counting.
Thus, only natural gas replacing fuels for combustion purposes will contribute to generate ERUs.
Emissions within these installations will be reduced thanks to:

1. the lower emission factor of natural gas in respect to the fuels it will substitute;
2. the higher efficiency of new gas fired systems replacing older liquid and solid fuel emissions.

As a result of the project implementation (incl. 2020) total **718,559 tCO_{2e}** greenhouse gas emissions reduction units will be generated as follows:

- In the period 2008-2012: **204,739 t CO_{2e}**
- In the period 2013-2020: **513,820 t CO_{2e}**

The implementation of the project under Joint Implementation mechanism is of substantial importance not only because of the funds that will be received from the emission reductions' sale. The availability of a validation report on the estimated project outcomes by an independent company and the approval of the project by the government of the Republic of Bulgaria through the Ministry of Environment and Water (MOEW) also facilitate the obtaining of loans from banks for funding the construction of gas distribution infrastructure.

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

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The table below indicates the annual emissions reduction in the period 2008-2012 (first crediting period):

Length of the crediting period	5 years
Year	Estimate of annual emissions reduction (tCO_{2e})
2008	13,194
2009	29,197
2010	47,822
2011	54,852

2012	59,674
Total estimated emissions reduction over the crediting period (tCO_{2e})	**204,739**
Annual average of estimated emissions reduction over the crediting period (tCO_{2e})	**40,948**

Between 2012 and 2020 (second crediting period), following the same calculations done for the first period, emissions will be reduced as indicated below:

Length of the crediting period	8 years
Year	Estimate of annual emissions reduction (tCO_{2e})
2013	61,775
2014	62,767
2015	63,609
2016	64,363
2017	64,959
2018	65,300
2019	65,476
2020	65,571
Total estimated emissions reduction over the crediting period (tCO_{2e})	**513,820**
Annual average of estimated emissions reduction over the crediting period (tCO_{2e})	**64,227**

A.5. Project approval by the Parties involved:

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The project has obtained all the needed authorizations from the National and local authorities and is being developed.

The project has received Letter of Support (LoS) issued by the Ministry of Environment and Water, dated February 2012 (Annex 5 - Letter of Support).

After completion of the validation of the Project Design Document, the PDD and the validation report will be submitted to the Ministry of Environment and Water (MOEW) with a request for issuing a Letter of Approval (LoA). Moreover, the PDD, the validation report and the Bulgarian LoA will be submitted to the Italian Ministry for the Environment, Land and Sea (IMELS) to obtain the Italian LoA before the first verification.

SECTION B. Baseline

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

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B.1.1 General Overview of Energy demand in Bulgaria

Bulgaria covers more than 70% of its gross energy demand by imports, this indicator being 76% for 2008 [2]. The dependency on import of natural gas and crude oil is practically full and has a traditional single origin, the Russian Federation. The Russian natural gas is supplied by one route through the Ukraine. Besides, Bulgaria relies completely on the import of nuclear fuel from Russia. The prevailing quantity of heat is produced on the basis of natural gas and the risks for the final consumers are much lower.

The dependency on imports in the electricity generation sector is considerably lower, 54%[1], mainly as a result of traditionally intensive use of indigenous lignite and hydropower.

The structure of the energy sources used for generation of electrical and heat energy in 2008, % on the basis of thousand tons of oil equivalent is shown in the following figure:

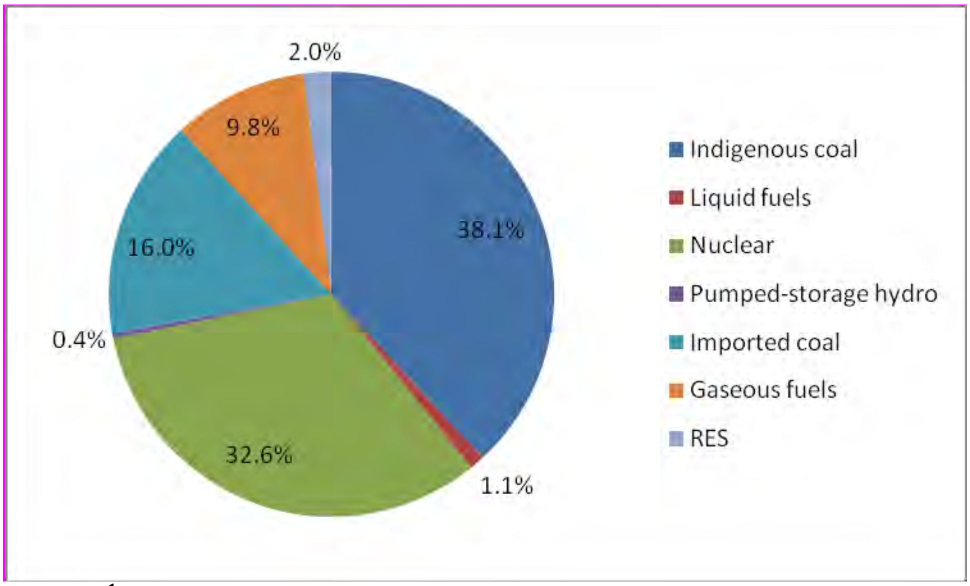

Figure B.1[1]: Energy Sources Used for Electricity and Heat Generation, Year 2008

The construction of a gas distribution network in the country is still at an initial stage. A priority of the Government is the development and extension of households' gasification in the country. Only 1.5% of the Bulgarian households have access to natural gas, while for Europe this percentage is 55%[1]. At the same time, almost 40% [1]of the energy used in the Bulgarian households (for heating and housekeeping) is electrical, while for Europe this percentage is 11%[1]. Replacement of electric energy with natural gas for domestic heating and housekeeping needs will contribute to three times higher savings of the primary energy. For this reason, natural gas should be viewed as one of the methods for the improvement of the energy saving, taking also into account that it is an ecological and less expensive alternative.

[2] Energy Strategy of the Republic of Bulgaria till 2020 for Reliable, Efficient and Cleaner Energy, June 2011

The sustainable economic growth over the recent years was accompanied by a trend towards energy intensity[3] decrease. Over the period 1999-2007 gross domestic product (GDP) grew by 5.3% per year on the average, while the gross domestic energy demand increased by 1.4% and that of electricity by 0.9%. As a result, the energy intensity per unit of GDP decreased by 25.4% [1].
Regardless of this positive trend, energy intensity of the national GDP is about 89% higher than the European average. This is an indicator of inefficient use of the primary energy resources, which is also corroborated by the relation between produced energy and the resources used in the production. This relation is 49% for the Bulgarian energy balance and 64% for Europe.

B.1.2 Energy sources used in the Zapad region

Data available to assess the emissions reductions due to the Project are mostly at national level. Data regarding the local situation come in part from the information included in the tender documentation for the construction of the gas distribution network and in part were collected and elaborated by Rilagas during the project design phase.
The Zapad region is crossed by a limited high pressure natural gas transportation network. Only a limited number of large customers is connected to this, since there are no distribution networks at municipal level. Due to this, the energy demand is dominated by other fuels (i.e. wood, coal, heavy fuel oil, gasoil and LPG) and electricity.
Industry mainly uses heavy fuel oil, gasoil, coal, natural gas, whereas the public and private sectors use electricity, wood and coal.

Solid fuels
Solid fuels are mostly represented by firewood and lignite.
Firewood is the most commonly used heating source in households; it is also used – to a much lesser extent – in the administrative/public sector and in the industrial sector.
Coal, and especially domestic lignite, is also used for space heating in the residential sector and in the public sector, but it is used more diffusely in the industry.

Liquid fuels
Liquid fuels are not very much used in the area. Apart for transportation, a reduced number of residential units use gasoil and LPG. Public and administrative buildings, as well as industrial installations, use both gasoil and heavy fuel oil.

Natural gas
Natural gas is currently used in a few locations in the area (i.e.: Pernik, Vratza, Ihtiman), mostly in the industry.
The end-users are directly connected to the natural gas transportation network of Bulgargas EAD and then they will not be involved in the Rilagas project activity.

Electricity
Electricity consumption is higher in Bulgaria than on the European average at all levels: industrial, commercial and residential. The absence of natural gas, in particular, makes electricity more used in Bulgaria than on the European average, especially for domestic hot water (DHW) production and for cooking in the residential sector.

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[3] The energy intensity is the ratio between an indicator for energy consumption , measured in energy units (J, toe, etc.) and an indicator for economic activity (GDP) measured in monetary units.

B.1.3 Approach used for baseline setting and monitoring

With reference to the "Guidance on Criteria for Baseline Setting and Monitoring", Version 03, the project proponent can select an approach for baseline setting and monitoring already taken in a comparable JI project. As comparable JI project, the "Reduction of greenhouse gases by gasification of Burgas Municipality"[4] project design document (Project ID: BG1000209), version 08, November 2007 has been considered. This approach has been chosen, since the determination of Burgas project is deemed final and the two projects can be considered comparable. Other very similar projects were registered as JI Projects in Bulgaria, namely projects with IDs BG1000150, BG1000151, BG1000152.
Data, assumptions, procedures and analyses within the documents of these projects having public evidence are approved by UNFCCC and can thus be considered as reliable benchmarks.
Comparing the present project with the Burgas one (BG1000209), the following conditions (required by the "Guidance on Criteria for Baseline Setting and Monitoring", Version 03) are satisfied:

- ***GHG mitigation measure:*** the project boundary of the proposed project and of Burgas project encompass similar sources of GHG emissions and the emission reduction are achieved by similar measures (i.e.: switch from liquid and solid fossil fuels to natural gas in the industrial, public and residential sectors);
- ***Geography and time***: the proposed project and Burgas project are hosted by the same Party and the period of time between starting dates of the two projects is not more than 5 years (Burgas starting date is year 2006 and the starting date of the proposed project is 03/10/2006);
- ***Scale:*** The proposed project and Burgas are similar in size comparing the emissions reduction achieved by the two projects in the period 2008 ÷ 2012 (about 316,000 tCO_2 for Burgas project and about 205,000 tCO_2 for the proposed project), with only a different time schedule in the project development;
- ***Regulatory framework:*** in the period between the starting dates of the proposed project and Burgas project the regulatory framework has not changed in a manner that would affect the baseline of this project.

B.1.4 Identification of the baseline scenario

The CDM methodology ACM 0009 "Consolidated baseline and monitoring methodology for fuel switching from coal or petroleum fuels to natural gas", Version 04.0.0 has been kept as guidance for building the baseline scenario and for the calculation of the emissions reduction resulting from the fuel switch.
The identification of the baseline scenario has been carried out as follows:

Identify all realistic and credible alternatives for the fuel use in the element process
The following alternatives are identified:

1. the project activity is implemented without selling the carbon credits under the JI mechanism (switching from coal or petroleum fuel to natural gas without the revenues of ERUs);
2. switching from coal or petroleum fuel to a different fuel than natural gas (such as biomass);
3. continuation of the current practice of using coal or petroleum fuel;
4. switching from coal or petroleum fuel to natural gas at a future point in time during the crediting period.

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[4] Available on the UNFCCCsite at:http://ji.unfccc.int/JIITLProject/DB/GO9CHSINN2I43CA344YBWPVG2W5UWV/details and on the MOEW web site: http://www3.moew.government.bg/?show=top&cid=357 (List of the approved Joint Implementation projects)

Eliminate alternatives that are not complying with applicable laws and regulations
All the above alternatives comply with applicable laws and regulations; in fact, both the alternative 1 and alternative 4 are closely related to the allocation of a tender by the Bulgarian government and then in accordance with the Bulgarian laws and regulations.
Alternatives 2 and 3 involve the use of the fuels currently used and then they are complying with applicable laws and regulations (alternative 3 foresees the continuation of the current practice).

Eliminate alternatives that face prohibitive barriers
The alternative 1 is not feasible: as it will be shown in section B.2, the investment barrier prevents the implementation of the project without the revenues of ERUs.
As regards Alternative 2, wood biomass is already very much used in the area, especially for space heating in households. In the past years, wood biomass substituted coal in this field. It is not realistic that industries can switch from coal and liquid fuels to biomass in a sustainable way, since there is no driver inducing such a change and since for many industrial processes this is not technically feasible. A possibility, especially valid for space heating in households and public structures, is the diffusion of automatic wood chip or pellet boilers, allowing the shift from traditional wood and coal fired domestic systems to systems offering a comfort similar to that of natural gas systems. Such biomass systems are however much more expensive and less reliable than natural gas, such that they also do not seem a realistic solution in absence of a strong incentive system.

The alternative 3 represents a plausible baseline scenario, facing no barriers. Fuels use in the industry and in the public sector will more or less remain the same of today, whereas the residential sector will gradually shift from coal and firewood to LPG or fuel oil following the gradual improvement of families' economic conditions and the subsequent thermal comfort demand.
For the analysis of alternative 3, the Bulgarian power grid has been taken as the baseline and baseline emissions have been calculated in accordance with the methodology.

The alternative 4 does not seem advantageous: there is no reason to suppose that in the future the financial and economic conditions for developing the region's gasification later will offer better conditions. From the technical point of view, the technologies related to gas distribution networks are mature and thus postponing the realization is likely not to offer better solutions. Moreover, since the gasification needs ERUs income to become feasible, delaying the start of the project implies a reduction of ERUs, thus worsening the financial performance of such a challenging, long term investment.

Then, the ***baseline scenario*** is the alternative 3, continuation of the current practice of using coal and petroleum fuel. This alternative complyies with applicable laws and regulations and do not face prohibitive barriers.

B.1.5 Calculation of the baseline emissions

The baseline emissions (BE_y) during the year y include the emissions of carbon dioxide (CO_2) released from the burning of solid and liquid fuels in the combustion installation in the industrial, public and administrative, and residential sectors, and the emissions from electricity that could be replaced with natural gas.
The emissions due to switch from electricity to natural gas are excluded form the emission reduction counting since they are already included in the EU-ETS scheme. The emissions from electricity replaced by natural gas are calculated using the following value for the carbon emission factor (CEF) of Bulgaria: 1.238 tCO_2/MWh. This value was calculated using the table "Baseline Carbon Emission Factor of Bulgarian Electricity and Heat Power System" (Annex 7) shown in the Ministry of Environment and

water (MOEW) website[5]. It is an average between the two highest baseline emission factor values related to the "fossil fuels Average Dispatch Data_OM_EF" (minimum and maximum demand cases) for year 2006 as shown in Table B.1.
The emissions EE_y from electricity replaced by natural gas are calculated as follows:

$$EE_y = E_{R,y} * EF_{CO2,ELEC,Y}$$

where:

$$E_{R,y} = FF_{project\ i,\ y} * NCV_{NG,Y} * \varepsilon_{project,i} / \varepsilon_{baseline,iy}$$

where:

EE_y =	Emissions from the electricity generation for year y replaced by natural gas in tCO_{2e}
$E_{R,y}$ =	Quantity of electricity replaced by natural gas in a respective sector without project implementation during the year y in MWh
$EF_{CO2,ELEC,Y}$=	Carbon Emission Factor of the replaced electricity in tCO_{2e}/MWh
$FF_{project\ i,\ y}$ =	quantity of natural gas combusted in the element process i during the year y in m^3
$NCV_{NG,Y}$ =	Average net calorific value of the natural gas combusted during the year y in GJ/m^3
$\varepsilon_{project,i}$ =	Energy efficiency of the element process i if fired with natural gas
$\varepsilon_{baseline,i,y}$ =	Energy efficiency of the element process i if fired with electricity

Tables including calculation of emissions due to switch from electricity to natural gas for the three sectors are shown in Annex 2, Baseline information.

Baseline emissions are calculated as the sum of the emissions of each fuel burned in the combustion installations.
The emissions released from the combustion of each fossil fuel are calculated based on the quantity of used fuel that would be combusted in each element process (i.e.: boiler) in the absence of the project activity and respective net calorific value and CO_2 emission factors.
The quantity of fossil fuels that would be used in each element process i ($FF_{baseline,i,y}$) in the absence of the project activity is calculated on the basis of the actual monitored quantity of natural gas combusted in this element process ($FF_{project,i,y}$) and the relation of the energy efficiencies and the net calorific values between the project scenario (use of natural gas) and the baseline scenario (use of coal, heavy fuel oil, gasoil and LPG) as shown in formula (3) and (4) below:

$$BE_y = \sum_i FF_{baseline,i,y} * NCV_{FF,i} * EF_{FF,CO2,i} \quad (3)$$

with:

$$FF_{baseline,i,y} = FF_{project,i,y} * NCV_{NG,y} * \varepsilon_{project,i} / NCV_{FF,i} * \varepsilon_{baseline,i,y} \quad (4)$$

where:

BE_y =	Baseline emissions during the year y in tCO_{2e}
$FF_{baseline,i,y}$ =	Quantity of coal or petroleum fuel that would be combusted in the absence of the project activity in the element process i during the year y in a volume or mass unit
$FF_{project,i,y}$ =	Quantity of natural gas combusted in the element process i during the year y in m^3
$NCV_{NG,y}$ =	Average net calorific value of the natural gas combusted during the year y in GJ/m^3
$NCV_{FF,i}$ =	Average net calorific value of the coal or petroleum fuel that would be combusted in the absence of the project activity in the element process i during the year y in GJ per volume or mass unit

[5] http://www3.moew.government.bg/files/file/Press/Kampanii/den_na_zemqta/memorandumi/Baseline_CEF_Summary2.pdf

$EF_{FF,CO2,i}$ = CO$_2$ emission factor of the coal or petroleum fuel type that would be combusted in the absence of the project activity in the element process i in $tCO_{2\,e}$/GJ
$\varepsilon_{project,i}$ = Energy efficiency of the element process i if fired with natural gas
$\varepsilon_{baseline,i,y}$ = Energy efficiency of the element process i if fired with coal or petroleum fuel

The baseline emissions are calculated by sectors as a sum of the emissions of each fuel burned in the combustion installations because of the different energy efficiency of the combustion installations and the different emission factors of the used fuels. Then, the total baseline emissions for each sector are calculated as follows:

Industrial sector: $BE_{total\_ind,\,y} = BE_{coal\_ind,\,y} + BE_{heavy\ fuel\ oil\_ind,\,y} + BE_{gasoil\_ind,y} + BE_{LPG\_ind,\,y}$

Public sector: $BE_{total\_public,\,y} = BE_{coal\_public,\,y} + BE_{heavy\ fuel\ oil\_public,\,y} + BE_{gasoil\_public,y} + BE_{LPG\_public,\,y}$

Residential sector: $BE_{total\_res,\,y} = BE_{coal\_res,\,y} + BE_{heavy\ fuel\ oil\_res,\,y} + BE_{gasoil\_res,y} + BE_{LPG\_res,\,y}$

The overall baseline emissions are the sum of the emissions of the three sectors:

$$\boldsymbol{BE_y = BE_{total\_ind,\,y} + BE_{total\_public,\,y} + BE_{total\_res,\,y}}$$

As shown in formula (3) and (4) above, the calculation of the baseline emissions and, in particular, the calculation of the quantity of coal or petroleum fuel that would be combusted in the absence of the project activity ($FF_{baseline,i,y,}$) is based on the quantity of natural gas combusted ($FF_{project,i,y}$). Since the baseline emissions are calculated by sectors as a sum of the emissions of each fuel burned, the $FF_{baseline,i,y,}$ are calculated for each fuel burned considering the quantities of natural gas that will replace coal or petroleum fuel.
These quantities are calculated based on a share of energy sources for each sector; this share provides the percentage of each fuel (i.e.: coal, heavy fuel oil, gasoil, LPG, wood, electricity) used in each sector. The yearly quantity of natural gas that will replace each energy source ,is calculated multiplying the percentage of each fuel by the yearly volume of natural gas.
$FF_{baseline,i,y,}$ is calculated multiplying $FF_{project,i,y}$ by a factor for conversion of natural gas into fossil fuels (this factor is = $NCV_{NG,y} * \varepsilon_{project,i} / NCV_{FF,i} * \varepsilon_{baseline,i,y}$). BE_y is calculated multiplying $FF_{baseline,i,y,}$ by NCV of fossil fuels and CO$_2$ emission factor of fossil fuels.
Tables including calculation of baseline emissions for the three sectors are shown in Annex 2, Baseline information.

Share of the energy sources for each sector
The share of energy sources for each sector used in the emissions reduction calculation is shown in the following table:

Table B.1: Share of energy sources by sector

Fuels	**Industrial sector**	**Public and administrative sector**	**Residential sector**
Coal	2.23%	13.41%	0.00%
Heavy Fuel Oil	67.57%	19.85%	0.00%
Gasoil	21.74%	46.15%	6.42%
Wood	0.00%	0.00%	0.00%
Electricity	8.08%	20.59%	20.59%
Natural gas	0.00%	0.00%	0.00%

Fuels	**Industrial sector**	**Public and administrative sector**	**Residential sector**
LPG	0.38%	0.00%	72.99%
Total	**100.00%**	**100.00%**	**100.00%**

As shown in table above, in the industrial sector the dominant fuel is heavy fuel oil followed by gasoil. Electricity, coal and LPG account for nearly 11%, a very low percentage compared to the other two dominant fuels.
As regards the public and administrative sector, the breakdown of fuels shows that gasoil is dominant followed by electricity, heavy fuel oil and coal; electricity, heavy fuel oil and coal account for about 54%.
In the residential sector the dominant fuel is LPG followed by electricity; they account for nearly 94%.
For more details about the estimation of share of energy source for each sectors make reference to Annex 2 – Baseline Information.
The volumes of natural gas combusted for the three different sectors are shown in the following table.

Table B.2: Volume of Natural Gas combusted per Year in the Three Sectors

Year	Industrial volume (Sm^3/y)	Public volume (Sm^3/y)	Residential volume (Sm^3/y)	Total (Sm^3/y)
2008	14,010,090	5,441,143	4,472,481	23,923,715
2009	30,984,282	11,394,416	12,876,745	55,255,443
2010	50,995,523	18,292,450	21,542,666	90,830,640
2011	58,134,973	20,094,731	30,412,773	108,642,477
2012	62,310,321	21,384,881	39,787,043	123,482,246
2013	63,448,619	21,730,271	48,180,668	133,359,559
2014	63,448,619	21,730,271	55,500,032	140,678,922
2015	63,448,619	21,730,271	61,712,189	146,891,079
2016	63,448,619	21,730,271	67,276,517	152,455,408
2017	63,448,619	21,730,271	71,676,077	156,854,967
2018	63,448,619	21,730,271	74,193,760	159,372,651
2019	63,448,619	21,730,271	75,490,782	160,669,673
2020	63,448,619	21,730,271	76,192,880	161,371,770
Total (Sm^3)	***724,024,145***	***250,449,792***	***639,314,613***	***1,613,788,550***

The natural gas volumes shown in Table B.3 will not be used, replacing fossil fuels, for power generation through high efficiency combined cycle or simple cycle gas power plants. Therefore, the GHG emission reductions obtained with the above mentioned volumes can be considered as ERUs, without inducing direct double counting.
Moreover, as regards the industrial sector, none of the industries that will be connected to the natural gas distribution network is included in the National Allocation Plan of Bulgaria[6].

The quantities of the yearly GHG emissions by sector released in the project area without implementation of gasification (baseline) are shown in the following table:

[6] National Allocation Plan for Allocation of Allowances for GHG Emission Trading for the Period 2008-2012, Sofia, 2010

Table B.3: Greenhouse gas emissions without project implementation - baseline

Year	Industrial sector (tCO_2)	Public and administrative sector (tCO_2)	Residential sector (tCO_2)	Total (tCO_2)
2008	34,150	11,627	7,460	53,236
2009	75,525	24,348	21,477	121,350
2010	124,303	39,088	35,931	199,322
2011	141,705	42,940	50,725	235,370
2012	151,883	45,696	66,361	263,940
Total (2008-2012)	**527,565**	**163,699**	**181,954**	**873,219**
2013	154,657	46,434	80,361	281,452
2014	154,657	46,434	92,569	293,660
2015	154,657	46,434	102,930	304,022
2016	154,657	46,434	112,211	313,302
2017	154,657	46,434	119,549	320,640
2018	154,657	46,434	123,748	324,840
2019	154,657	46,434	125,911	327,003
2020	154,657	46,434	127,082	328,174
Total (2013-2020)	**1,237,259**	**371,475**	**884,359**	**2,493,093**
TOTAL	**1,764,825**	**535,175**	**1,066,313**	**3,366,312**

Baseline emissions shown in Table B.4 do not take into account the emissions due to the replacement of electricity with natural gas which are shown at the end of Section E.4.

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

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The development of the natural gas network will induce citizens, public bodies and private enterprises to connect to it for their energy needs, satisfying with natural gas what is currently satisfied by other forms of energy. In particular, it is likely that most of the natural gas will be used for thermal purposes, substituting coal, heavy fuel oil and other liquid fuels, LPG, electricity and firewood. The impact on GHG emissions will be strong, thanks to the low emission factor of natural gas and to the efficiency of gas fired equipment, in the substitution of other fossil fuels and of electricity. Emissions reductions arising from the shift from electricity to natural gas will, however, not produce ERUs, since they are already included within the National Allocation Plan. On the other side, substitution of firewood with natural gas will increase GHG emissions (even if such shift reduces dust, CO, NOx and other polluting emissions).

This project is additional to any scenario that would otherwise occur. The most probable and the only alternative to the project activity is, as stated in Section B.1, the continuation of the current practice of using coal or petroleum fuel.

The development of the gasification process and the natural gas market depends on the following:

- the country's economic development;
- the end-users energy consumptions;
- the competitiveness of natural gas towards the other fuels.

The project includes the natural gas supply and its use by the end consumers from the industrial, public and administrative, and residential sectors. This project replaces the solid and liquid fossil fuels by natural gas and creates conditions for reducing the fuel consumption by introducing energy efficient technologies.
The end users in the three abovementioned sectors are the main fuels consumers. The replacement of solid and liquid fuels, which have a high carbon dioxide emission factor, with natural gas has the greatest effect on the reduction of GHG emissions. These emissions are released on-site the project, which covers the territory of Zapad region.
The leakages occurring during storage and transportation of solid and liquid fuels are not included in the baseline scenario and monitoring plan. They are minimal and are not included in the emissions calculation.

As regards the baseline emission factor of electricity, it has been calculated an average between the two highest baseline emission factor values related to the “fossil fuels Average Dispatch Data_OM_EF” (minimum and maximum demand cases) shown on table “Baseline Carbon Emission Factor of Bulgarian Electricity and Heat Power System” shown on MOEW website (see Annex 7). The baseline emission factor is 1.238 tCO_2/MWh equivalent to 344 tCO_2/TJ.
As previously mentioned, the emissions reductions arising from the shift from electricity to natural gas will, however, not produce ERUs, since they are already included within the National Allocation Plan.

The current installation in the three sectors are of different types and with different energy efficiency.The industrial and public sectors use boilers burning mostly heavy fuel oil and gas oil; a small part of the public sector uses boilers fed by coal.
The residential sector uses mostly coal-fired and wood-fired boilers and, to a lesser extent, boilers fuelled by propane and butane. The replacement of these boilers with gas-fired boilers will result in a considerable reduction of GHG emissions.
A further effect of gasification is the creation of favourable conditions for energy system optimization and the use of cogeneration, which reduces the end energy consumptions and, consequentely, the GHG emissions.

Additionality

With reference to the “Guidance on Criteria for Baseline Setting and Monitoring”, Version 03, Annex 1-A. Additionality, point 44, the project proponent, having identified a baseline, for the demonstration of additionality selected the approach (b): “provision of traceable and transparent information showing that the same approach for additionality demonstration has already been taken in cases for which determination is deemed final and which can be regarded as comparable, using the criteria outlined for baseline determination in paragraph 12”.
In fact, the same approach was already used in a comparable JI project for which determination is deemed final. As comparable JI project, the “Reduction of greenhouse gases by gasification of Burgas Municipality” project design document (Project ID: BG1000209), version 08, November 2007 has been considered. Burgas can be considered a comparable project, as demonstrated in Section B.1 (point B.1.3).

The construction of gas distribution networks in Bulgaria has started in the recent years and it was characterized by difficulties due to the lack of knowledge in the natural gas use, the need of large investments for the construction of gas distribution network and the low purchasing capacity of the population. The construction of gas distribution network and the delivery of natural gas to the residential sectors imply larger investments with longer pay-back period than the other sectors and need additional support.

Significant technological, investment, financial, cultural, legal and institutional barriers have prevented up to now the development of a large-scale switch to natural gas in the Zapad region.
The assessment of additionality includes the barriers analysis, the investment analysis and the common practice analysis as shown below.

1. ***Barriers analysis***

Technological barriers
The use of natural gas is new to nearly all future consumers on the territory of Zapad. Rilagas has to invest in training and education of the installers. It is fundamental to make an intensive public campaign in order to make the end-users aware of the safe and efficient use of natural gas.
The technical means for reconstruction of the combustion installations are not available to the installers and end-users, the skills to install gas pipelines are in a development stage and there is a shortage of skilled technicians and workmen in the gas sector. Therefore, it is necessary to develop large scale training and education of the installers and technicians to overcome this barrier.
The technology is new and needs to be adapted to the situation of the territory, for example in the use of natural gas in the existing apartment buildings. The installation of a new gas network in the area requires an adaptation of existing pipe laying technologies.
The use of natural gas is associated with safety risks, not only by the potential end-users but also by the local authorities; therefore, it is necessary to promote an intensive awareness campaign to overcome this barrier.

Investment barriers
The launching of a large scale project such as the gasification project of Zapad region requires large investments not only for the project proponent but also for the individual users who have to convert their installation to natural gas. The replacement of energy sources requires the purchasing of natural gas equipment by the end-users; part of the end-users should also adjust their installations to natural gas or build entirely new installations, ensure proper ventilation to guarantee the safe use of natural gas according to the existing regulations. The costs arising from new equipment may depend mainly on the type of heating system chosen, on the surface of the house and on upgrading or complete change of the installations currently used. To help the end-users to face the costs for the new installations, Rilagas, in cooperation with the banks, will propose a loan of 5-10 years at a very affordable rate and without warranty by the users.

As shown in Section A.3, the end-users generate the greenhouse gases (GHG) emission reductions through the new equipment fed by natural gas. They waive any rights on GHG emission reductions as shown in the General Terms for the contracts for sale of natural gas by Rilagas EAD, art. 8, paragraph 5 where it is stated that “User hereby agrees and accepts to waive any rights on the reduced greenhouse gas emissions (CO_2 for example) generated by the user due to the utilization of the methane supplied by the Seller / Rila Gas. The said reduced emissions generated by the User are part of the total volume of generated emissions of greenhouse gases generated during the entire process of gasification as the Distributor / Rila Gas is the investor and has practically implemented a project for reduction of the greenhouse gas emissions on the entire territory of West Region according to mechanism of the Kyoto Protocol and in compliance with the license granted for the sale and distribution of methane”.

Financial barriers
Financing of projects by private banks in Bulgaria is troublesome by the perception of high risk. The private banks will be less reluctant in financing the project when the project will be validated and the additional financial revenues under the Joint Implementation mechanism will be available. Guaranteed revenues from emission reduction sales will facilitate the arrangement of bank loans.

Cultural barriers

The current infrastructure is dedicated to the use of conventional solid and liquid fossil fuels. The potential users are familiar with all aspects in the use of solid and liquid fuels such as: prices, availability, appliances, risks and precautions. The awareness of the quality and advantages in the use of natural gas is still in an initial stage for most of the future users.

The end-users consider the use of solid and liquid fossil fuels as a standard practice and natural gas is perceived by most of the future consumers as new and risky. For nearly all end users the utilization of natural gas will be “a first of its kind” experience.

Legal barriers

The legislation is important to ensure the safe use of energy; the use of natural gas is new for most of potential consumers in Bulgaria. New regulations must be introduced, accepted, understood by the officials. Essential modifications of building regulations, for example, require long time to be designed and incorporated in the daily practice. All procedures for installation permits are slow and complicated and the rigidity of bureaucracy is time-consuming for the investors.

Institutional barriers

Apart from JI project revenues, there are not other subsidies available for the project in Bulgaria. The Bulgarian government has a policy to support only energy efficiency and renewable energy projects. This support does not include any financial incentives, neither for Rilagas EAD, nor for the potential end-users.

2. Investment analysis

In the following an investment analysis is provided to demonstrate the additionality of the proposed project activity.

The investment analysis will be carried out in order to determine whether the proposed project activity is not:

(a) the most economically or financially attractive;
(b) economically or financially feasible without the revenue from the sale of emission reduction units (ERUs).

For the choice of the approach to be used in the investment analysis, the project proponent referred to the “Guidelines on the Assessment of Investment Analysis, Version 05, Annex 5, EB 62” and in particular to section V Investmernt comparison analysis and benchmark analysis, point 19 of Guidelines. Point 19 states that “the benchmark approach is suited to circumstances where the baseline does not require investment or is outside the direct control of the project developer, i.e. cases where the choice of the developer is to invest or not to invest”.

Since the baseline is outside the direct control of the project developer and the project developer is not interested in investing in projects which do not foresee the use of natural gas, benchmark analysis has been chosen.

This option is appropriate because the relevant decision is to determine whether or not the project activity would be financially viable without the incentives of the ERUs. At this aim, as benchmark, the internal rate of return (IRR) will be used.

As mentioned above, the benchmark analysis is the option through which the project developer assesses and demonstrates the additionality of the project using the IRR as financial indicator.

For IRR calculation the project proponent referred to point 3 of the Guidelines on the Assessment of Investment Analysis, Version 05, Annex 5, EB 62 where it is stated that “the period of assessment should not be limited to the proposed crediting period of the CDM project activity. IRR calculations shall as a preference reflect the period of expected operation of the underlying project activity (technical lifetime), or, if a shorter period is chosen, include the fair value of the project activity assets at the end of the

assessment period. In general a minimum period of 10 years and a maximum of 20 years will be appropriate".
The project proponent has considered a period of 20 years (2007-2026) for the IRR calculation. This period is in accordance with the statement shown in the point 3 above; in fact, the period is shorter than the technical lifetime of the project (35 years), but it includes the fair value of the project activity assets at the end of the assessment period.
According to point 6 of the "Guidelines on the Assessment of Investment Analysis, Version 05, Annex 5, EB 62 the investment analysis carried out by the project proponent is based on input values and information valid and applicable at the time of the investment decision taken by the project participant, i.e.: 06/12/2005.
A benchmark appropriate to the country and sector has been selected. This benchmark has been calculated considering government bond rates (risk free) increased by a suitable risk premium (a specific country risk which takes into account equity risk, early stage development risk and specific country risk) to reflect private investment in fuel switching projects. These risks force the project equity investors to require significantly higher returns than the risk-free government bond.
In general, a **risk-free rate** is established and **risk premium** added on to account for investment specific risk because of the country risk.
For the purposes of this project, for the calculation of risk free rate the project developer refers to **6%**[7], which corresponds to the Bulgarian Government Bond annual interest rate, as shown in the document of Bulgarian National Bank "Government Securities Market, Primary Market of Government Securities". As this is an objective rate offered in Bulgaria, this serves as the ***risk-free*** return benchmark.
A risk premium is added, which is taken from the historical country risk classification rates published since 1999 by the Organization for Economic Cooperation and Development (OECD), and is given as **4%**[8] at the time of investment decision. As a result, an investor in the Bulgarian equity market should require a minimum return before specific project risks of **10%**.
The total investment reaches 57.7 M€ (112.5 Mlev, exchange rate: 1€ = 1.95 lev).
The total investment is covered as follows:

- Equity: about 14 M€ (27.3 Mlev);
- Debt: about 23.6 M€ (46 Mlev);
- Self- financing using cash-flows of the project: about 20.1 M€ (39.2 Mlev).

The financial analysis of the project shows that, for the period 2007-2026, the Internal Rate of Return (IRR) is 9.17%.
Internl Rate of Return (IRR)
The following parameters are used to calculate the IRR of the proposed project with and without the ERUs revenues.

Table B.4: Assumptions for financial analysis

ASSUMPTIONS		SOURCES
Gasification Project – Zapad Region		
Start operation date	03/10/2006 (when gas distribution and gas supply licenses were given to Rilagas EAD by the State Regulatory Energy and Water Commission)	

[7] http://www.bnb.bg/bnbweb/groups/public/documents/bnb_publication/public_bnb_p_gssm_200609_en.pdf, page 8 (BG 20 404 03219, fourth opening, issue maturity year 2018)

[8] http://www.oecd.org/trade/exportcredits/arrangementonexportcredits/cre-crc-historical-internet-rev1.pdf , updated 31/07/2012, page 37 of 85

ASSUMPTIONS			SOURCES
Technical lifetime of the Project (duration of licenses)	years	35	
Period used for the IRR calculation (2007 - 2026)	years	20	
Financial Assumption			
Equity	%	24.3	Financial and Industrial Plan 2007 - 2026 dated December 2005 (confidential)
Debt	%	40.9	Financial and Industrial Plan 2007 - 2026 dated December 2005 (confidential)
Self-financing	%	34.8	Financial and Industrial Plan 2007 - 2026 dated December 2005 (confidential)
Total Project costs (CAPEX) (1) (2)	Mlev / M€	112.5 / 57.7	Business Plan- December 2005 (confidential)
Fair value (3)	Mlev / M€	45.36 / 23.26	Business Plan- December 2005 (confidential)
Tax rate	%	15	Business Plan- December 2005 (confidential)
Interest rate	%	8	Business Plan- December 2005 (confidential)
Depreciation rate			
Gas transport network	%	4	Business Plan- December 2005 (confidential)
Gas distribution network	%	4	
Gas stations	%	6.67	
Building and offices	%	4	
Office equipment	%	20	
Operating &Maintenance cost			
O&M cost (4)	Mlev / M€	95.24 / 48.84	Business Plan- December 2005 (confidential)
Unit costs (2) (5)			
Transport network (high pressure)	lev/m €/m	98 50.3	Financial and Industrial Plan 2007 - 2026 dated December 2005 (confidential)
Distribution network	lev/m €/m	70 35.9	Financial and Industrial Plan 2007 - 2026 dated December 2005 (confidential)
REMI shelter	lev €	279,946 143,562	Financial and Industrial Plan 2007 - 2026 dated December 2005 (confidential)
Secondary shelter	lev €	47,331 24,272	Financial and Industrial Plan 2007 - 2026 dated December 2005 (confidential)

ASSUMPTIONS			SOURCES
Connection to the residential end-user	lev €	452 232	Financial and Industrial Plan 2007 - 2026 dated December 2005 (confidential)
Connection to the public/industrial end-user	lev €	6,700 3,436	Financial and Industrial Plan 2007 - 2026 dated December 2005 (confidential)
Project Revenues and Costs (2)			
Cost of natural gas purchased by Rilagas (VAT excluded)	lev/1,000 m^3 €/1,000 m^3	270 138.5	Business Plan- December 2005 (confidential)
Natural gas selling price for residential clients	lev/1,000 m^3 €/1,000 m^3	430 220.5	Business Plan- December 2005 (confidential)
Natural gas selling price for administrative clients	lev/1,000 m^3 €/1,000 m^3	377 193.3	Business Plan- December 2005 (confidential)
Natural gas selling price for industrial clients	lev/1,000 m^3 €/1,000 m^3	348 178.5	Business Plan- December 2005 (confidential)

(1) including the 22 Municipalities
(2) exchange rate: 1€ = 1.95 lev
(3) fair value of the project activity assets at the end of the assessment period (year 2026)
(4) total O&M cost on the period 2007-2026
(5) the unit costs (i.e.:cost of gas network, linear meter) have been estimated based both on an analysis about the average costs for gas network construction carried out in the area and on an analysis of the costs for similar project realized in Italy. In particular, as regards the transport and distribution network, the unit costs (linear meter) is an average value which takes into account: pipeline diameter, type of materials and type of dig.

The IRR is compared to the benchmark to assess the financial attractiveness of the project. From Table B.5, the IRR of 9.17 % is compared to the 10% expected return.
Project financial calculations show the IRR of the proposed project with and without the revenues of ERUs. As shown in Table B.5, without the revenues of ERUs the IRR is 9.17% which is lower than financial benchmark. Thus, the proposed project is not considered to be financially attractive without ERUs assistance; on the contrary, taking into account the JI revenues, the IRR is 10.15 %, which is higher than the financial benchmark. Therefore, the JI revenues enable the project to overcome the investment barrier and demonstrate the additionality of the proposed project.
The calculation of IRR with ERUs revenues has been carried out considering a price for ERUs of 8.80 $/tCO_2$ (year 2006)[9] which is equivalent to 6.98 €/ tCO_2 and to 13.61 Bulgarian lev/ tCO_2.
The following exchange rates were considered: 1€ = 1.26 $ as average value of year 2006 and 1€ = 1.95 lev.

Table B.5: Summary of the investment analysis, IRR without and with JI revenues

	IRR without ERUs revenues	Benchmark	IRR with ERUs revenues
IRR	9.17%	10%	10.15 %

Sensitivity analysis
The investment analysis shall include a sensitivity analysis which was performed to measure the impact of positive or negative changes in the specific performance parameters related to the project's performance. For the proposed project, the overall natural gas consumptions including the three sectors (industrial, public and residential) and the investment cost were selected as uncertain factors for sensitivity analysis of financial attractiveness:

1. overall natural gas consumptions including the three sectors;

[9] http://unfccc.int/files/cooperation_and_support/financial_mechanism/application/pdf/potential_of_carbon_matkets.pdf

2. investment cost.

According to the Guidelines on the Assessment of Investment Analysis Version 05, section VI sensitivity analysis point 21, financial analyses were performed altering each of these parameters by +/- 10% and assessing what the impact on the IRR would be.
The sensitivity analysis outcomes of the proposed project are shown in Table B.6 and in Figure B.2.

Table B.6: Sensitivity Analysis Outcomes (IRR values)

	-10%	-5%	0%	+5%	+10%
Overall natural gas consumptions (industrial sector+public sector+residential sector)	7.36%	8.27%	9.17%	10.06%	10.93%
Investment cost	10.18%	9.66%	9.17%	8.72%	8.30%

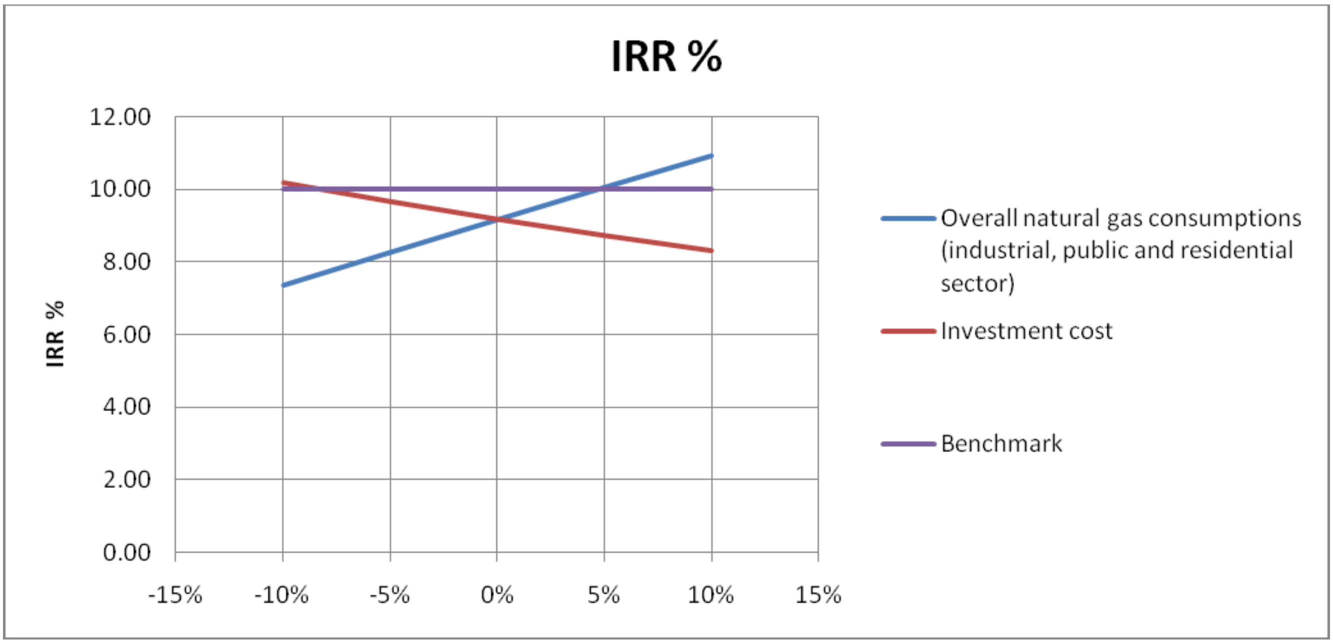

Figure B.2: IRR Sensitivity

As shown in Table B.6 and in Figure B.2, for each of these individual parameters, the probability for the IRR of overtaking the 10% IRR benchmark value could occur in the following scenarios:

- the overall natural gas consumptions should increase by 5% (and 10%);
- the investment cost should decrease by 10%.

It can be easily shown that these scenarios are not realistic. In fact, the overall natural gas consumptions cannot increase by 5% (and 10%) since currently the gas consumptions are by far lower if compared to the consumptions expected at the time of the investment decision. In fact, as regards year 2012, the current forecasts for gas consumptions are about 10 MSm^3, whereas the expected forecasts at the time of the investment decision were about 123 MSm^3.

The investmet cost cannot decrease by 10% since, currently, this cost has increased by more than 70% due to external contingencies (i.e.: the cost of raw materials) if compared to the cost at the time of the investment decision.
Therefore, the sensitivity analysis shows that the project actyivity is not feasible without JI revenues and then the support of ERUs is fundamental for the project activity.
It can be concluded that the project is not financially attractive for the project developer without ERUs benefits, and requires additional revenues from sale of ERUs to become viable. Hence, the ERUs revenues are critical to the successful implementation and operation of the project activity.

3. Common practice analysis

As shown in the barrier analysis, the end users consider the use of solid and liquid fossil fuels and the use of electricity as standard practice. For the end users the utilization of natural gas will be “a first of kind” experience; the switch to natural gas is “a first of its kind” project in the Zapad region and thus it does not represent a common practice.
Moreover, the proposed project can be considered the first that applies a different technology compared to other technologies which deliver the same output. In fact, the gas transport and distribution network is advanced and innovative both from a technological and a safety point of view for the following reasons:

- ✓ the natural gas is supplied to the end-users at low pressure (0.5 bar) and consequentely with higher safety standard compared to the other networks in Bulgaria which supply natural gas at medium pressure (4-6 bar) with higher risk from a safety point of view;
- ✓ the high pressure reduction stations are built in “remote-control” configuration, in order to allow a more flexible management of natural gas system and higher safety standards;
- ✓ an odorant to gas is added to ensure characteristic odor so that the presence of gas in air is readily detectable in case of gas leakages.

Conclusion

It has been demonstrated that the project faces technical barriers due to the lack of skill and technical means for the reconstruction of the combustion installations. Moreover, the skills to install gas pipelines are in a development stage and there is a shortage of skilled technicians and workmen in the gas sector. Therefore, it is necessary to develop large scale training and education of the installers and technicians to overcome this barrier.
The project faces investment barriers and requires investments not only for the project proponent but also for the individual users who have to convert their installation to natural gas. The costs related to the switch are an important financial and psychological barrier for the end-users. In fact, the additional investments in appliances, installations and their mounting which have to be made by the end-users are a serious barrier. In order to help the end-users to face the costs for the new installations, Rilagas in cooperation with the banks, will propose a loan of 5-10 years at a very affordable rate and without warranty by the users.
There is a lot of bureaucracy which is time-consuming and inefficient for the investors; for example, the rigidity of burocracy in the issuances of permits and laws are fundamental obstacles to the development of the gas supply market in Bulgaria.
Apart from JI project revenues, there are not other subsidies available for the project in Bulgaria.
The IRR of the project without JI revenues on the period 2007-2026 is below the 10% benchmark IRR and then this demonstrates the necessity of using ERUs for JI project (with ERUs revenues the IRR is 10.15%).
The revenues from the sale of emission reduction units will support in providing for the needed financing and will give an opportunity for introducing natural gas in the residential sector.
The revenues from the sale of ERUs will act as a special kind of catalyst for the fuel switch.
The end-users consider the use of solid and liquid fossil fuels as a standard practice and natural gas is perceived by most of the future consumers as new and risky; for nearly all end users the utilization of natural gas will be “a first of kind” experience.

The proposed project “Reduction of Greenhouse Gases by Gasification in the Zapad region of Bulgaria” is not “business as usual” for the territory, but it is “a first of its kind” project in the Zapad region and thus it does not represent a common practice. This highlights its additionality without any doubt.

Therefore, based on the barriers analysis, the investment analysis and the common practice analysis, it can be concluded that the project can be considered ***additional.***

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

>>

Direct on-site emissions

Direct on-site greenhouse gas emissions of the project are:

- Emissions released by the end-users’ combustion installations;
- Emissions released due to leakages during transportation and delivery of fuels.

The reduction of direct on-site emissions will be achieved by:

- Fuel switch at the end-users;
- Optimization of the combustion process and energy systems;
- Elimination of leakages during fuels’ storage, transportation and delivery.

Rilagas will use innovative methods and materials for the construction of gas distribution networks. This type of networks does not have dismountable joints, it is fully leak tight and the leakages are insignificant. Emissions caused by the leakages of natural gas from the gas distribution networks have been excluded from the calculation.

Direct off-site emissions

Direct off-site emissions are caused by the replacement of the electricity with natural gas. As mentioned in Section A.4.3, these emissions will not be taken into account; in fact, the emission reductions arising from the shift from electricity to natural gas will however not generate Emission Reduction Units (ERUs), since within the Bulgarian National Allocation Plan they are accounted within the EU-ETS scheme and considering them within the ERUs would induce indirect double counting.

Indirect on-site and off-site emissions

The indirect on-site and off-site emissions may be characterized as follows:

- emissions during the production and processing of fuels;
- emissions during the production of metals, transport vehicles and tanks for transportation and storage of fuels;
- emissions during the transportation and disposal of fuel wastes.

The control of these emissions is outside of the scope of the project and therefore they are excluded from the calculation.

Project boundaries

The project includes the natural gas supply and its use by the end-users from the industrial, public and administrative, and residential sectors. The implementation of the project will result in gradually replacing solid and liquid fuels with natural gas.

The project boundaries include on-site emissions of the combustion installations of the abovementioned sectors in each of the twenty-two Municipalities in the Zapad region, excluding the sites gasificated before the starting date of the project.

Table B.7: Sources and gases included in the project boundary

	Source	Gas	Included ?	Justification / Explanation
Baseline	Burning of solid and liquid fuels	CO_2	Yes	Main GHG emission source.
		CH_4	No	Small GHG emission source .
		N_2O	No	Small GHG emission source
Project Acitivity	Burning of natural gas	CO_2	No	Main GHG emission source.
		CH_4	No	Small GHG emission source
		N_2O	No	Small GHG emission source
Project Acitivity	Generation, transportation and distribution of electricity that will be replaced	CO_2	No	Excluded for double counting reasons

The block scheme of the project with its main parts and connections and the project boundaries are shown in Figure B.3a and Figure B.3b. Figure B.3a shows the situation before the fuel switch, whereas Figure B.3b shows the situation after the fuel switch.

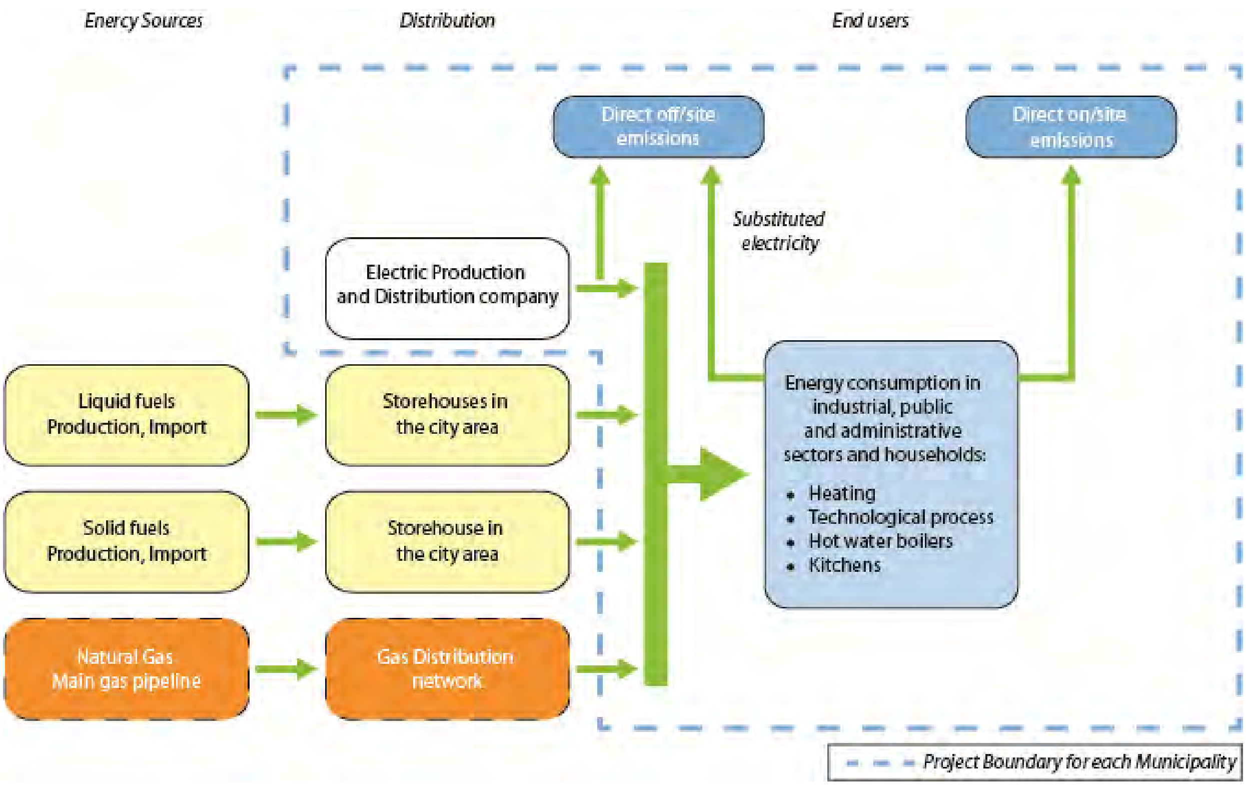

Figure B.3a: Block scheme of fuel delivery before gasification

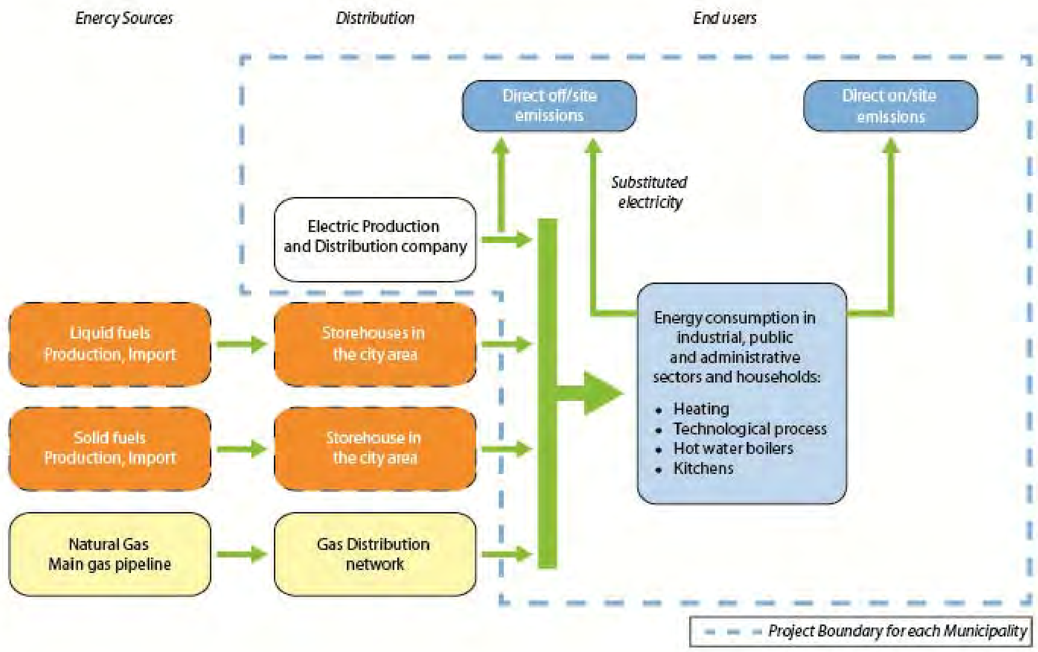

Figure B.3b: Block scheme of fuel delivery after gasification

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

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Date of baseline setting: 02/07/2012
Name of the entity setting the baseline: RilaGas EAD
Contact information of RilaGas EAD:
Street/P.O.Box: 36, Alabin Street
City: Sofia
Postal code: 1000
Country: Bulgaria
Phone: +39 049 8200 405
Fax: +39 049 8200 384
E-mail: rsilvoni@acegas-aps.it

RilaGas EAD is a Project Participant listed in Annex 1.

SECTION C. Duration of the project / crediting period

C.1. Starting date of the project:

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03/10/2006, date when gas distribution and gas supply licenses were issued to Rilagas EAD by the State Regulatory Energy and Water Commission

C.2. Expected operational lifetime of the project:

>>

The expected operational lifetime of the project is 35 years and 0 months, according to the licenses for distribution and supply of natural gas given to Rilagas EAD by the State Regulatory Energy and Water Commission

C.3. Length of the crediting period:

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- The length of the crediting period is five years and 0 months. The starting date of the crediting period is 01/01/2008;
- The crediting period can extend beyond 2012 (for eight years starting in the year 2013) only if it will be available an appropriate positive decision of UNFCCC and the approval by the host Party. The crediting period does not extend beyond the operational lifetime of the project.

SECTION D. Monitoring plan

D.1. Description of monitoring plan chosen:

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According to the "Guidance on Criteria for Baseline Setting and Monitoring", Version 03, the JI specific approach has been chosen for the monitoring plan.
The objective of the monitoring plan is to ensure the complete, consistent, clear and accurate monitoring and calculation of the emissions reductions during the whole crediting period. The project owner will be mainly responsible for the implementation of the monitoring plan and for monitoring of project data. Data to be monitored are:

- sales of natural gas in the industrial sector;
- sales of natural gas in the public and administrative sector;
- sales of natural gas in the residential sector;
- amount of natural gas purchased by Bulgargas AD;

The total annual natural gas consumption of the end-users by sectors will be used as an indicator to control and determine the greenhouse gas emissions with project implementation. This approach is used since:

- all currently used fuels will be replaced by natural gas;
- in the absence of this project the end-users would use fuels different from natural gas.

In the PDD the yearly consumption of natural gas and the resulting CO_2 emissions reduction for each sector are known. By dividing the emissions reduction by the yearly natural gas consumption, a factor is obtained quantifying the efficiency of the fuel switch from carbon rich fossil fuels to natural gas. This factor is named "Fuel switch emission reduction factor (FSERF)" and it will be used in the monitoring procedure. This factor is measured in tCO_{2e}/ 1,000 Sm^3.
The FSERF, calculated according to the formula shown in Section D.1.4, is used for each sector to convert natural gas sales by sectors in emission reduction units. The FSERF includes the fuel switch effect and reduced energy consumption due to the increase of the efficiency of the combustion installations.
The project monitoring includes the following stages:
• Monitoring of the project emissions and of the generated Emission Reduction Units (ERUs);
• Monitoring of the baseline;
• Monitoring of the leakages (only those due to unexpected accidents).

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

Monitoring of the project scenario emissions
The project emission monitoring activities are performed in the following sequences:

- Measuring the amounts of natural gas sold by the three sectors;
- Calculation of the generated emission reductions;
- Calculation of the Fuel Switch Emission Reduction Factor (FSERF).

Measurements of natural gas quantities sold by sector
According to the main principles of the monitoring plan, the main indicator for the ERUs quantity is the natural gas sales. Natural gas quantities are measured in cubic meters at Standard conditions.
The standard conditions of natural gas used in Bulgaria are 293.15 K (20 °C) and 1.01325 bar. Then, cubic meters at "Standard conditions" means the quantity of natural gas in a volume of 1 m^3 at a

temperature of 20°C and at an absolute pressure of 1.01325 bar. To transform the measured quantities of natural gas into standard conditions it is used an“electronic volume conversion device”.
The electronic volume conversion device consists of three main components, a transducer which detects the pressure (pressure transducer), a transducer which detects the temperature (temperature transducer) and a suitably programmed electronic computer which, taking into account the data detected by the two transducers, the data of the fluids to be processed , suitably stored, processes the pulses corresponding to the volumes measured by the counter and converts them into standard volumes (ref. at 20° C).
To transform the measured quantities of natural gas into standard conditions two methods are applied:

- by using an electronic volume conversion device;
- by multiplying the volume read on the consumption meter counter by a fixed coefficient determined depending on the meteorological characteristics of the respective region.

In particular, the measurement of natural gas quantities delivered to the residential and small commercial users (with 100 mbar pressure and with maximum hourly consumption of less than 25 m^3/h) is done with a fixed coefficient depending on the meteorological characteristics of the respective region (see also Annex 3 of the PDD).

General terms and conditions for natural gas sales
The conditions and the order for reporting the quantities of natural gas sales is regulated by the “General terms for the contracts for sale of natural gas by RilaGas EAD” and by the “Contract on the sale of natural gas to the industrial, public and administrative and residential consumers”.

General terms for the contracts for sale of natural gas by RilaGas EAD
According to the General terms for the contracts for sale of natural gas by RilaGas EAD, the recording of the quantities of sales of natural gas is performed by flow meters included in the State Register of the means for measurement approved for use in the Republic of Bulgaria.
In the General terms for the contracts for sale of natural gas by RilaGas EAD are also included the procedures for the gas meters reading. RilaGas EAD has the duty to carry out the gas meter reading monthly, according to a fixed schedule.

Contract on the sale of natural gas to the industrial consumers
According to the Contract on the sale of natural gas to the industrial consumers, RilaGas representatives must read the sold quantities of natural gas using the readings of the commercial gas flow meters on the first day of the month following the month of supply in compliance with the Rules on the trade in natural gas.
The quantity of natural gas supplied and used for the calendar month shall be established in a signed bilateral act each month. The monthly act is to be drafted on the first working day after expiry of the month by authorized representatives of the parties (RilaGas EAD and industrial consumers).
After expiry of each calendar year, authorized representatives of RilaGas EAD and industrial consumers shall sign an annual act for natural gas consumptions on the basis of the monthly acts signed during the year.

Contract on the sale of natural gas to the public and administrative and residential consumers
According to the Contract on the sale of natural gas to the public and administrative consumers, the reading and billing of the consumption of gas is carried out monthly by Rilagas.

The monitoring of the GHG emissions during the project implementation includes supervising and determining the emissions released by the natural gas burning in the combustion installations of the end-users. Indicators for the quantity of GHG emissions are the amount of purchased gas received in the gas distribution network and the amount of sold natural gas.

D.1.1.1. Data to be collected in order to monitor emissions from the project, and how these data will be archived:								
ID number *(Please use numbers to ease cross-referencing to D.2.)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
P1	Sales of natural gas in the industrial sector ($FF_{project, NG\_ind,y}$)	Monthly acts and annual act for natural gas deliveries between Rilagas EAD and the industrial consumers	Sm^3	m	Monthly and yearly	100%	Electronic/ paper	Data to be monitored throughout the crediting period
P2	Sales of natural gas in the public and administrative sector ($FF_{project, NG\_public,y}$)	Monthly reading and invoice of natural gas consumptions carried out by Rilagas EAD	Sm^3	m	Monthly	100%	Electronic/ paper	Data to be monitored throughout the crediting period
P3	Sales of natural gas in the residential sector ($FF_{project, NG\_res,y}$)	Monthly reading and invoice of natural gas consumptions carried out by Rilagas EAD	Sm^3	m	Monthly	100%	Electronic/ paper	Data to be monitored throughout the crediting period
P4	Amount of natural	Monthly acts	Sm^3	m	Monthly and	100%	Electronic/	Data to be

D.1.1.1. Data to be collected in order to monitor emissions from the project, and how these data will be archived:								
	gas purchased from Bulgargas AD	and annual act for delivery between Rilagas EAD and Bulgargas EAD			yearly		paper	monitored throughout the crediting period
P5	Net Calorific Value of natural gas ($NCV_{NG,y}$)	Reference by Bulgargas EAD for sales by invoices	GJ/Sm^3	e	Monthly	100%	Electronic/ paper	RilaGas accepts this value without measuring it. RilaGas monthly checks if this value matches the value specified in the contract with Bulgargas.

Conservativeness of CO_2 Emission Factor, Net Calorific Values and Energy Efficiencies

The choice of CO_2 emission factor, net calorific and energy efficiencies values was carried out by the project proponent in order to choose the most conservative values which minimize the emission reductions. The process has involved the following steps:

1. first step: values shown in the Burgas project “Reduction of greenhouse gases by gasification of Burgas Municipality” project design document (Project ID: BG1000209), version 08, November 2007 have been assumed as conservative, since Burgas is a registered project;
2. second step: the project proponent also considered,where applicable, the values of CO_2 Emission Factor, Net Calorific and Energy Efficiencies provided by IPCC 2006, ACM0009 Methodology and the Bulgarian National Greenhouse Gas Inventory Report (MOEW, 2011) for the country specific values and compared them with Burgas values in order to check if these values are more conservative (i.e.: higher or lower value, depending on the specific parameter) than the Burgas values;
3. third step: to identify which parameters should be lower or higher than those of Burgas, the project proponent combined the formulae used for the emission reductions calculation shown in the ACM0009 Methodology (project emissions formulae (1), (2), baseline emissions formulae (3), (4); leakages are considered negligible).

   After combination of formulae (1), (2), (3), (4) the formula for the emission reductions calculation becomes:

   $ER_y = \sum_i FF_{project,i,y} * NCV_{NG,y} *(\varepsilon_{project,i}/* \varepsilon_{baseline,i} * EF_{FF,CO2,i} - EF_{NG,CO2,y})$

Combining formulae (3) and (4) it can be deduced that $NCV_{FF,i}$ (Average net calorific value of the coal or petroleum fuel that would be combusted in the absence of the project activity in the element process *i* during the year *y* in GJ per volume or mass unit) has no influence on the emission reduction calculations.

Considering the formula for emission reductions calculation shown above, it is clear that the emission reductions are minimized if:

- $NCV_{NG,y}$ (Average net calorific value of the natural gas combusted during the year *y* in GJ/m³) value provided by IPCC 2006, or ACM0009 Methodology, or Bulgarian National Greenhouse Gas Inventory Report is lower than Burgas value;
- $\varepsilon_{project,i}$ (Energy efficiency of the element process *i* if fired with natural gas) value provided by IPCC 2006, or ACM0009 Methodology or Bulgarian National Greenhouse Gas Inventory Report is lower than Burgas value;
- $\varepsilon_{baseline,i}$ (Energy efficiency of the element process *i* if fired with coal or petroleum fuel) values provided by IPCC 2006, or ACM0009 Methodology or Bulgarian National Greenhouse Gas Inventory Report are higher than Burgas value;
- $EF_{FF,CO2,i}$ (CO_2 emission factor of the coal or petroleum fuel type that would be combusted in the absence of the project activity in the element process *i* in t CO_2/GJ) values provided by IPCC 2006, or ACM0009 Methodology or Bulgarian National Greenhouse Gas Inventory Report are lower than Burgas value;
- $EF_{NG,CO2,y}$ (CO_2 emission factor of the natural gas combusted in all element processes in the year y in t CO_2/GJ) value provided by IPCC 2006, or ACM0009 Methodology or Bulgarian National Greenhouse Gas Inventory Report is higher than Burgas value;

The CO_2 emission factors, net calorific values and energy efficiencies values including the conservativeness are shown respectively on Table D.1, Table D.2 and Table D.3.

Table D.1: CO_2 Emission Factor for Energy Sources

For the determination of CO_2 Emission Factor, values from IPCC Guidelines and Project ID BG1000209 (Burgas) have been used. The CO_2 Emission Factor of coal has been calculated as a weighted average value among a mix of different coal types.

Fuel	***Emission factor -EF*** $_{FF,CO2,i}$ **(tCO_2/GJ)**	**Source**	**Comment**	**Conservativeness**
Coal	0.0918	A weighted average value among brown coal, hard coal, lignite and coke emission factors. This value has been calculated considering the values of emission factors and net calorific values of the different types of coal shown on the 2006 IPCC Guidelines for National Greenhouse Gas Inventory and tons of coal provided by the National Statistic Institute (NSI). IPCC values at the lower 95% confidence interval have been considered ,as recommended in the ACM0009 Methodology	Data that is not monitored throughout the crediting period, but is determined only once and remain fixed throughout the crediting period, and is available already at the stage of determination	This value (0.0918 tCO_2/GJ) has been assumed as conservative value for the ER calculation. In fact, it is lower than value used in Burgas project (0.100 tCO_2/GJ). Burgas value has been calculated as weighted average value between brown coal and black and anthracite coal, considering energy consumption values (TJ) and emission factors values shown respectively in Table 2 and Table 5 of Burgas PDD
Heavy fuel oil	0.0766	Project ID: BG1000209 – Reduction of greenhouse gases by gasification of Burgas Municipality, PDD Version 08, November 2007	Data that is not monitored throughout the crediting period, but is determined only once and remain fixed throughout the crediting period, and is available already at the stage of determination	This is the value used in Burgas project and then it has been assumed as conservative value. The same value is shown in the Bulgarian National Greenhouse Gas Inventory Report (MOEW, 2011)[10]

[10] http://eea.government.bg/bg/output/unfccc/NIR-11-eng.pdf

Fuel	*Emission factor -EF $_{FF,CO2,i}$* (tCO$_2$/GJ)	Source	Comment	Conservativeness
Gasoil	0.0733	Project ID: BG1000209 – Reduction of greenhouse gases by gasification of Burgas Municipality, PDD Version 08, November 2007	Data that is not monitored throughout the crediting period, but is determined only once and remain fixed throughout the crediting period, and is available already at the stage of determination	This is the value used in Burgas project and then it has been assumed as conservative value. The same value is shown in the Bulgarian National Greenhouse Gas Inventory Report (MOEW, 2011)
Wood	0	-	-	Assumed = 0 in the emissions reduction calculation as in Burgas project
Electricity	0.344, equal to 1.238 tCO$_2$/MWh, calculated as an average between 1.233 tCO$_2$/MWh (maximum demand case) and 1.243 tCO$_2$/MWh (minimum demand case) The option “fossil fuels” has been chosen since, from the Bulgaria Energy Mix Fact Sheet - Year 2004[11], the low cost/must run sources (renewable and nuclear) are 48.1%, less than 50%; then, low cost/must run are not included in the CEF calculation and only fossil fuels are considered.	An average between the two highest baseline emission factor values for year 2006 related to the “fossil fuels Average Dispatch Data_OM_EF” (minimum and maximum demand cases) shown on table “Baseline Carbon Emission Factor of Bulgarian Electricity and Heat Power System” shown in the Ministry of Environment and Water website (see Annex 7)	Data that is not monitored throughout the crediting period, but is determined only once and remain fixed throughout the crediting period, and is available already at the stage of determination	This value is used in the calculation of emissions due to switch from electricity to natural gas. As shown in Section E.4, the conservativeness in the emissions calculation is represented by the shares of electricity in the three sectors, rather than by the value of the baseline emission factor.
LPG	0.0624	Project ID: BG1000209 – Reduction of greenhouse gases by gasification of Burgas Municipality, PDD Version 08,	Data that is not monitored throughout the crediting period, but is determined only once and remain fixed throughout	This is the value used in Burgas project and then it has been assumed as conservative value.

[11] http://ec.europa.eu/energy/energy_policy/doc/factsheets/mix/mix_bg_en.pdf

Fuel	***Emission factor* -*EF*** $_{FF,CO2,i}$ **(tCO_2/GJ)**	**Source**	**Comment**	**Conservativeness**
		November 2007	the crediting period, and is available already at the stage of determination	The same value is shown in the Bulgarian National Greenhouse Gas Inventory Report (MOEW, 2011)
Fuel	***Emission factor* - EF**$_{NG,CO2,y}$ **(tCO_2/GJ)**	**Source**	**Comment**	**Conservativeness**
Natural gas	0.0583	2006 IPCC Guidelines for National Greenhouse Gas Inventory. IPCC values at the upper 95% confidence interval have been considered , as recommended in the ACM0009 Methodology	Data that is not monitored throughout the crediting period, but is determined only once and remain fixed throughout the crediting period, and is available already at the stage of determination	This value (0.0583 tCO_2/GJ) has been assumed as conservative value for the ER calculation. In fact, it is higher than value used in Burgas project (0.0558 tCO_2/GJ)

Table D.2: Net Calorific Values

Note: As mentioned above, $NCV_{FF,i}$ (Average net calorific value of the coal or petroleum fuel that would be combusted in the absence of the project activity in the element process *i* during the year *y* in GJ per volume or mass unit) has no influence in the formula of the emission reduction calculations. For this reason, values used in Burgas project have been assumed as conservative. Similarly to what has been done for CO_2 Emission Factor, the NCV of coal has been calculated as a weighted average value among a mix of different coal types.

Fuel	***Net Calorific Value - $NCV_{FF,i}$ (GJ/ton or GJ/1,000 Sm^3)***	**Source**	**Comment**	**Conservativeness**
Coal	12.6	A weighted average value among brown coal, hard coal, lignite and coke net calorific values. This average value has been calculated considering net calorific values of the different types of coal shown on the 2006 IPCC Guidelines for National Greenhouse Gas Inventory and tons of coal provided by the National Statistic Institute (NSI). IPCC values at the lower 95% confidence interval have been considered, as recommended in the ACM0009 Methodology.	Data that is not monitored throughout the crediting period, but is determined only once and remain fixed throughout the crediting period, and is available already at the stage of determination	This value has been assumed as conservative value.
Heavy fuel oil	40	Project ID: BG1000209 – Reduction of greenhouse gases by gasification of Burgas Municipality, PDD Version 08, November 2007	Data that is not monitored throughout the crediting period, but is determined only once and remain fixed throughout the crediting period, and is available already at the stage of determination	This is the value used in Burgas project and then it has been assumed as conservative value. The same value is shown in the Bulgarian National Greenhouse Gas Inventory

Fuel	*Net Calorific Value - $NCV_{FF,i}$ (GJ/ton or GJ/1,000 Sm^3)*	Source	Comment	Conservativeness
				Report (MOEW, 2011)
Gasoil	42.3	Project ID: BG1000209 – Reduction of greenhouse gases by gasification of Burgas Municipality, PDD Version 08, November 2007	Data that is not monitored throughout the crediting period, but is determined only once and remain fixed throughout the crediting period, and is available already at the stage of determination	This is the value used in Burgas project and then it has been assumed as conservative value. The same value is shown in the Bulgarian National Greenhouse Gas Inventory Report (MOEW, 2011)
Wood	15.6	2006 IPCC Guidelines for National Greenhouse Gas Inventory	Data that is not monitored throughout the crediting period, but is determined only once and remain fixed throughout the crediting period, and is available already at the stage of determination	It is not significant. Wood is not considered in the emission reductions calculation (the emission factor of wood has been assumed = 0, then the baseline emissions are = 0)
LPG	47.6	Project ID: BG1000209 – Reduction of greenhouse gases by gasification of Burgas Municipality, PDD Version 08, November 2007	Data that is not monitored throughout the crediting period, but is determined only once and remain fixed throughout the crediting period, and is available already at the stage of determination	This is the value used in Burgas project and then it has been assumed as conservative value.
Fuel	***Net Calorific Value* - $NCV_{NG,y}$ *(GJ/1,000 Sm^3)***	**Source**	**Comment**	**Conservativeness**
Natural gas	33.1 GJ/1,000 Sm^3	IPCC 2006. This value has been calculated considering IPCC value at the lower 95% confidence interval (46.5	Data that is not monitored throughout the crediting period, but is determined only once and remain fixed throughout the crediting period, and is	This value has been assumed as conservative since it is lower than the value used in Burgas project (33.4 GJ/1,000 Sm^3)

Fuel	*Net Calorific Value - $NCV_{FF,i}$ (GJ/ton or GJ/1,000 Sm^3)*	Source	Comment	Conservativeness
		GJ/t), as recommended in the ACM0009 Methodology. A density of 0.711 kg/Sm^3 provided by Ministry of Finance, British Columbia – Conversion Factors for Fuel has been used[12]	available already at the stage of determination	Burgas value has been deduced from data on "Dynamics of energy consumptions by sources and sectors with implementation of the project, TJ" shown in Annex 2 and data on "Expected sales of natural gas, 1,000 m^3" shown in Annex 7 of Burgas PDD. A comparison with value provided by the Bulgarian National Greenhouse Gas Inventory Report (MOEW, 2011) has not been done, since, according to ACM0009 Methodology, country values can only be used for liquid fuels.

[12] http://www.sbr.gov.bc.ca/documents_library/shared_documents/Conversion_Factors.pdf

For the determination of fuel energy efficiency, values from Methodology ACM0009, Version 04.0.0 and Project ID BG1000209 (Burgas) have been used. The energy efficiency values are shown in Table D.3.

Table D.3: Energy Efficiency

Fuel	***Energy Efficiency***	**Source**	**Comment**	**Conservativeness**
Coal	0.80	Methodology ACM0009, Version 04.0.0 – Table 2: default baseline efficiency for different boilers (old coal fired boiler)	Data that is not monitored throughout the crediting period, but is determined only once and remain fixed throughout the crediting period, and is available already at the stage of determination	This value (0.80) has been assumed as conservative, since in Burgas project lower values were used (0.65 – 0.70)
Heavy fuel oil	0.85	Methodology ACM0009, Version 04.0.0 – Table 2: default baseline efficiency for different boilers (old oil fired boiler)	Data that is not monitored throughout the crediting period, but is determined only once and remain fixed throughout the crediting period, and is available already at the stage of determination	This value (0.85) has been assumed as conservative, since in Burgas project a lower value was used (0.80)
Gasoil	0.88	Project ID: BG1000209 – Reduction of greenhouse gases by gasification of Burgas Municipality, PDD Version 08, November 2007	Data that is not monitored throughout the crediting period, but is determined only once and remain fixed throughout the crediting period, and is available already at the stage of determination	This is the value used in Burgas project and then it has been assumed as conservative value. Moreover, it is higher than the value provided by ACM0009 Methodology (0.85 for old oil fired boilers)
Wood	0.65	Project ID: BG1000209 – Reduction of greenhouse gases by gasification of Burgas Municipality, PDD Version 08, November 2007	Data that is not monitored throughout the crediting period, but is determined only once and remain fixed throughout the crediting period, and is available already at the stage of determination	This is the value used in Burgas project and then it has been assumed as conservative value.
Electricity	0.98	Project ID: BG1000209 –	Data that is not monitored	This is the value used in Burgas

Fuel	***Energy Efficiency***	**Source**	**Comment**	**Conservativeness**
		Reduction of greenhouse gases by gasification of Burgas Municipality, PDD Version 08, November 2007	throughout the crediting period, but is determined only once and remain fixed throughout the crediting period, and is available already at the stage of determination	project and then it has been assumed as conservative value.
LPG	0.9	Project ID: BG1000209 – Reduction of greenhouse gases by gasification of Burgas Municipality, PDD Version 08, November 2007	Data that is not monitored throughout the crediting period, but is determined only once and remain fixed throughout the crediting period, and is available already at the stage of determination	This is the value used in Burgas project and then it has been assumed as conservative value.
Natural gas	0.9	Project ID: BG1000209 – Reduction of greenhouse gases by gasification of Burgas Municipality, PDD Version 08, November 2007	Data that is not monitored throughout the crediting period, but is determined only once and remain fixed throughout the crediting period, and is available already at the stage of determination	This is the value used in Burgas project and then it has been assumed as conservative value.

Table D.4: Global Warming Potential of methane (GWP)

Parameter	***Value***	**Source**	**Comment**
Global Warming Potential of methane (GWP)	21 tCO_{2e}/tCH_4	2006 IPCC Guidelines for National Greenhouse Gas	Data that is not monitored throughout the crediting period, but is determined only once and remain fixed throughout the crediting period, and is available already at the stage of determination

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

>>

The project emissions (PE_y) during the year y include the CO_2 emissions released during the burning of natural gas in the combustion installations in the industrial, public and administrative, and residential sectors. Project emissions are calculated based on the quantity of natural gas combusted in all element process i and respective net calorific values and CO_2 emission factors for natural gas as follows:

$$PE_y = FF_{project,y} * NCV_{NG,y} * EF_{NG,CO2,y} \quad (1)$$

where:

$$FF_{project,y} = \sum_i FF_{project,i,y} \quad (2)$$

where:

PE_y =	Project emissions during the year y in tCO_{2e}
$FF_{project,y}$ =	quantity of natural gas combusted in all element processes during the year y in m^3
$FF_{project,iy}$ =	quantity of natural gas combusted in the element process i during the year y in m^3
$NCV_{NG,y}$ =	Average net calorific value of the natural gas combusted during the year y in GJ/ m^3
$EF_{NG,CO2,y}$ =	CO_2 emission factor of the natural gas combusted in all element processes during the year y in tCO_2/GJ

As regards details on CO_2 emission factor and net calorific values, make reference to section D.1.1.1, Table D.1 and Table D.2.

The overall project emissions are the sum of the emissions of the three sectors:

$$\boldsymbol{PE_y = PE_{total\_ind,y} + PE_{total\_public,y} + PE_{total\_res,y}}$$

D.1.1.3. Relevant data necessary for determining the baseline of anthropogenic emissions of greenhouse gases by sources within the project boundary, and how such data will be collected and archived:								
ID number *(Please use numbers to ease cross-referencing to D.2.)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
B1	Final energy consumption of heavy fuel oil in the industrial sector	Energy: National Statistical Institute (NSI)	TJ	c	yearly	100%	Electronic/ paper	
B2	Final energy consumption of gasoil in the industrial sector		TJ	c	yearly	100%	Electronic/ paper	
B3	Final energy consumption of coal in the industrial sector		TJ	c	yearly	100%	Electronic/ paper	
B4	Final energy consumption of LPG in the industrial sector		TJ	c	yearly	100%	Electronic/ paper	
B5	Final energy consumption of electricity in the industrial sector		TJ	c	yearly	100%	Electronic/ paper	
B6	Final energy consumption of heavy fuel oil in the public and administrative sector	Energy: National Statistical Institute (NSI)	TJ	c	yearly	100%	Electronic/ paper	

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

B7	Final energy consumption of gasoil in the public and administrative sector		TJ	c	yearly	100%	Electronic/ paper	
B8	Final energy consumption of coal in the public and administrative sector		TJ	c	yearly	100%	Electronic/ paper	
B9	Final energy consumption of biomass in the public and administrative sector		TJ	c	yearly	100%	Electronic/ paper	
B10	Final energy consumption of LPG in the public and administrative sector		TJ	c	yearly	100%	Electronic/ paper	
B11	Final energy consumption of electricity in the public and administrative sector		TJ	c	yearly	100%	Electronic/ paper	

D.1.1.3. Relevant data necessary for determining the baseline of anthropogenic emissions of greenhouse gases by sources within the project boundary, and how such data will be collected and archived:								
B12	Final energy consumption of heavy fuel oil in the residential sector	Energy: National Statistical Institute (NSI)	TJ	c	yearly	100%	Electronic/ paper	
B13	Final energy consumption of gasoil in the residential sector		TJ	c	yearly	100%	Electronic/ paper	
B14	Final energy consumption of coal in the residential sector		TJ	c	yearly	100%	Electronic/ paper	
B15	Final energy consumption of biomass in the residential sector		TJ	c	yearly	100%	Electronic/ paper	
B16	Final energy consumption of LPG in the residential sector		TJ	*c*	yearly	100%	Electronic/ paper	
B17	Final energy consumption of electricity in the residential sector		TJ	*c*	yearly	100%	Electronic/ paper	

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

>>
The baseline emissions (BE_y) during the year y include the emissions of carbon dioxide (CO_2) released from the burning of solid and liquid fuels in the combustion installation in the industrial, public and administrative, and residential sectors, and the emissions from electricity that could be replaced by natural gas.
The emissions released from the combustion of each fossil fuel are calculated based on the quantity of used fuel that would be combusted in each element process (i.e.: boiler) in the absence of the project activity and respective net calorific value and CO_2 emission factors.

$$BE_y = \sum_i FF_{baseline,i,y} * NCV_{FF,i} * EF_{FF,CO2,I} \quad (3)$$

where:

$$FF_{baseline,i,y} = FF_{project,i,y} * NCV_{NG,y} * \varepsilon_{project,i} / NCV_{FF,i} * \varepsilon_{baseline,i,y} \quad (4)$$

where:

BE_y = baseline emissions during the year y in $t_{CO2\ e}$
$FF_{baseline,i,y}$ = quantity of coal or petroleum fuel that would be combusted in the absence of the project activity in the element process i during the year y in a volume or mass unit;
$FF_{project,i,y}$ = quantity of natural gas combusted in the element process i during the year y in m^3
$NCV_{NG,y}$ = Average net calorific value of the natural gas combusted during the year y in GJ/ m^3
$NCV_{FF,i}$ = Average net calorific value of the coal or petroleum fuel that would be combusted in the absence of the project activity in the element process i during the year y in GJ per volume or mass unit
$EF_{FF,CO2,i}$ = CO_2 emission factor of the coal or petroleum fuel type that would be combusted in the absence of the project activity in the element process i in $t_{CO2\ e}$/GJ
$\varepsilon_{project,i}$ = Energy efficiency of the element process i if fired with natural gas
$\varepsilon_{baseline,i,y}$ = Energy efficiency of the element process i if fired with coal or petroleum fuel

As regards details on CO_2 emission factor, net calorific values and energy efficiencies, make reference to section D.1.1.1, Table D.1, Table D.2 and Table D.3.

The baseline emissions are calculated by sectors as a sum of the emissions of each fuel burned in the combustion installations because of the different energy efficiency of the combustion installations and the different emission factors of the used fuels. Then, the total baseline emissions for each sector are calculated as follows:

Industrial sector: $BE_{total\_ind, y} = BE_{coal\_ind, y} + BE_{heavy\ fuel\ oil\_ind, y} + BE_{gasoil\_ind,y} + BE_{LPG\_ind, y}$

Public sector: $BE_{total\_public, y} = BE_{coal\_public, y} + BE_{heavy\ fuel\ oil\_public, y} + BE_{gasoil\_public,y} + BE_{LPG\_public, y}$

Residential sector: $BE_{total\_res, y} = BE_{coal\_res, y} + BE_{heavy\ fuel\ oil\_res, y} + BE_{gasoil\_res,y} + BE_{LPG\_res, y}$

The overall baseline emissions are the sum of the emissions of the three sectors:

$$\boldsymbol{BE_y = BE_{total\_ind, y} + BE_{total\_public, y} + BE_{total\_res, y}}$$

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

D.1.2.1. Data to be collected in order to monitor emission reductions from the project, and how these data will be archived:

ID number *(Please use numbers to ease cross-referencing to D.2.)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

Not applicable

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

>>
Not applicable

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

D.1.3.1. If applicable, please describe the data and information that will be collected in order to monitor leakage effects of the project:

ID number *(Please use numbers to ease cross-referencing to D.2.)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
L1	Natural gas leakages resulting from gas distribution network failures	Gas distribution network leakages protocol	Sm^3	e	Monthly	100%	Electronic/ paper	These leakages are not considered in the emission reductions calculation, since they are occasional leakages

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

>>

Methodology ACM0009 states that leakage may result from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary. This includes mainly fugitive CH_4 emissions and CO_2 emissions from associated fuel combustion and flaring. In this methodology, the following leakage emission sources are considered:

- Fugitive CH_4 emissions associated with fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of natural gas used in the project plant and fossil fuels used in the grid in the absence of the project activity;
- In the case LNG is used in the project plant: CO_2 emissions from fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression into a natural gas transmission or distribution system.

Thus, leakage emissions are calculated as follows:

$$LE_y = LE_{CH4,y} + LE_{LNG,CO2,y} \qquad (5)$$

where:

LE_y	=	Leakage emissions during the year *y* in t CO_2e
$LE_{CH4,y}$	=	Leakage emissions due to fugitive upstream CH_4 emissions in the year *y* in t CO_2e
$LE_{LNG,CO2,y}$	=	Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year y in t CO_2e

The proposed project activity does not include fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system.

Leakage emissions due to fugitive upstream CH_4 emissions are also considered negligible since gas distribution networks built by Rilagas do not have dismountable joints, they are fully leak tight and then the leakages from the transmission and distribution network of natural gas are negligible. Therefore, leakage emissions LE_y are considered negligible.

Monitoring of the leakages

Since leakage emissions due to fugitive upstream CH_4 emissions from the transmission and distribution network of natural gas are negligible, the monitoring of the natural gas leakages is done by reporting the volume of natural gas emitted due to unexpected accidents, for example the failure leakages after breaking of a pipeline and the scavenging prior to repairs and connecting.

In all cases of failure, an emergency act is prepared. The operators go in the place where the accident occurred and make a first estimate of the leakages, based on the diameter of the pipeline, the gas flowrate in the pipeline and the diameter of the hole. Moreover, once a month, the operators verify if possible leakages can be gathered from the readings of purchased gas and sold gas.

Data on leakages due to unexpected accidents will be registered and reported in the gas distribution network leakages protocol; moreover, being unpredictable and occasional leakages, that might never happen, they are not considered in the emission reductions calculation.

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

>>
The emission reductions by the project activity during a given year y (ER_y) is the difference between the baseline emissions (BE_y), project emission (PE_y) and leakage emissions (LE_y) as follows:

$ER_y = BE_y - PE_y - LE_y$ (10)

where:

ER_y = Emission reductions of the project activity during the year y in $tCO_{2e;}$
BE_y = Baseline emissions during the year y in $tCO_{2e;}$
PE_y = Project emissions during the year y in $tCO_{2e;}$
LE_y = Leakage emissions in the year y in $tCO_{2e;}$

Leakages are considered negligible and then they are not taken into account in the ER calculation.

As mentioned in Section D.1 a Fuel switch emission reduction factor (FSERF) will be used in the monitoring procedure. This factor is obtained by dividing the expected emissions reduction by the expected natural gas consumption. It quantifies the efficient emission reduction of the fuel switch from carbon fossil fuels to natural gas in real conditions. The FSERF measures the amount of emission reduction units by sectors which are achieved with the sale of 1,000 Sm^3 of natural gas. This factor is measured in tCO_{2e}/ 1,000 Sm^3 and it is calculated using the following formula:

$$\boldsymbol{FSERF_{y,z} = ER_{s,z} / FF_{NG,y,z}}$$

where:
$FSERF_{y,z}$ = fuel switch emission reduction factor for a respective sector z during the year y;
$ER_{s,z}$ = emission reduction for sector z during the year y in tCO_2
$FF_{NG,y,z}$ = natural gas quantity that would be combusted in a respective sector z with the project implementation during the year y in 1,000 Sm^3.

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

>>

Not Applicable (see Section F.1).

The construction and exploitation of the gas distribution network is in compliance with the current legislation of the country and the procedures of the company concerning the environmental protection.

D.2. Quality control (QC) and quality assurance (QA) procedures undertaken for data monitored:		
Data *(Indicate table and ID number)*	Uncertainty level of data (high/medium/low)	Explain QA/QC procedures planned for these data, or why such procedures are not necessary.
Table D.1.1.1 - P1 ($FF_{project, NG\_ind,y}$) Natural gas to industrial users (Sm^3)	Low	According to the General terms for the contracts for sale of natural gas by RilaGas EAD, the recording of the quantities of sales of natural gas shall be performed by flow meters included in the State Register of the means for measurement approved for use in the Republic of Bulgaria. According to the Contract on the sale of natural gas to industrial consumers, RilaGas representatives must read the sold quantities of natural gas using the readings of the commercial gas flow meters on the first day of the month following the month of supply in compliance with the Rules on the trade in natural gas. The quantity of natural gas supplied and used for the calendar month shall be established in a signed bilateral act each month. The monthly act is to be drafted on the first work day after expiry of the month by authorized representatives of the parties (RilaGas EAD and consumers). After expiry of each calendar year, authorized representatives of RilaGas EAD and consumers shall sign an annual act for natural gas consumptions on the basis of all monthly acts signed during the year.
Table D.1.1.1 - P2 ($FF_{project, NG\_public,y}$) Natural gas to public and administrative users (Sm^3)	Low	According to the General terms for the contracts for sale of natural gas by RilaGas EAD, the recording of the quantities of sales of natural gas shall be performed by flow meters included in the State Register of the means for measurement approved for use in the Republic of Bulgaria. According to the Contract on the sale of natural gas to public and administrative consumers, RilaGas representatives must read the sold quantities of natural gas using the readings of the commercial gas flow meters on the first day of the month following the month of supply in compliance with the Rules on the trade in natural gas.
Table D.1.1.1 - P3 ($FF_{project, NG\_res,y}$) Natural gas to residential users (Sm^3)	Low	According to the General terms for the contracts for sale of natural gas by RilaGas EAD, the recording of the quantities of sales of natural gas shall be performed by flow meters included in the State Register of the means for measurement approved for use in the Republic of Bulgaria. According to the Contract on the sale of natural gas to residential consumers, RilaGas representatives must read the sold quantities of natural gas using the readings of the commercial gas flow meters on the first day of the month following the month of supply in compliance with the Rules on the trade in natural gas.

D.2. Quality control (QC) and quality assurance (QA) procedures undertaken for data monitored:		
Table D.1.1.1 - P4 Natural gas purchased by Bulgargas EAD (Sm^3)	Low	Rilagas does not have control on Bulgargas gas meters. The check of the quantity of gas purchased is always carried out the first day of the month in the Bulgargas station in the presence of a representative of Bulgargas, a representative of Rilagas and a representative of the company which supplies the natural gas coming from Russia (Gazprom). Control-check of gas purchased by Bulgargas is carried out monthly by Rilagas by means of gas meters placed inside the high pressure reduction stations (AGRS / REMI stations) and inside the measurement and odorization stations placed near the Bulgargas delivery points. The quantity of natural gas purchased by Bulgargas is measured in the Rilagas meters and compared to the quantity of natural gas shown in the Bulgargas invoices. The quantity of natural gas supplied and used for the calendar month shall be established in a signed bilateral act each month. After expiry of each calendar year, authorized representatives of RilaGas EAD and Bulgargas shall sign an annual act for natural gas consumptions on the basis of all monthly acts signed during the year.
Table D.1.1.1 - P5 ($NCV_{NG,y}$) Net Calorific Value of natural gas (GJ/Sm^3)	(1)	The value of NCV is provided monthly by the Bulgargas invoices. RilaGas EAD accepts this value without measuring it; RilaGas monthly checks if this value matches the value specified in the contract with Bulgargas. In case of complaints from the end-users, Rilagas will entrust an authorized laboratory with a check of the net calorific value.

(1) Since RilaGas does not measure the NCV but checks if it matches the value of the contract with Bulgargas, the concept of uncertainty level is not applicable to the NCV.

Data on natural gas sales in the three sectors and on natural gas purchased will be monitored for the period shown in Section C.3 of the PDD.

Uncertainty levels

The uncertainty in the measurement of natural gas sales to the three sectors and of natural gas purchased by Bulgargas is shown below. The uncertainty levels depend on the types of gas meters used by Rilagas, i.e.: membrane gas meters, rotating piston gas meters, turbine gas meters. For all the three types of gas meters, uncertainty values are shown both for new gas meters and gas meters already in operation.

Membrane gas meters (residential and small public consumers)

<u>New gas meters – uncertainty level:</u> ± 3% when the gas flowrate is between the minimum value and twice the minimum;
± 2% when the gas flowrate is between twice the minimum and the maximum value

<u>Gas meters already in operation – uncertainty level:</u> ± 6% when the gas flowrate is between the minimum value and twice the minimum;
± 4% when the gas flowrate is between twice the minimum and the maximum value

Rotating piston gas meters gas meters (industrial and public consumers)

New gas meters – uncertainty level: ± 2% when the gas flowrate is between the minimum value and the 20% of the maximum value
± 1% when the gas flowrate is between the 20% of the maximum and the maximum value

Gas meters already in operation – uncertainty level: ± 4% when the gas flowrate is between the minimum value and twice the minimum
± 2% when the gas flowrate is between twice the minimum and the maximum value

Turbine gas meters (industrial and public consumers)

New gas meters – uncertainty level: ± 2% when the gas flowrate is between the minimum value and the 20% of the maximum value
± 1% when the gas flowrate is between the 20% of the maximum and the maximum value

Gas meters already in operation – uncertainty level: ± 4% when the gas flowrate is between the minimum value and twice the minimum
± 2% when the gas flowrate is between twice the minimum and the maximum value

Calibration

The calibration of the gas meters and the electronic volume conversion devices used for the measurement of natural gas delivered to the end-users and the calibration of the gas meter used for control-check of natural gas purchased by Bulgargas, are carried out according to the Order n° A-441 of 13 October 2011on calibration (art. 15)[13] published on the State Gazzette 85/2011.

The validity period of calibration of a new gas meter or a new electronic volume conversion device depends on when the equipment is installed, i.e. if it is installed in the same year when it is purchased or if it is installed one year after it was purchased.
For example, in case a gas meter is purchased and installed in the same year, the validity of calibration is two years starting from the year of the installation. Close to the expiry date of the validity of calibration, the gas meter is carried to an authorized laboratory where it is calibrated and the calibration will last for 4 years. Before carrying the gas meter to the laboratory for calibration, another gas meter is installed on the line to ensure the measure of gas flow.

[13] http://www.damtn.government.bg/images/zapovedi/zapoved_a-441_periodichnost_si.pdf (only in Bulgarian language)

In case a gas meter is installed one year after it was purchased, the calibration will be done in the year of installation and will last four years starting from the year of the installation. Close to the expiry date of the validity of calibration, the gas meter is carried to an authorized laboratory where it is calibrated and the calibration will last for 4 years.
The calibration certificates of all measurement devices are stored by RilaGas in order to keep under control the expiry dates of calibration.

The following table provides an example of the validity (shown in blu color) of calibration of a new gas meter in case it is:

1. purchased in 2012 and installed in the same year;
2. purchased in 2012 and installed in the year 2013

Equipment	***2012***	***2013***	***2014***	***2015***	***2016***	***2017***	***2018***	***2019***	***2020***	***2021***
Gas meter (purchased and installed in 2012)		*				*				*
Gas meter (purchased in 2012 and installed in 2013. Calibration is done in year 2013)					*				*	

* Close to the expiry of the validity of calibration, the gas meter is carried to a laboratory for a new calibration.

The same scheme for duration of calibration is also valid for the gas meters and electronic volume conversion devices which are installed inside the Automatic Gas Regulation Stations (AGRS) and in the Pressure Reductions Group (GRP).

Information on how records on data are kept and made available upon request
When Rilagas operators read the sold quantities of natural gas using the readings of the commercial gas flow meters, they write the reading on a paper which is then delivered to the Rilagas office of the municipality where the measurement is carried out. In case an operator loses the paper with the reading of the measurement, he goes immediately to read again the sold quantity of natural gas
Before the end of the day, the operators of Rilagas office, after checking data, enter the reading in a software called "Easy4" where data are stored and kept for a period ranging between 5 – 10 years and these data are available upon request.

For a further check the operators also insert these data in an excel file in order to make a cross-check between data in the excel file and data filed in the "Easy4" software. The cross-check is useful, for example, when operators prepare the bill for the end-users and this check also ensures the accuracy and reliability of data.
The Easy4 software can transform the measured quantities of natural gas into standard conditions by multiplying the volume read on the consumption meter counter by a fixed coefficient determined depending on the meteorological characteristics of the respective region.
Besides data on the sales of natural gas in the industrial, public and administrative sectors, also data on gas purchased by Bulgargas and data on Net Calorific Value are kept and stored following the same procedure.

Procedures to be followed if expected monitored data are unavailable
The situations where expected monitored data (i.e.: the sales of natural gas) are not available can be mainly due to the following reasons:

- in case of a malfunction of the electronic volume conversion devices: a fixed coefficient k resulting from the tables of the national metrological office is applied in order to transform the measured quantities of natural gas into standard conditions;
- in case of a malfunction of the commercial gas flow meters: if the commercial metering devices appear to be out of order (i.e.monitored data are not available or are lower/higher than expected), RilaGas will substitute them with new gas flow meters. The readings of gas consumptions will be made on both the old gas meter and on the new gas meter and a written bilateral statement will be executed between RilaGas and the end-user.

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

>>
The project owner will apply to the project activity the same procedure that is used at the moment by the project owner to monitor the other gas distribution networks. It will be responsible for overall management of the monitoring program, for collecting data, supervising and verifying the procedure of measurement and record. It will ensure that data are collected and archived appropriately and that calculations are done and archived properly.

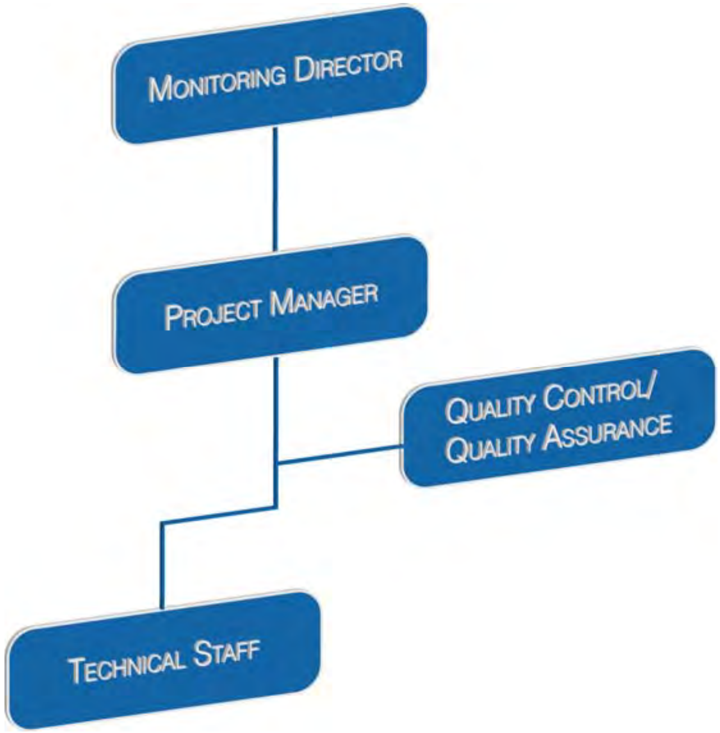
In order to obtain effective monitored data, the project owner will establish a monitoring management structure that will be composed as follows:

- a Monitoring Director that will provide the final approval of the overall monitoring program;
- a Project Manager which will be responsible for identifying the technical staff to be used for collection, monitoring, recording and archiving of data. Project Manager will take charge of supervision and it will be responsible for the check of monitoring and recording tasks (such as meters reading, sales receipt), for the check of instrument calibration, emission reductions calculation and monitoring reports preparation.
- a technical staff which will be responsible for managing the metering equipment and for recording and archiving the monitoring data. Technical staff will:
  - check gas meters, odorization instrument (Odor Handy) and their calibration;
  - collect data for buying quantities of natural gas from Bulgargas AD and will report monthly natural gas consumptions of end-users by sectors;
  - summarize the data for the total natural gas consumption by sectors in annual report;
  - prepare an annual monitoring report including the total realized carbon dioxide emission reductions in ERUs;
  - send the monitoring report to the independent verification entity;
  - organize training process regularly

- a QA/QC staff in charge of checking the accuracy of the QA/QC procedures for data monitored

All paper and electronic records will be maintained at the Rilagas office in Sofia. Data will be archived at the end of each month using electronic spread sheets. All data records will be kept for a period of 2 years following the end of the crediting period.

The organization of the project owner is shown in the following chart.



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

>>

Rilagas EAD, Mr. Ricardo Silvoni
Address: 36, Alabin Street - Sofia
Tel: +39 049 8200 405
Fax: +39 049 8200 384
e-mail: rsilvoni@acegas-aps.it

SECTION E. Estimation of greenhouse gas emission reductions

According to the JI specific approach, for the estimation of emission reductions generated by the project the approach (a) was chosen: "Assesssment of emissions in the baseline scenario and in the project scenario".

E.1. Estimated project emissions:

>>
Formulae used for the estimation of project emissions are taken from ACM0009 Methodology, Version 04.0.0 (formula n° 1 and n° 2).
Project emissions (PE_y) include CO_2 emissions from the combustion of natural gas in all element processes *i*. Project emissions are calculated based on the quantity of natural gas combusted in all element processes *i* and respective net calorific values and CO_2 emission factors for natural gas ($EF_{NG,CO2}$), as follows:

$$PE_y = FF_{project,\,y} * NCV_{NG,y} * EF_{NG,\,CO2,\,y} \quad (1)$$

with:

$$FF_{project,\,y} = \sum i\ FF_{project\ i,y} \quad (2)$$

where:

PE_y = Project emissions during the year *y* in t CO_{2e}
$FF_{project,y}$ = Quantity of natural gas combusted in all element processes during the year *y* in m³
$FF_{project,i,y}$ = Quantity of natural gas combusted in the element process *i* during the year *y* in m³
$NCV_{NG,y}$ = Average net calorific value of the natural gas combusted during the year *y* in GJ/m³
$EF_{NG,CO2,y}$ = CO_2 emission factor of the natural gas combusted in all element processes in the year y in t CO_2/GJ

Based on the expected gas consumption during the project implementation, on the net calorific values and the emission factors, the volume of GHG is calculated by sectors and years. Data for GHG emissions with project implementation for the period 2008- 2012 and 2013 - 2020 are given in the following tables:

Year	Industrial sector (tCO_{2e})	Public and administrative sector (tCO_{2e})	Residential sector (tCO_{2e})	Total (tCO_{2e})
2008	24,851	8,338	6,854	40,043
2009	54,960	17,461	19,732	92,153
2010	90,456	28,031	33,012	151,500
2011	103,120	30,793	46,604	180,518
2012	110,527	32,770	60,970	204,266
Total (tCO_{2e})	**383,914**	**117,393**	**167,172**	**668,480**

Year	Industrial sector (tCO_{2e})	Public and administrative sector (tCO_{2e})	Residential sector (tCO_{2e})	Total (tCO_{2e})
2013	112,546	33,299	73,832	219,677
2014	112,546	33,299	85,048	230,893
2015	112,546	33,299	94,568	240,413
2016	112,546	33,299	103,094	248,940
2017	112,546	33,299	109,836	255,681
2018	112,546	33,299	113,694	259,540
2019	112,546	33,299	115,682	261,527
2020	112,546	33,299	116,758	262,603
Total (tCO_{2e})	**900,365**	**266,395**	**812,513**	**1,979,274**

Total project emissions in the period 2008-2012: ***668,480 tCO_{2e}***
Total project emissions in the period 2013-2020: ***1,979,274 tCO_{2e}***

Total project emissions in the period 2008-2020: ***2,647,754 tCO_{2e}***

E.2. Estimated leakage:

>>
Formula used for the estimation of leakage emissions is taken from ACM0009 Methodology, Version 04.0.0 (formula n° 5).
Leakage may result from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary. This includes mainly fugitive CH_4 emissions and CO_2 emissions from associated fuel combustion and flaring. In this methodology, the following leakage emission sources shall be considered:

- fugitive CH_4 emissions associated with fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of natural gas used in the project plant and fossil fuels used in the grid in the absence of the project activity;
- in the case LNG is used in the project plant: CO2 emissions from fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression into a natural gas transmission or distribution system.

Thus, leakage emissions are calculated as follows:

$$LE_y = LE_{CH4,y} + LE_{LNG,CO2,y} \tag{5}$$

Where:

LE_y	=	Leakage emissions during the year *y* in t CO_2e
$LE_{CH4,y}$	=	Leakage emissions due to fugitive upstream CH_4 emissions in the year *y* in t CO_2e
$LE_{LNG,CO2,y}$	=	Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year y in t CO_2e

The proposed project activity does not include fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system.
Leakage emissions due to fugitive upstream CH_4 emissions are also considered negligible since gas distribution networks built by Rilagas do not have dismountable joints, they are fully leak tight and then the leakages from the transmission and distribution network of natural gas are negligible. Therefore, leakage emissions LE_y are considered negligible.

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

>>
Being the leakages negligible, only project emissions will be taken into account and formulae are shown below (see also Section E.1):

$$PE_y = FF_{project,y} * NCV_{NG,y} * EF_{NG,CO2,y} \quad (1)$$

with:

$$FF_{project,y} = \sum i\ FF\ project_{i,y} \quad (2)$$

where:

PE_y = Project emissions during the year y in t CO_{2e}
$FF_{project,y}$ = Quantity of natural gas combusted in all element processes during the year y in m³
$FF_{project,i,y}$ = Quantity of natural gas combusted in the element process i during the year y in m³
$NCV_{NG,y}$ = Average net calorific value of the natural gas combusted during the year y in GJ/m³
$EF_{NG,CO2,y}$ = CO_2 emission factor of the natural gas combusted in all element processes in the year y in t CO_2/GJ

E.4. Estimated baseline emissions:

>>
The baseline emissions (BE_y) during the year y include the emissions of carbon dioxide (CO_2) released from the burning of solid and liquid fuels in the combustion installation in the industrial, public and administrative, and residential sectors, and the emissions from electricity that could be replaced by natural gas.
The emissions released from the combustion of each fossil fuel are calculated based on the quantity of used fuel that would be combusted in each element process (i.e.: boiler) in the absence of the project activity and respective net calorific value and CO_2 emission factors.

$$BE_y = \sum_i FF_{baseline,i,y} * NCV_{FF,i} * EF_{FF,CO2,i} \quad (3)$$

where:

$$FF_{baseline,i,y} = FF_{project,i,y} * NCV_{NG,y} * \varepsilon_{project,i} / NCV_{FFiI} * \varepsilon_{baseline,i,y} \quad (4)$$

where:
BE_y = baseline emissions during the year y in $t_{CO2\ e}$
$FF_{baseline,i,y}$ = quantity of coal or petroleum fuel that would be combusted in the absence of the project activity in the element process i during the year y in a volume or mass unit;
$FF_{project,i,y}$ = quantity of natural gas combusted in the element process i during the year y in m^3
$NCV_{NG,y}$ = Average net calorific value of the natural gas combusted during the year y in GJ/ m^3

$NCV_{FF,i}$ = Average net calorific value of the coal or petroleum fuel that would be combusted in the absence of the project activity in the element process i during the year y in GJ per volume or mass unit
$EF_{FF,CO2,i}$ = CO_2 emission factor of the coal or petroleum fuel type that would be combusted in the absence of the project activity in the element process i in $t_{CO2\ e}$/GJ
$\varepsilon_{project,i}$ = Energy efficiency of the element process i if fired with natural gas
$\varepsilon_{baseline,i,y}$ = Energy efficiency of the element process i if fired with coal or petroleum fuel

The baseline emissions are calculated by sectors as a sum of the emissions of each fuel burned in the combustion installations because of the different energy efficiency of the combustion installations and the different emission factors of the used fuels. Then, the total baseline emissions for each sector are calculated as follows:

Industrial sector: $BE_{total\_ind,\ y} = BE_{coal\_ind,\ y} + BE_{heavy\ fuel\ oil\_ind,\ y} + BE_{gasoil\_ind,y} + BE_{LPG\_ind,\ y}$

Public sector: $BE_{total\_public,\ y} = BE_{coal\_public,\ y} + BE_{heavy\ fuel\ oil\_public,\ y} + BE_{gasoil\_public,y} + BE_{LPG\_public,\ y}$

Residential sector: $BE_{total\_res,\ y} = BE_{coal\_res,\ y} + BE_{heavy\ fuel\ oil\_res,\ y} + BE_{gasoil\_res,y} + BE_{LPG\_res,\ y}$

The overall baseline emissions are the sum of the emissions of the three sectors:
$\boldsymbol{BE_y = BE_{total\_ind,\ y} + BE_{total\_public,\ y} + BE_{total\_res,\ y}}$

The baseline emissions by sectors and years for the period 2008- 2012 and 2013-2020 are shown in the following tables (emissions due to the replacement of electricity with natural gas are excluded; these emissions are shown in the two tables at the end of this section):

Year	Industrial sector (tCO_{2e})	Public and administrative sector (tCO_{2e})	Residential sector (tCO_{2e})	Total (tCO_{2e})
2008	34,150	11,627	7,460	53,236
2009	75,525	24,348	21,477	121,350
2010	124,303	39,088	35,931	199,322
2011	141,705	42,940	50,725	235,370
2012	151,883	45,696	66,361	263,940
Total (tCO_{2e})	**527,565**	**163,699**	**181,954**	**873,219**

Year	Industrial sector (tCO_{2e})	Public and administrative sector (tCO_{2e})	Residential sector (tCO_{2e})	Total (tCO_{2e})
2013	154,657	46,434	80,361	281,452
2014	154,657	46,434	92,569	293,660
2015	154,657	46,434	102,930	304,022
2016	154,657	46,434	112,211	313,302
2017	154,657	46,434	119,549	320,640
2018	154,657	46,434	123,748	324,840
2019	154,657	46,434	125,911	327,003
2020	154,657	46,434	127,082	328,174
Total (tCO_{2e})	**1,237,259**	**371,475**	**884,359**	**2,493,093**

Total baseline emissions in the period 2008-2012: ***873,219 tCO_{2e}***
Total baseline emissions in the period 2013-2020: ***2,493,093 tCO_{2e}***

Total baseline emissions in the period 2008-2020: ***3,366,312 tCO_{2e}***

Emissions due to switch from electricity to natural gas

The approach used in the preparation of the PDD, in order to guarantee a conservative calculation of GHG emissions, was based on the following assumption relevant to switch from electricity to natural gas in the residential sector: "the most conservative choice for determining potential switch from electricity to natural gas is to consider that 100% of the energy uses (i.e. to produce hot water) is satisfied by electricity and that 100% of homes switching from electricity to natural gas will also change water boilers and kitchen stoves with natural gas fired appliances (i.e. 100% of switch from electricity to natural gas).This means to exclude 20.59% of gas sales in the residential sector from ERUs generation".
Also in the administrative/public sector, electricity was not included. The evaluation of its contribution to the total energy consumption was assumed to be equal to that of the residential sector (20.59%)
Also in the industrial sector a conservative assumption was done; the estimation of potential fuel shift from electricicty to natural gas was carried out evaluating that on the average 10 liters day water are produced by electric boilers per employee, raising its temperature by 50 degrees. The number of employees was estimated from NSI data for the west regions of Bulgaria, considering the relevant sectors (54.26% of total number of employees) and the employment rate (33.29%). This means to exclude 8.08% of gas sales in the industrial sector from ERUs generation

For this reason, the calculation of GHG emissions is very conservative, since the share of electricity is not considered in the GHG calculation and then does not contribute to ERUs (shares of electricity are respectively: 20.59% both in the residential and public sector, 8.08% in the industrial sector).

The emissions EE_y from electricity replaced by natural gas are calculated as follows:

$$EE_y = E_{R,y} * EF_{CO2,ELEC,Y}$$

where:

$$E_{R,y} = FF_{project\ i,\ y} * NCV_{NG,Y} * \varepsilon_{project,i} / \varepsilon_{baseline,I,y}$$

where:

EE_y =	Emissions from the electricity generation for year y replaced by natural gas in tCO_{2e}
$E_{R,y}$ =	Quantity of electricity replaced by natural gas in a respective sector without project implementation during the year y in MWh
$EF_{CO2,ELEC,y}$=	Carbon Emission Factor of the replaced electricity in tCO_{2e}/MWh
$FF_{project\ i,\ y}$ =	quantity of natural gas combusted in the element process i during the year y in m^3
$NCV_{NG,Y}$ =	Average net calorific value of the natural gas combusted during the year y in GJ/ m^3
$\varepsilon_{project,i}$ =	Energy efficiency of the element process i if fired with natural gas
$\varepsilon_{baseline,i,y}$ =	Energy efficiency of the element process i if fired with electricity

The emissions due to the ***replacement of electricity*** with natural gas by sectors and years for the period 2008- 2012 and 2013-2020 are shown below:

Year	Industrial sector (tCO_{2e})	Public and administrative sector (tCO_{2e})	Residential sector (tCO_{2e})	Total (tCO_{2e})
2008	11,830	11,708	9,624	33,162
2009	26,163	24,518	27,708	78,390
2010	43,061	39,361	46,355	128,777
2011	49,090	43,239	65,442	157,771
2012	52,615	46,015	85,613	184,244
Total (tCO_{2e})	**182,760**	**164,843**	**234,741**	**582,343**

Year	Industrial sector (tCO_{2e})	Public and administrative sector (tCO_{2e})	Residential sector (tCO_{2e})	Total (tCO_{2e})
2013	53,577	46,759	103,674	204,009
2014	53,577	46,759	119,424	219,759
2015	53,577	46,759	132,791	233,126
2016	53,577	46,759	144,764	245,099
2017	53,577	46,759	154,231	254,566
2018	53,577	46,759	159,648	259,984
2019	53,577	46,759	162,439	262,775
2020	53,577	46,759	163,950	264,285
Total (tCO_{2e})	**428,612**	**374,070**	**1,140,922**	**1,943,603**

Total emissions in the period 2008-2012: **5*82,343 tCO_{2e}***
Total emissions in the period 2013-2020: 1***,943,603 tCO_{2e}***

Total emissions in the period 2008-2020: ***2,525,946 tCO_{2e}***

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

>>
The emission reductions by the project activity during a given year y (ER_y) are calculated as difference between the baseline emissions (BE_y), project emission (PE_y) and leakage emissions (LE_y) as follows:

$$ER_y = BE_y - PE_y - LE_y \quad (10)$$

where:

ER_y = Emission reductions of the project activity during the year y in $tCO_{2e;}$
BE_y = Baseline emissions during the year y in $tCO_{2e;}$
PE_y = Project emissions during the year y in $tCO_{2e;}$
LE_y = Leakage emissions in the year y in $tCO_{2e;}$

Leakages are considered negligible and they are not taken into account in the ER calculation; thus, formula used for the emission reductions calculation is:
$ER_y = BE_y - PE_y$

The results are shown in Section E.6.

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

>>

The estimated emission reductions ER_y for the period 2008-2012 and 2013-2020 are shown in the following tables (emissions due to the replacement of electricity with natural gas are excluded):

Year	Estimated project emissions (tCO_{2e})	Estimated leakages (tCO_{2e})	Estimated baseline emissions (tCO_{2e})	Estimated emission reductions (tCO_{2e})
2008	40,043	0	53,236	13,194
2009	92,153	0	121,350	29,197
2010	151,500	0	199,322	47,822
2011	180,518	0	235,370	54,852
2012	204,266	0	263,940	59,674
Total (tCO_{2e})	**668,480**	**0**	**873,219**	**204,739**

Year	Estimated project emissions (tCO_{2e})	Estimated leakages (tCO_{2e})	Estimated baseline emissions (tCO_{2e})	Estimated emission reductions (tCO_{2e})
2013	219,677	0	281,452	61,775
2014	230,893	0	293,660	62,767
2015	240,413	0	304,022	63,609
2016	248,940	0	313,302	64,363
2017	255,681	0	320,640	64,959
2018	259,540	0	324,840	65,300
2019	261,527	0	327,003	65,476
2020	262,603	0	328,174	65,571
Total (tCO_{2e})	**1,979,274**	**0**	**2,493,093**	**513,820**

A reduction of ***204,739*** tCO_{2e} will be achieved with the project implementation during the period 2008-2012.
A reduction of ***513,820*** tCO_{2e} will be achieved with the project implementation during the period 2013-2020.
A reduction of ***718,559*** tCO_{2e} will be achieved with the project implementation during the period 2008-2020.

SECTION F. Environmental impacts

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

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The license for the distribution of natural gas for the gasification of Zapad region and the license for gas supply to the end-users were awarded to Rilagas by the State Regulatory Energy and Water Commission on 03/10/2006.

Since the licenses were granted by the Bulgarian Government and given the limited project-related environmental and social impacts, Rilagas was not required to conduct an Environmental Impact Assessment (EIA).

According to the local regulations, Rilagas has the duty to verify whether the project can affect any protected areas (e.g. Natura 2000 sites). Should this be the case, the local law requires that a specific EIA has to be carried out and submitted to relevant Authority for obtaining construction permit.

Rilagas is requested to submit the design documentation to the relevant authorities (including the Ministry of Environment). If a protected area is potentially affected by the Project, Rilagas is notified and requested to carry on the related procedure.

The presence of protected areas, Natura 2000 sites, water bodies and other potentially sensitive sites it has been taken into consideration under the normal procedures required by the local legislation since the preliminary design stages of the Project.

Should the preliminary site assessment and the preliminary gas pipe network design identify the presence of sensitive areas, the decision to require or not a national environmental impact assessment procedure is demanded to the competent authority (Ministry of Environment or its regional authority). The competent authority notifies Rilagas if such EIA is required for the proposed investment or not.

Rilagas will follow the procedures required by Bulgarian regulation when sensitive areas are identified. These procedures include the preparation of environmental reports/assessments in case any potential sensitive area (Natura 2000 sites, protected zones, etc.) is identified during project planning. In particular, the procedure requires Rilagas to send a request to the competent authority that defines if and to what extent any ecological report or EIA procedure is necessary. Should it be the case, the required process is conducted by an independent expert, registered at the Ministry of Environment and Water (MOEW).

Specific technical criteria and pipeline network routing will be used during the project design stage to minimize/avoid the crossing of forest, environmental protected areas, and rivers. Should the project intercept an area considered sensitive from an environmental point of view, an independent registered consultant is nominated to certify the impact entity and a specific procedure to gain the authorization from the Ministry of Forest is activated. At the end of the construction activities, project areas will be returned to the original environmental conditions through restorations activities.

An environment and emission study in Zapad region was prepared by RilaGas (see Annex 6). This study shows how the implementation of the Project would bring strong environmental benefits to the atmospheric conditions of the Zapad region, in terms both of improvement of air quality and reduction of GHG emissions.

This study also shows the change of the emissions after the gasification, in particular highlighting that the reduction of the harmful emissions is realized in the gasification process through the construction of the gas distribution network and the replacement of the used fuels with natural gas.

The reduction of the harmful influence on the environment is achieved as a result of the use of natural gas and the reduction of the total quantity of energy used due to the increase of the energy efficiency of the burner installations.

The emissions will be reduced thanks to the lower emission factor of natural gas in respect to the fuels it will substitute and thanks to the higher efficiency of new gas fired systems replacing older liquid and solid fuel systems.

This study shows that replacing solid and liquid fossil fuels with natural gas results in a considerable reduction of dust and sulphur oxides. In particular, due to the high content of solid dust particles in Bulgaria, the study points out that the reduction of dust emissions is very important in the assessment of the impact of gasification on the environment.
The environment and emission study states that the replacement of solid and liquid fossil fuels and electricity with natural gas will reduce the emissions of harmful substances in Bulgaria; it was estimated that the gasification of Zapad region will achieve a greenhouse gases emissions reduction by more than 300,000 t/y. This value does not take into account the reductions from replacement of electricity and the losses during transportation and distribution.

The conclusions of the study indicate that the project construction and operation will not have a negative impact on environment and health of people. Moreover, the gasification of sites in the three consumer sectors will improve the working conditions and the living comfort of people and will have a long positive impact on health.

Given the characteristics of the project activities, no transboundary impacts are envisaged.

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

>>

Rilagas observes and complies with the requirements of all regulations on environment protection during the implementation of the project for the realization of the gas distribution network on the territory of Zapad region.
As shown in Section F.1 the gasification of Zapad region has no negative impact on the environment. As a result of the project implementation, the improvement of the air quality in the region will be achieved.

SECTION G. Stakeholders' comments

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

>>

During the construction of gas transportation and distribution networks consultation events took place, as a part of the design phase of the project, involving Municipality and Local Community Offices and State Authorities.
Some events to inform stakeholders about the program were organized, such as:

- **31 March 2011: Presentation of AcegasAps and Rilagas; the commitment of AcegasAps for the gasification of the Zapad region, the initiatives implemented and future projects.**
  This event was held on March 2011 in Grand Hotel Sofia and the main aim was to present Acegas Aps and RilaGas, the activities of RilaGas in Bulgaria, the updating of the current situation and the planned future projects.
  The event was covered by representatives of local and state administration as well as national media. This event was of national importance and it was published on several local newspapers and broadcast on local radios and televisions.

  Cesare Pillon, managing director of AcegasAps and Sergio Pantano, managing director of Rilagas explained that AcegasAps owns Bulgarian construction company RilaGas, which has obtained licenses for distribution and supply of natural gas to the users in the Zapad region for 35 years.
  They highlighted that RilaGas is currently building a gas distribution network in western Bulgaria (870 km of network, worth 130 million euro) in seven Municipalities, Blagoevgrad, Vratza, Dupnitza Ihtiman, Pernik, Radomir and Sandanski and that this network shall be completed by 2020.
  This project will enable people to heat and cool their homes, to use natural gas for cooking and for hot water production. They pointed out the twofold advantage of natural gas: it enables a considerable reduction of greenhouse gases emissions and its cost is lower if compared with the other fuels. For example, the heating with natural gas is 42% cheaper than that provided by electricity, 45% cheaper than that provided by butane-propane and 53% cheaper than that provided by diesel.
  RilaGas estimated that the average cost to heat an apartment of 75 m^2 is equal to about 120 lev/month during winter season and 40 lev/month in summer, much less than the most common types of fuels.
  This project is “the first of its kind” since, even if there are four gasification projects already registered as JI in Bulgaria, the proposed gas distribution network is innovative thanks to the following reasons:
  - it is the only network that supplies natural gas to the end-users at low pressure (0.5 bar) with higher safety standard;
  - the addition of an odorant to gas to ensure characteristic odor of natural gas so that the presence of gas in air in concentration below the lower explosive limit is readily detectable in case of gas leakage.

  They explained that on 31 March 2011 Rilagas invested 46 million lev in the construction of 134 km of gas network in the region and that in the year 2010 RilaGas started the works on the gas distribution network in the Municipalities of Dupnitza, Sandanski and Radomir. Moreover, during 2010 the gas distribution network of Blagoevgrad was put into operation, whereas in June 2011and September 2011was planned that the gas distribution network of Pernik and Vratza, and Dupnitza and Sandanski will be put into operation respectively.

As further investment, they pointed out that Rilagas will invest 55.8 million euro over the next three years to build a total of 370 km of gas network and connections, with an average of about 120 km per year.
Finally, they highlighted that, to use the natural gas in their houses, families should arrange new installations; costs arising from new equipment may depend mainly on the type of heating system chosen, on the surface of the house and on upgrading or complete change of the current installation.
The costs range between 2,000 and 5,000 lev for a complete change of the installation, whereas the connection fee is paid only once. This fee is 398 lev for residential users, 1,488 lev for public users and 3,145 lev for industrial users.
To help the end-users to face the costs for the new installations, RilaGas in cooperation with the banks, will propose a loan of 5-10 years at a very affordable rate and without warranty by the users.
At the same time, AcegasAps and RilaGas managing directors pointed out that there is a lot of bureaucracy involved in each step of their investments in Bulgaria and in the Zapad region and that is time-consuming and inefficient for the companies.
They highlighted the rigidity of burocracy in the issuances of permits, laws and operational inadequacy, fundamental obstacles to the development of the gas supply market in Bulgaria.
Moreover, they also complained about the terms included in the tender are continuously changed and that there is a shortage of skilled technicians and workmen in the gas sector.
Nevertheless, Mr. Pantano expressed his hope that this situation can be changed, adding that currently in the company are working 30 Bulgarian technical specialists and engineers, whose number should increase to 60. The activities of the company will create approximately 600 new jobs in the Zapad region.

13-14 March 2012: Business breakfast for reporters organized for the start-up of the first the first lot of Pernik and Vratza network

These events were held on March 2012 and the main aim was to present the realization of the first lot of Pernik and Vratza network.
The events were covered by representatives of local, regional and national media; they were of national importance and were published on local newspapers and broadcast on local radios and televisions.
RilaGas highlighted that ecological and economical natural gas is already available to residents of the town and pointed out the twofold advantage of natural gas: it enables a considerable reduction of greenhouse gases emissions and its cost is lower if compared with the other fuels. For example, the heating with natural gas is 42% cheaper than that provided by electricity, 45% cheaper than that provided by butane-propane and 53% cheaper than that provided by diesel.
RilaGas completed and put into operation the first stage of the distribution network of Pernik and Vratza thus making natural gas available to thousands of homes and businesses in the towns. This service will enable residents to significantly reduce bills for heating and cooking.
Rilagas prepared a team of experts, familiar with the features and advantages of the service provided by the company and procedures for inclusion in the network, that will visit the owners of households in the two towns. They will be provided with identification cards, and for greater certainty, their names will be reported to local authorities.
The first three households, within the municipality "East", connected to the transmission network of the Rilagas are already users of the service; the network also include an industrial user.
Positive comments were made by Municipality Offices and State Authorities.

Annex 1

CONTACT INFORMATION ON PROJECT PARTICIPANTS

Organisation:	Rilagas EAD
Street/P.O.Box:	36, Alabin Street
Building:	
City:	Sofia
State/Region:	Sofia
Postal code:	1000
Country:	Bulgaria
Phone:	+39 049 8200 405
Fax:	+39 049 8200 384
E-mail:	rsilvoni@acegas-aps.it
URL:	www.rilagas.bg
Represented by:	Mr. Ricardo Silvoni
Title:	
Salutation:	Mr.
Last name:	Silvoni
Middle name:	
First name:	Ricardo
Department:	
Phone (direct):	+39 049 8200 405
Fax (direct):	+39 049 8200 384
Mobile:	+39 388 9477 579
Personal e-mail:	rsilvoni@acegas-aps.it

Organisation:	SIL s.r.l.
Street/P.O.Box:	Corso Stati Uniti 5/A
Building:	
City:	Padova
State/Region:	
Postal code:	35127
Country:	Italy
Phone:	+39 049 8200 405
Fax:	+39 049 8200 384
E-mail:	rsilvoni@acegas-aps.it
URL:	www.sil-lining.com
Represented by:	Mr. Ricardo Silvoni
Title:	
Salutation:	Mr.
Last name:	Silvoni
Middle name:	
First name:	Ricardo
Department:	
Phone (direct):	+39 049 8200 405
Fax (direct):	+39 049 8200 384
Mobile:	+39 388 9477 579
Personal e-mail:	rsilvoni@acegas-aps.it

Annex 2

BASELINE INFORMATION

This annex includes the estimation of share of energy fuels and tables showing the calculation of baseline emissions for the three sectors industrial, public and administrative, and residential. This annex includes also tables showing emissions due to switch from electricity to natural gas.

1. *Estimation of the share of energy sources*

The share between the energy sources used in the baseline scenario was calculated starting from the following sources:

- the attachments to the Tender for gasification of the Zapad Region (attached to the PDD);
- additional analyses internally made by Rilagas;
- information from the National Statistical Institute (NSI).

In particular, the following ones were used:

- Attachment 2 provides the numbers of inhabitants and settlements in the Zapad Region;
- Attachment 3 provides an analysis of the residential units in the area;
- Attachment 4 provides an evaluation of energy needs for heating, domestic hot water preparation and cooking for residential units, and an indication of potential gas consumption;
- Attachment 9 indicates the consumption of fuels in the public and residential sector,
- Attachment 10 estimates the potential demand of natural gas for each sector in the area.

Rilagas conducted its own analyses to better assess the potential, and in particular evaluated fuel consumption in the industrial sector for subjects interested to connection to the gas network for the Municipalities of Blagoevgrad, Pernik, Vratza, Dupnitsa, Radomir, Sandanski, Ihtiman, Roman, Simitli, Kostenets, Dolna Banya, Sapareva Banya, Etropole, Boychinovtsi, Strumiani, Boboshevo, Nevestino, Kocherinovo, Krivodol, Gorna Malina, Bobov dol and Kresna from which the share of currently used fuels was calculated. No analyses were performed on electricity uses for heating purposes, which could be switched to natural gas. Such studies are commonly difficult to be performed, there is no similar study done in Bulgaria not even at national level, and the share of electricity for heating purposes, considering high electricity cost, is low. Thus, in 2006 this component was neglected to the analyses. At that time such simplification was conservative, since the emission factor of the grid per kWh used for heating purposes is much higher that of any other fuel. Currently, however, emissions resulting from reduction of electric energy end-uses have been included in the Bulgarian National Allocation Plan 2008-2012, so that the initial approach has to be modified since it would lead to indirect double counting of emission reductions. The approach was thus modified assessing the maximum possible share in electricity use for heating purposes, in order to achieve a conservative estimation of emission reductions suitable for ERUs generation. In the following, the analysis is carried out sector by sector.

1.1 *Residential sector*

The share of possible uses of natural gas in the twenty two municipalities was done using Attachment 9, Attachment 3 and Attachment 4 of the Tender. Attachment 9 was used to evaluate the share of fuels currently used in the residential and in the commercial sector, after converting data in Gigajoule (GJ).
The share of fuels is reported in the following table. In this sector heavy fuel oil and natural gas are not used.

Share of fuels in the residential sector

Coal	15.93%
Firewood	81.82%
Gasoil	0.18%
LPG	2.07%

Considering the very low price of firewood and coal in respect to natural gas, both in terms of fuel cost and of the investment needed for connection to the gas network and for installing a gas fired heating system, it was assumed that people shifting to natural gas do it for comfort reasons. Thus, residents that shift to natural gas are those which would otherwise have shifted to gasoil or LPG systems, the amounts of which are evaluated in proportion to the current fuel use. The share of fuels substituted by natural gas are thus as in the following table.

Share of fuels in the residential sector

Gasoil	8.09%
LPG	91.91%

These percentages are assumed as constant along the year and, multiplied by the volumes of gas that Rilagas plans to sell year by year, would have provided the value of $FF_{project\ i,\ y}$ of emission reductions that would have been generated at the time when the investment decision was taken.
Considering that the National allocation plan excludes at present electricity from generating ERUs, possible shifts from electricity to gas would induce to indirect double counting. Thus a maximum value for switch from electricity to natural gas was guessed. This evaluation was done using the data included in Attachment 4 of the Tender. These data show that the evaluation of potential demand was based on the following parameters:

- space heating consumption is estimated at 277.77 kWh/m^2 y,
- domestic hot water production is estimated at 37.95 kWh/m^2 y,
- cooking consumption is estimated at 637.90 kWh/m^2 occupant.

The share of these three components in the Zapad region was calculated according to the information on population and heated surfaces provided in Attachment 4. From these data, it resulted that 79.41% of the heat is used for space heating, 10.85% for domestic hot water production (DHW) and 9.74% for cooking. In areas without availability of gas, most of cooking appliances and water boilers are either electric or use LPG. In absence of a reliable demand-side study on energy uses, the most conservative choice for determining potential switch from electricity to natural gas is to consider that 100% of these uses is satisfied by electricity and that 100% of homes switching to natural gas will also change water boilers and kitchen stoves with natural gas fired appliances. This means to exclude 20.59% of gas sales in the sector from ERUs generation. The final share of energy in the baseline is obtained multiplying the previous one, not considering electricity, by 79.41%, and considering the remaining 20.59% as a shift from electricity to natural gas. The following table provides these percentages, allowing the determination of $FF_{project\ gasoil\_res,\ y}$, $FF_{project\ LPG\_res\ ,\ y}$, and $FF_{project\ electricity\_res,\ y}$ needed to calculate baseline emissions according to the chosen Methodology.

Share of energy sources in the residential sector

Gasoil	6.42%
LPG	72.99%
Electricity	20.59%

1.2 Public and administrative sector

The share of fuels used in the public and administrative sector was also calculated starting from Attachment 9 of the Tender, after converting the quantities in Gigajoule. There is the will by public administrations to shift rapidly to natural gas once it will be available, for environmental and economic reasons, in all buildings where it will be possible. In Pernik, a large amount of gas consumption in the sector is already satisfied by natural gas via Bulgargas; this amount was excluded from the calculation since it would not be interested by the project. The remaining buildings use coal, heavy fuel oil and gasoil. The resulting breakdown is shown in the following table.

Share of energy use from fuels in the public and administrative sector (excl. natural gas)

Coal	16.90%
Heavy fuel oil	24.99%
gasoil	58.11%

Also in this sector, electricity was not included. The evaluation of its contribution to the total energy consumption was assumed to be equal to that of the residential sector. In this way, fuels only contribute to 79.41% of the total energy consumption, and the resulting breakdown of energy uses becomes as indicated in the following table.

Share of energy use switchable to natural gas in the public and administrative sector

Coal	13.41%
Heavy fuel oil	19.85%
Gasoil	46.15%
electricity	20.59%

1.3 Industrial and productive sector

Rilagas made an analysisis of potential customers interested to shift to natural gas in the industrial and productive sector, evaluating the potential sales amounts by single factories and plants from their current fuel use. The analysis, made in terms of potential sales of cubic meters of natural gas, also evaluated the type of fuel, excluding electricicity. The potential also includes some gasoline stations which will start selling natural gas to cars and trucks, as indicated in the following table.

Share of energy use from fuels among the potential interested customers

coal	2.42%
Heavy fuel oil	73.52%
gasoil (*)	23.65%
LPG	0.41%

(*) included gasoil for vehicles

The estimation of potential fuel shift from electricicty to natural gas was done evaluating that on the average 10 liters day water are produced by electric boilers per employee, raising its temperature by 50 degrees. The number of employees was estimated from NSI data for the west regions of Bulgaria, considering the relevant sectors (54.26% of total number of employees) and the employment rate (33.29%). As a result, the share of shift to natural gas in the sector is evaluated as in the following table.

Share of energy use switchable to natural gas in the industry

coal	2.23%
Heavy fuel oil	67.57%
gasoil (*)	21.74%
LPG	0.38%
electricity	8.08%

(*) included gasoil for vehicles

2. *Calculation of baseline emissions*

For each sector, two tables are shown; one table shows the calculation of $FF_{baseline,i,y}$ while the other table shows the calculation of BE_y according to the ACM0009 Methodology, version 04.0.0..

$$BE_y = \sum_i FF_{baseline,i,y} * NCV_{FF,i} * EF_{FF,CO2,i} \quad (3)$$

with:

$$FF_{baseline,i,y} = FF_{project,i,y} * NCV_{NG,y} * \varepsilon_{project,i} / NCV_{FF,i} * \varepsilon_{baseline,i,y} \quad (4)$$

where:

BE_y =	Baseline emissions during the year y in tCO_{2e}
$FF_{baseline,i,y}$ =	Quantity of coal or petroleum fuel that would be combusted in the absence of the project activity in the element process i during the year y in a volume or mass unit
$FF_{project,i,y}$ =	Quantity of natural gas combusted in the element process i during the year y in m^3
$NCV_{NG,y}$ =	Average net calorific value of the natural gas combusted during the year y in GJ/ m^3
$NCV_{FF,i}$ =	Average net calorific value of the coal or petroleum fuel that would be combusted in the absence of the project activity in the element process i during the year y in GJ per volume or mass unit
$EF_{FF,CO2,i}$ =	CO_2 emission factor of the coal or petroleum fuel type that would be combusted in the absence of the project activity in the element process i in $t_{CO2\ e}$/GJ
$\varepsilon_{project,i}$ =	Energy efficiency of the element process i if fired with natural gas
$\varepsilon_{baseline,i,y}$ =	Energy efficiency of the element process i if fired with coal or petroleum fuel

$FF_{baseline,i,y}$ - Industrial sector

Year	*FF* $_{baseline\ i,\ y}$ (t)		FF $_{project\ i,\ y}$ (Sm³/y)						NCV $_{NG,Y}$ (GJ/Sm³)	ε $_{project,\ i}$ -	NCV $_{ff,\ i}$ (GJ/t)						ε $_{baseline,\ i,y}$ -					
			Coal	HFO	Gasoil	Wood	LPG	Electricity	Natural gas	Natural gas	Coal	HFO	Gasoil	Wood	LPG	Electricity	Coal	HFO	Gasoil	Wood	LPG	Electricity
2008	*FF baseline* $_{coal\ ind,\ y}$	923	312,425								12.6						0.8					
	FF baseline $_{HFO\ ind,\ y}$	8,294		9,466,618								40						0.85				
	FF baseline $_{gasoil\ ind,\ y}$	2,438			3,045,794								42.3						0.88			
	FF baseline $_{wood\ ind,\ y}$	0				0			0.0331	0.9				15.6						0.65		
	FF baseline $_{LPG\ ind,\ y}$	37					53,238								47.6						0.9	
	FF baseline $_{electricity\_ind,\ y}$	*excluded from ER count*																				
2009	*FF baseline* $_{coal\ ind,\ y}$	2,042	690,949								12.6						0.8					
	FF baseline $_{HFO\ ind,\ y}$	18,344		20,936,079								40						0.85				
	FF baseline $_{gasoil\ ind,\ y}$	5,391			6,735,983								42.3						0.88			
	FF baseline $_{wood\ ind,\ y}$	0				0			0.0331	0.9				15.6						0.65		
	FF baseline $_{LPG\ ind,\ y}$	82					117,740								47.6						0.9	
	FF baseline $_{electricity\_ind,\ y}$	*excluded from ER count*																				
2010	*FF baseline* $_{coal\ ind,\ y}$	3,361	1,137,200								12.6						0.8					
	FF baseline $_{HFO\ ind,\ y}$	30,191		34,457,675								40						0.85				
	FF baseline $_{gasoil\ ind,\ y}$	8,872			11,086,427				0.0331	0.9			42.3						0.88			
	FF baseline $_{wood\ ind,\ y}$	0				0								15.6						0.65		
	FF baseline $_{LPG\ ind,\ y}$	135					193,783								47.6						0.9	

Year	$FF_{baseline\ i,y}$ (t)		$FF_{project\ i,y}$ (Sm^3/y)						$NCV_{NG,Y}$ (GJ/Sm^3)	$\varepsilon_{project,\ i}$ -	$NCV_{ff,\ i}$ (GJ/t)						$\varepsilon_{baseline,\ i,y}$ -					
			Coal	HFO	Gasoil	Wood	LPG	Electricity	Natural gas	Natural gas	Coal	HFO	Gasoil	Wood	LPG	Electricity	Coal	HFO	Gasoil	Wood	LPG	Electricity
	FF baseline $_{electricity\_ind,\ y}$	***excluded from ER count***																				
2011	*FF baseline* $_{coal\_ind,\ y}$	3,831	1,296,410						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_ind,\ y}$	34,418		39,281,801								40						0.85				
	FF baseline $_{gasoil\_ind,\ y}$	10,115			12,638,543								42.3						0.88			
	FF baseline $_{wood\_ind,\ y}$	0				0								15.6						0.65		
	FF baseline $_{LPG\_ind,\ y}$	154					220,913								47.6						0.9	
	FF baseline $_{electricity\_ind,\ y}$	***excluded from ER count***																				
2012	*FF baseline* $_{coal\_ind,\ y}$	4,107	1,389,520						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_ind,\ y}$	36,890		42,103,084								40						0.85				
	FF baseline $_{gasoil\_ind,\ y}$	10,841			13,546,264								42.3						0.88			
	FF baseline $_{wood\_ind,\ y}$	0				0								15.6						0.65		
	FF baseline $_{LPG\_ind,\ y}$	165					236,779								47.6						0.9	
	FF baseline $_{electricity\_ind,\ y}$	***excluded from ER count***																				
2013	*FF baseline* $_{coal\_ind,\ y}$	4,182	1,414,904						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_ind,\ y}$	37,564		42,872,232								40						0.85				
	FF baseline $_{gasoil\_ind,\ y}$	11,039			13,793,730								42.3						0.88			
	FF baseline $_{wood\_ind,\ y}$	0				0								15.6						0.65		

Year	$FF_{baseline\ i,y}$		$FF_{project\ i,y}$						$NCV_{NG,Y}$	$\varepsilon_{project,\ i}$	$NCV_{ff,\ i}$						$\varepsilon_{baseline,\ i,y}$					
	(t)		(Sm^3/y)						(GJ/Sm^3)	-	(GJ/t)						-					
			Coal	HFO	Gasoil	Wood	LPG	Electricity	Natural gas	Natural gas	Coal	HFO	Gasoil	Wood	LPG	Electricity	Coal	HFO	Gasoil	Wood	LPG	Electricity
	FF baseline $_{LPG\_ind,y}$	168					241,105								47.6						0.9	
	FF baseline $_{electricity\_ind,y}$	***excluded from ER count***																				
2014	***FF baseline*** $_{coal\_ind,y}$	4,182	1,414,904						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_ind,y}$	37,564		42,872,232								40						0.85				
	FF baseline $_{gasoil\_ind,y}$	11,039			13,793,730								42.3						0.88			
	FF baseline $_{wood\_ind,y}$	0				0								15.6						0.65		
	FF baseline $_{LPG\_ind,y}$	168					241,105								47.6						0.9	
	FF baseline $_{electricity\_ind,y}$	***excluded from ER count***																				
2015	***FF baseline*** $_{coal\_ind,y}$	4,182	1,414,904						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_ind,y}$	37,564		42,872,232								40						0.85				
	FF baseline $_{gasoil\_ind,y}$	11,039			13,793,730								42.3						0.88			
	FF baseline $_{wood\_ind,y}$	0				0								15.6						0.65		
	FF baseline $_{LPG\_ind,y}$	168					241,105								47.6						0.9	
	FF baseline $_{electricity\_ind,y}$	***excluded from ER count***																				
2016	***FF baseline*** $_{coal\_ind,y}$	4,182	1,414,904						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_ind,y}$	37,564		42,872,232								40						0.85				
	FF baseline $_{gasoil\_ind,y}$	11,039			13,793,730								42.3						0.88			

Year	$FF_{baseline\ i,y}$		$FF_{project\ i,y}$						$NCV_{NG,Y}$	$\varepsilon_{project,i}$	$NCV_{ff,i}$						$\varepsilon_{baseline,i,y}$					
	(t)		(Sm^3/y)						(GJ/Sm^3)	-	(GJ/t)						-					
			Coal	HFO	Gasoil	Wood	LPG	Electricity	Natural gas	Natural gas	Coal	HFO	Gasoil	Wood	LPG	Electricity	Coal	HFO	Gasoil	Wood	LPG	Electricity
	FF baseline $_{wood\ ind,y}$	0				0								15.6						0.65		
	FF baseline $_{LPG\ ind,y}$	168					241,105								47.6						0.9	
	FF baseline $_{electricity\_ind,y}$	***excluded from ER count***																				
2017	**FF baseline** $_{coal\ ind,y}$	4,182	1,414,904								12.6						0.8					
	FF baseline $_{HFO\ ind,y}$	37,564		42,872,232								40						0.85				
	FF baseline $_{gasoil\ ind,y}$	11,039			13,793,730								42.3						0.88			
	FF baseline $_{wood\ ind,y}$	0				0			0.0331	0.9				15.6						0.65		
	FF baseline $_{LPG\ ind,y}$	168					241,105								47.6						0.9	
	FF baseline $_{electricity\_ind,y}$	***excluded from ER count***																				
2018	**FF baseline** $_{coal\ ind,y}$	4,182	1,414,904								12.6						0.8					
	FF baseline $_{HFO\ ind,y}$	37,564		42,872,232								40						0.85				
	FF baseline $_{gasoil\ ind,y}$	11,039			13,793,730								42.3						0.88			
	FF baseline $_{wood\ ind,y}$	0				0			0.0331	0.9				15.6						0.65		
	FF baseline $_{LPG\ ind,y}$	168					241,105								47.6						0.9	
	FF baseline $_{electricity\_ind,y}$	***excluded from ER count***																				
2019	**FF baseline** $_{coal\ ind,y}$	4,182	1,414,904						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\ ind,y}$	37,564		42,872,232								40						0.85				

Year	$FF_{baseline\ i,\ y}$		$FF_{project\ i,\ y}$						$NCV_{NG,Y}$	$\varepsilon_{project,\ i}$	$NCV_{ff,\ i}$						$\varepsilon_{baseline,\ i,y}$					
	(t)		(Sm^3/y)						(GJ/Sm^3)	-	(GJ/t)						-					
			Coal	HFO	Gasoil	Wood	LPG	Electricity	Natural gas	Natural gas	Coal	HFO	Gasoil	Wood	LPG	Electricity	Coal	HFO	Gasoil	Wood	LPG	Electricity
	FF baseline $_{gasoil\ ind,\ y}$	11,039			13,793,730								42.3						0.88			
	FF baseline $_{wood\ ind,\ y}$	0				0								15.6						0.65		
	FF baseline $_{LPG\ ind,\ y}$	168					241,105								47.6						0.9	
	FF baseline $_{electricity\_ind,\ y}$	***excluded from ER count***																				
	FF baseline $_{coal\ ind,\ y}$	4,182	1,414,904								12.6						0.8					
	FF baseline $_{HFO\ ind,\ y}$	37,564		42,872,232								40						0.85				
	FF baseline $_{gasoil\ ind,\ y}$	11,039			13,793,730								42.3						0.88			
2020	***FF baseline*** $_{wood\ ind,\ y}$	0				0			0.0331	0.9				15.6						0.65		
	FF baseline $_{LPG\ ind,\ y}$	168					241,105								47.6						0.9	
	FF baseline $_{electricity\_ind,\ y}$	***excluded from ER count***																				

HFO = Heavy Fuel Oil

Baseline Emissions – Industrial Sector

Year	BEy (tCO2)		FF baseline i, y (t)		NCV FF, i (GJ/t) Coal	HFO	Gasoil	Wood	LPG	Electricity	EF FF, CO2, i (tCO2/GJ) Coal	HFO	Gasoil	Wood	LPG	Electricity
2008	$BEy_{coal\_ind, y}$	1,068	$FF\ baseline_{coal\_ind, y}$	923	12.6						0.0918					
	$BEy_{HFO\_ind, y}$	25,414	$FF\ baseline_{HFO\_ind, y}$	8,294		40						0.0766				
	$BEy_{gasoil\_ind, y}$	7,558	$FF\ baseline_{gasoil\_ind, y}$	2,438			42.3						0.0733			
	$BEy_{wood\_ind, y}$	0	$FF\ baseline_{wood\_ind, y}$	0				15.6						0		
	$BEy_{LPG\_ind, y}$	110	$FF\ baseline_{LPG\_ind, y}$	37					47.6						0.0624	
	$BEy_{electricity\_ind, y}$	*excluded from ER count*	$FF\ baseline_{electricity\_ind, y}$	*excluded from ER count*												
	BEy total_ind, y	***34,150***														
2009	$BEy_{coal\_ind, y}$	2,362	$FF\ baseline_{coal\_ind, y}$	2,042	12.6						0.0918					
	$BEy_{HFO\_ind, y}$	56,205	$FF\ baseline_{HFO\_ind, y}$	18,344		40						0.0766				
	$BEy_{gasoil\_ind, y}$	16,714	$FF\ baseline_{gasoil\_ind, y}$	5,391			42.3						0.0733			
	$BEy_{wood\_ind, y}$	0	$FF\ baseline_{wood\_ind, y}$	0				15.6						0		
	$BEy_{LPG\_ind, y}$	243	$FF\ baseline_{LPG\_ind, y}$	82					47.6						0.0624	
	$BEy_{electricity\_ind, y}$	*excluded from ER count*	$FF\ baseline_{electricity\_ind, y}$	*excluded from ER count*												
	BEy total_ind, y	***75,525***														
2010	$BEy_{coal\_ind, y}$	3,887	$FF\ baseline_{coal\_ind, y}$	3,361	12.6						0.0918					
	$BEy_{HFO\_ind, y}$	92,505	$FF\ baseline_{HFO\_ind, y}$	30,191		40						0.0766				
	$BEy_{gasoil\_ind, y}$	27,510	$FF\ baseline_{gasoil\_ind, y}$	8,872			42.3						0.0733			
	$BEy_{wood\_ind, y}$	0	$FF\ baseline_{wood\_ind, y}$	0				15.6						0		
	$BEy_{LPG\_ind, y}$	401	$FF\ baseline_{LPG\_ind, y}$	135					47.6						0.0624	

Year	BEy (tCO_2)		$FF_{baseline\ i,y}$ (t)		$NCV_{FF,i}$ (GJ/t)						$EF_{FF,CO2,i}$ (tCO_2/GJ)					
					Coal	HFO	Gasoil	Wood	LPG	Electricity	Coal	HFO	Gasoil	Wood	LPG	Electricity
	$BEy_{electricity\_ind,y}$	*excluded from ER count*	*FF baseline* $_{electricity\ ind,y}$	*excluded from ER count*												
	BEy total_ind, y	***124,303***														
2011	$BEy_{coal\ ind,y}$	4,432	*FF baseline* $_{coal\ ind,y}$	3,831	12.6						0.0918					
	$BEy_{HFO\ ind,y}$	105,456	*FF baseline* $_{HFO\ ind,y}$	34,418		40						0.0766				
	$BEy_{gasoil\_ind,y}$	31,361	*FF baseline* $_{gasoil\ ind,y}$	10,115			42.3						0.0733			
	$BEy_{wood\_ind,y}$	0	*FF baseline* $_{wood\ ind,y}$	0				15.6						0		
	$BEy_{LPG\_ind,y}$	457	*FF baseline* $_{LPG\ ind,y}$	154					47.6						0.0624	
	$BEy_{electricity\_ind,y}$	*excluded from ER count*	*FF baseline* $_{electricity\ ind,y}$	*excluded from ER count*												
	BEy total_ind, y	***141,705***														
2012	$BEy_{coal\ ind,y}$	4,750	*FF baseline* $_{coal\ ind,y}$	4,107	12.6						0.0918					
	$BEy_{HFO\ ind,y}$	113,030	*FF baseline* $_{HFO\ ind,y}$	36,890		40						0.0766				
	$BEy_{gasoil\_ind,y}$	33,613	*FF baseline* $_{gasoil\ ind,y}$	10,841			42.3						0.0733			
	$BEy_{wood\_ind,y}$	0	*FF baseline* $_{wood\ ind,y}$	0				15.6						0		
	$BEy_{LPG\_ind,y}$	489	*FF baseline* $_{LPG\ ind,y}$	165					47.6						0.0624	
	$BEy_{electricity\_ind,y}$	*excluded from ER count*	*FF baseline* $_{electricity\ ind,y}$	*excluded from ER count*												
	BEy total_ind, y	***151,883***														
TOTAL BEy IND 2008-2012		***527,565***														
2013	$BEy_{coal\ ind,y}$	4,837	*FF baseline* $_{coal\ ind,y}$	4,182	12.6						0.0918					

Year	**BEy** (tCO_2)		***FF*** $_{baseline\ i,\ y}$ (t)		**NCV** $_{FF,\ i}$ (GJ/t)						**EF** $_{FF,\ CO2,\ i}$ (tCO_2/GJ)					
					Coal	HFO	Gasoil	Wood	LPG	Electricity	Coal	HFO	Gasoil	Wood	LPG	Electricity
	BEy $_{HFO\_ind,\ y}$	115,095	***FF baseline*** $_{HFO\_ind,\ y}$	37,564		40						0.0766				
	BEy $_{gasoil\_ind,\ y}$	34,227	***FF baseline*** $_{gasoil\_ind,\ y}$	11,039			42.3						0.0733			
	BEy $_{wood\_ind,\ y}$	0	***FF baseline*** $_{wood\_ind,\ y}$	0				15.6						0		
	BEy $_{LPG\_ind,\ y}$	498	***FF baseline*** $_{LPG\_ind,\ y}$	168					47.6						0.0624	
	BEy $_{electricity\_ind,\ y}$	***excluded from ER count***	***FF baseline*** $_{electricity\_ind,\ y}$	***excluded from ER count***												
	BEy total_ind, y	***154,657***														
2014	***BEy*** $_{coal\_ind,\ y}$	4,837	***FF baseline*** $_{coal\_ind,\ y}$	4,182	12.6						0.0918					
	BEy $_{HFO\_ind,\ y}$	115,095	***FF baseline*** $_{HFO\_ind,\ y}$	37,564		40						0.0766				
	BEy $_{gasoil\_ind,\ y}$	34,227	***FF baseline*** $_{gasoil\_ind,\ y}$	11,039			42.3						0.0733			
	BEy $_{wood\_ind,\ y}$	0	***FF baseline*** $_{wood\_ind,\ y}$	0				15.6						0		
	BEy $_{LPG\_ind,\ y}$	498	***FF baseline*** $_{LPG\_ind,\ y}$	168					47.6						0.0624	
	BEy $_{electricity\_ind,\ y}$	***excluded from ER count***	***FF baseline*** $_{electricity\_ind,\ y}$	***excluded from ER count***												
	BEy total_ind, y	***154,657***														
2015	***BEy*** $_{coal\_ind,\ y}$	4,837	***FF baseline*** $_{coal\_ind,\ y}$	4,182	12.6						0.0918					
	BEy $_{HFO\_ind,\ y}$	115,095	***FF baseline*** $_{HFO\_ind,\ y}$	37,564		40						0.0766				
	BEy $_{gasoil\_ind,\ y}$	34,227	***FF baseline*** $_{gasoil\_ind,\ y}$	11,039			42.3						0.0733			
	BEy $_{wood\_ind,\ y}$	0	***FF baseline*** $_{wood\_ind,\ y}$	0				15.6						0		
	BEy $_{LPG\_ind,\ y}$	498	***FF baseline*** $_{LPG\_ind,\ y}$	168					47.6						0.0624	
	BEy $_{electricity\_ind,\ y}$	***excluded from ER count***	***FF baseline*** $_{electricity\_ind,\ y}$	***excluded from ER count***												

Year	**BEy** (tCO_2)		***FF*** $_{baseline\ i,\ y}$ (t)		**NCV** $_{FF,\ i}$ (GJ/t)						**EF** $_{FF,\ CO2,\ i}$ (tCO_2/GJ)					
					Coal	HFO	Gasoil	Wood	LPG	Electricity	Coal	HFO	Gasoil	Wood	LPG	Electricity
	BEy* total_*ind, y	***154,657***														
2016	$BEy_{coal\_ind,\ y}$	4,837	$FF\ baseline_{coal\_ind,\ y}$	4,182	12.6						0.0918					
	$BEy_{HFO\_ind,\ y}$	115,095	$FF\ baseline_{HFO\_ind,\ y}$	37,564		40						0.0766				
	$BEy_{gasoil\_ind,\ y}$	34,227	$FF\ baseline_{gasoil\_ind,\ y}$	11,039			42.3						0.0733			
	$BEy_{wood\_ind,\ y}$	0	$FF\ baseline_{wood\_ind,\ y}$	0				15.6						0		
	$BEy_{LPG\_ind,\ y}$	498	$FF\ baseline_{LPG\_ind,\ y}$	168					47.6						0.0624	
	$BEy_{electricity\_ind,\ y}$	***excluded from ER count***	$FF\ baseline_{electricity\_ind,\ y}$	***excluded from ER count***												
	BEy* total_*ind, y	***154,657***														
2017	$BEy_{coal\_ind,\ y}$	4,837	$FF\ baseline_{coal\_ind,\ y}$	4,182	12.6						0.0918					
	$BEy_{HFO\_ind,\ y}$	115,095	$FF\ baseline_{HFO\_ind,\ y}$	37,564		40						0.0766				
	$BEy_{gasoil\_ind,\ y}$	34,227	$FF\ baseline_{gasoil\_ind,\ y}$	11,039			42.3						0.0733			
	$BEy_{wood\_ind,\ y}$	0	$FF\ baseline_{wood\_ind,\ y}$	0				15.6						0		
	$BEy_{LPG\_ind,\ y}$	498	$FF\ baseline_{LPG\_ind,\ y}$	168					47.6						0.0624	
	$BEy_{electricity\_ind,\ y}$	***excluded from ER count***	$FF\ baseline_{electricity\_ind,\ y}$	***excluded from ER count***												
	BEy* total_*ind, y	***154,657***														
2018	$BEy_{coal\_ind,\ y}$	4,837	$FF\ baseline_{coal\_ind,\ y}$	4,182	12.6						0.0918					
	$BEy_{HFO\_ind,\ y}$	115,095	$FF\ baseline_{HFO\_ind,\ y}$	37,564		40						0.0766				
	$BEy_{gasoil\_ind,\ y}$	34,227	$FF\ baseline_{gasoil\_ind,\ y}$	11,039			42.3						0.0733			
	$BEy_{wood\_ind,\ y}$	0	$FF\ baseline_{wood\_ind,\ y}$	0				15.6						0		
	$BEy_{LPG\_ind,\ y}$	498	$FF\ baseline_{LPG\_ind,\ y}$	168					47.6						0.0624	

Year	BEy (tCO_2)		$FF_{baseline\ i,y}$ (t)		$NCV_{FF,i}$ (GJ/t)						$EF_{FF,CO2,i}$ (tCO_2/GJ)					
					Coal	HFO	Gasoil	Wood	LPG	Electricity	Coal	HFO	Gasoil	Wood	LPG	Electricity
	$BEy_{electricity\_ind,y}$	*excluded from ER count*	$FF\ baseline_{electricity\ ind,y}$	*excluded from ER count*												
	$BEy\ total\_ind,y$	*154,657*														
2019	$BEy_{coal\ ind,y}$	4,837	$FF\ baseline_{coal\ ind,y}$	4,182	12.6						0.0918					
	$BEy_{HFO\ ind,y}$	115,095	$FF\ baseline_{HFO\ ind,y}$	37,564		40						0.0766				
	$BEy_{gasoil\_ind,y}$	34,227	$FF\ baseline_{gasoil\ ind,y}$	11,039			42.3						0.0733			
	$BEy_{wood\_ind,y}$	0	$FF\ baseline_{wood\ ind,y}$	0				15.6						0		
	$BEy_{LPG\_ind,y}$	498	$FF\ baseline_{LPG\ ind,y}$	168					47.6						0.0624	
	$BEy_{electricity\_ind,y}$	*excluded from ER count*	$FF\ baseline_{electricity\ ind,y}$	*excluded from ER count*												
	$BEy\ total\_ind,y$	*154,657*														
2020	$BEy_{coal\ ind,y}$	4,837	$FF\ baseline_{coal\ ind,y}$	4,182	12.6						0.0918					
	$BEy_{HFO\ ind,y}$	115,095	$FF\ baseline_{HFO\ ind,y}$	37,564		40						0.0766				
	$BEy_{gasoil\_ind,y}$	34,227	$FF\ baseline_{gasoil\ ind,y}$	11,039			42.3						0.0733			
	$BEy_{wood\_ind,y}$	0	$FF\ baseline_{wood\ ind,y}$	0				15.6						0		
	$BEy_{LPG\_ind,y}$	498	$FF\ baseline_{LPG\ ind,y}$	168					47.6						0.0624	
	$BEy_{electricity\_ind,y}$	*excluded from ER count*	$FF\ baseline_{electricity\ ind,y}$	*excluded from ER count*												
	$BEy\ total\_ind,y$	*154,657*														
TOTAL BEy IND 2013-2020		***1,237,259***														
TOTAL BEy IND		***1,764,825***														

$FF_{\text{baseline i, y}}$ – Public and Administrative Sector

Year	$FF_{\text{baseline i, y}}$		$FF_{\text{project i, y}}$						$NCV_{NG,Y}$	$\varepsilon_{\text{project, i}}$	$NCV_{\text{ff, i}}$						$\varepsilon_{\text{baseline, i,y}}$					
	(t)		(Sm^3/y)						(GJ/Sm^3)	-	(GJ/t)						-					
			Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elect	Natural gas	Natural gas	Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elect	Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elect
	$FF_{\text{baseline coal public, y}}$	2,156	729,657								12.6						0.8					
	$FF_{\text{baseline HFO public, y}}$	946		1,080,067								40						0.85				
	$FF_{\text{baseline gasoil\_public, y}}$	2,010			2,511,088								42.3						0.88			
2008	$FF_{\text{baseline wood public,, y}}$	0				0			0.0331	0.9				15.6						0.65		
	$FF_{\text{baseline LPG public, y}}$	0					0								47.6						0.9	
	$FF_{\text{baseline electricity\_pub, y}}$	***excluded from ER count***																				
	$FF_{\text{baseline coal public, y}}$	4,516	1,527,991								12.6						0.8					
	$FF_{\text{baseline HFO public, y}}$	1,982		2,261,792								40						0.85				
	$FF_{\text{baseline gasoil public, y}}$	4,208			5,258,523								42.3						0.88			
2009	$FF_{\text{baseline wood public, y}}$	0				0			0.0331	0.9				15.6						0.65		
	$FF_{\text{baseline LPG public, y}}$	0					0								47.6						0.9	
	$FF_{\text{baseline electricity\_pub, y}}$	***excluded from ER count***																				
	$FF_{\text{baseline coal\_public, y}}$	7,250	2,453,018								12.6						0.8					
	$FF_{\text{baseline HFO\_public y}}$	3,181		3,631,051								40						0.85				
	$FF_{\text{baseline gasoil\_public y}}$	6,756			8,441,966								42.3						0.88			
2010	$FF_{\text{baseline wood public, y}}$	0				0			0.0331	0.9				15.6						0.65		
	$FF_{\text{baseline LPG public y}}$	0					0								47.6						0.9	
	$FF_{\text{baseline electricity pub, y}}$	***excluded from ER count***																				

Year	$FF_{baseline\ i,y}$		$FF_{project\ i,y}$						$NCV_{NG,Y}$	$\varepsilon_{project,\ i}$	$NCV_{ff,\ i}$						$\varepsilon_{baseline,\ i,y}$					
	(t)		(Sm^3/y)						(GJ/Sm^3)	-	(GJ/t)						-					
			Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elect	Natural gas	Natural gas	Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elect	Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elect
2011	***FF baseline*** $_{coal\ public,\ y}$	7,964	2,694,703						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_public,\ y}$	3,495		3,988,804								40						0.85				
	FF baseline $_{gasoil\ public,y}$	7,422			9,273,718								42.3						0.88			
	FF baseline $_{wood\_public,\ y}$	0				0								15.6						0.65		
	FF baseline $_{LPG\_public,\ y}$	0					0								47.6						0.9	
	FF baseline $_{electricity\_pub,\ y}$	***excluded from ER count***																				
2012	***FF baseline*** $_{coal\ public,\ y}$	8,475	2,867,713						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_public,\ y}$	3,719		4,244,899								40						0.85				
	FF baseline $_{gasoil\ public,\ y}$	7,898			9,869,123								42.3						0.88			
	FF baseline $_{wood\ public,\ y}$	0				0								15.6						0.65		
	FF baseline $_{LPG\_public,\ y}$	0					0								47.6						0.9	
	FF baseline $_{electricity\_pub,\ y}$	***excluded from ER count***																				
2013	***FF baseline*** $_{coal\ public,\ y}$	8,612	2,914,029						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_public,\ y}$	3,779		4,313,459								40						0.85				
	FF baseline $_{gasoil\ public,\ y}$	8,026			10,028,520								42.3						0.88			
	FF baseline $_{wood\ public,\ y}$	0				0								15.6						0.65		
	FF baseline $_{LPG\_public,\ y}$	0					0								47.6						0.9	
	FF baseline $_{electricity\_pub,\ y}$	***excluded from ER count***																				

Year	$FF_{baseline\ i,y}$		$FF_{project\ i,y}$						$NCV_{NG,Y}$	$\varepsilon_{project,i}$	$NCV_{ff,i}$						$\varepsilon_{baseline,i,y}$					
	(t)		(Sm^3/y)						(GJ/Sm^3)	-	(GJ/t)						-					
			Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elect	Natural gas	Natural gas	Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elect	Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elect
	***FF baseline** coal_public, y*	8,612	2,914,029								12.6						0.8					
	***FF baseline** HFO_public, y*	3,779		4,313,459								40						0.85				
	***FF baseline** gasoil_public, y*	8,026			10,028,520								42.3						0.88			
2014	***FF baseline** wood public, y*	0				0			0.0331	0.9				15.6						0.65		
	***FF baseline** LPG_public, y*	0					0								47.6						0.9	
	***FF baseline** electricity_pub, y*	***excluded from ER count***																				
	***FF baseline** coal_ public, y*	8,612	2,914,029								12.6						0.8					
	***FF baseline** HFO_public, y*	3,779		4,313,459								40						0.85				
	***FF baseline** gasoil_public, y*	8,026			10,028,520								42.3						0.88			
2015	***FF baseline** wood_public, y*	0				0			0.0331	0.9				15.6						0.65		
	***FF baseline** LPG_public, y*	0					0								47.6						0.9	
	***FF baseline** electricity pub, y*	***excluded from ER count***																				
	***FF baseline** coal_public, y*	8,612	2,914,029								12.6						0.8					
	***FF baseline** HFO_ public, y*	3,779		4,313,459								40						0.85				
	***FF baseline** gasoil_public, y*	8,026			10,028,520								42.3						0.88			
2016	***FF baseline** wood_public, y*	0				0			0.0331	0.9				15.6						0.65		
	***FF baseline** LPG_public, y*	0					0								47.6						0.9	
	***FF baseline** electricity_pub, y*	***excluded from ER count***																				

Year	$FF_{baseline\ i,y}$ (t)		$FF_{project\ i,y}$ (Sm^3/y)						$NCV_{NG,Y}$ (GJ/Sm^3)	$\varepsilon_{project,i}$ -	$NCV_{ff,i}$ (GJ/t)						$\varepsilon_{baseline,i,y}$ -					
			Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elect	Natural gas	Natural gas	Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elect	Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elect
	FF baseline $_{coal\_public,y}$	8,612	2,914,029								12.6						0.8					
	FF baseline $_{HFO\_public,y}$	3,779		4,313,459								40						0.85				
	FF baseline $_{gasoil\_public,y}$	8,026			10,028,520								42.3						0.88			
2017	***FF baseline*** $_{wood\_public,y}$	0				0			0.0331	0.9				15.6						0.65		
	FF baseline $_{LPG\_public,y}$	0					0								47.6						0.9	
	FF baseline $_{electricity\_pub,y}$	***excluded from ER count***																				
	FF baseline $_{coal\_public,y}$	8,612	2,914,029								12.6						0.8					
	FF baseline $_{HFO\_public,y}$	3,779		4,313,459								40						0.85				
	FF baseline $_{gasoil\_public,y}$	8,026			10,028,520								42.3						0.88			
2018	***FF baseline*** $_{wood\_public,y}$	0				0			0.0331	0.9				15.6						0.65		
	FF baseline $_{LPG\_public,y}$	0					0								47.6						0.9	
	FF baseline $_{electricity\_pub,y}$	***excluded from ER count***																				
	FF baseline $_{coal\_public,y}$	8,612	2,914,029								12.6						0.8					
	FF baseline $_{HFO\_public,y}$	3,779		4,313,459								40						0.85				
	FF baseline $_{gasoil\_public,y}$	8,026			10,028,520								42.3						0.88			
2019	***FF baseline*** $_{wood\_public,y}$	0				0			0.0331	0.9				15.6						0.65		
	FF baseline $_{LPG\_public,y}$	0					0								47.6						0.9	
	FF baseline $_{electricity\_pub,y}$	***excluded from ER count***																				

Year	***FF*** $_{baseline\ i,\ y}$		**FF** $_{project\ i,\ y}$						**NCV** $_{NG,Y}$	**ε** $_{project,\ i}$	**NCV** $_{ff,\ i}$						**ε** $_{baseline,\ i,y}$					
	(t)		(Sm^3/y)						(GJ/Sm^3)	-	(GJ/t)						-					
			Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elect	Natural gas	Natural gas	Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elect	Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elect
2020	***FF baseline*** $_{coal\_public,\ y}$	8,612	2,914,029								12.6						0.8					
	FF baseline $_{HFO\_\ public,\ y}$	3,779		4,313,459								40						0.85				
	FF baseline $_{gasoil\_public,\ y}$	8,026			10,028,520								42.3						0.88			
	FF baseline $_{wood\_public,\ y}$	0				0			0.0331	0.9				15.6						0.65		
	FF baseline $_{LPG\_public,\ y}$	0					0								47.6						0.9	
	FF baseline $_{electricity\_pub,\ y}$	***excluded from ER count***																				

HFO = Heavy Fuel Oil

Baseline Emissions –Public and Administrative Sector

Year	BEy (tCO_2)		FF $_{baseline\ i,y}$ (t)		NCV $_{FF,i}$ (GJ/t)						$EF_{FF,CO2,i}$ (tCO_2/GJ)					
					Coal	HFO	Gasoil	Wood	LPG	Electricity	Coal	HFO	Gasoil	Wood	LPG	Electricity
2008	*BEy* $_{coal\_public,y}$	2,494	*FF baseline* $_{coal\_public,y}$	2,156	12.6						0.0918					
	BEy $_{HFO\_public,y}$	2,899	*FF baseline* $_{HFO\_public,y}$	946		40						0.0766				
	BEy $_{gasoil\_public,y}$	6,233	*FF baseline* $_{gasoil\_public,y}$	2,010			42.3						0.0733			
	BEy $_{wood\_public,y}$	0	*FF baseline* $_{wood\_public,y}$	0				15.6						0		
	BEy $_{LPG\_public,y}$	0	*FF baseline* $_{LPG\_public,y}$	0					47.6						0.0624	
	BEy $_{electricity\_public,y}$	***excluded from ER count***	*FF baseline* $_{electricity\_public,y}$	***excluded from ER count***												
	BEy total_public, y	***11,627***														
2009	*BEy* $_{coal\_public,y}$	5,223	*FF baseline* $_{coal\_public,y}$	4,516	12.6						0.0918					
	BEy $_{HFO\_public,y}$	6,071	*FF baseline* $_{HFO\_public,y}$	1,982		40						0.0766				
	BEy $_{gasoil\_public,y}$	13,054	*FF baseline* $_{gasoil\_public,y}$	4,208			42.3						0.0733			
	BEy $_{wood\_public,y}$	0	*FF baseline* $_{wood\_public,y}$	0				15.6						0		
	BEy $_{LPG\_public,y}$	0	*FF baseline* $_{LPG\_public,y}$	0					47.6						0.0624	
	BEy $_{electricity\_public,y}$	***excluded from ER count***	*FF baseline* $_{electricity\_public,y}$	***excluded from ER count***												
	BEy total_public, y	***24,348***														
2010	*BEy* $_{coal\_public,y}$	8,385	*FF baseline* $_{coal\_public,y}$	7,250	12.6						0.0918					
	BEy $_{HFO\_public,y}$	9,747	*FF baseline* $_{HFO\_public,y}$	3,181		40						0.0766				
	BEy $_{gasoil\_public,y}$	20,956	*FF baseline* $_{gasoil\_public,y}$	6,756			42.3						0.0733			
	BEy $_{wood\_public,y}$	0	*FF baseline* $_{wood\_public,y}$	0				15.6						0		
	BEy $_{LPG\_public,y}$	0	*FF baseline* $_{LPG\_public,y}$	0					47.6						0.0624	
	BEy $_{electricity\_public,y}$	***excluded from ER count***	*FF baseline* $_{electricity\_public,y}$	***excluded from ER***												

Year	BEy (tCO_2)		*FF* $_{baseline\ i,\ y}$ (t)		NCV $_{FF,\ i}$ (GJ/t)						$EF_{FF,\ CO2,\ i}$ (tCO_2/GJ)					
					Coal	HFO	Gasoil	Wood	LPG	Electricity	Coal	HFO	Gasoil	Wood	LPG	Electricity
				count												
	***BEy* total_public, y**	***39,088***														
2011	*BEy* $_{coal\_public,\ y}$	9,212	***FF baseline*** $_{coal\_public,\ y}$	7,964	12.6						0.0918					
	BEy $_{HFO\_public,\ y}$	10,707	***FF baseline*** $_{HFO\_public,\ y}$	3,495		40						0.0766				
	BEy $_{gasoil\_public,\ y}$	23,021	***FF baseline*** $_{gasoil\_public,\ y}$	7,422			42.3						0.0733			
	BEy $_{wood\_public,\ y}$	0	***FF baseline*** $_{wood\_public,\ y}$	0				15.6						0		
	BEy $_{LPG\_public,\ y}$	0	***FF baseline*** $_{LPG\_public,\ y}$	0					47.6						0.0624	
	BEy $_{electricity\_public,\ y}$	***excluded from ER count***	***FF baseline*** $_{electricity\_public,\ y}$	***excluded from ER count***												
	***BEy* total_public, y**	***42,940***														
2012	*BEy* $_{coal\_public,\ y}$	9,803	***FF baseline*** $_{coal\_public,\ y}$	8,475	12.6						0.0918					
	BEy $_{HFO\_public,\ y}$	11,394	***FF baseline*** $_{HFO\_public,\ y}$	3,719		40						0.0766				
	BEy $_{gasoil\_public,\ y}$	24,499	***FF baseline*** $_{gasoil\_public,\ y}$	7,898			42.3						0.0733			
	BEy $_{wood\_public,\ y}$	0	***FF baseline*** $_{wood\_public,\ y}$	0				15.6						0		
	BEy $_{LPG\_public,\ y}$	0	***FF baseline*** $_{LPG\_public,\ y}$	0					47.6						0.0624	
	BEy $_{electricity\_public,\ y}$	***excluded from ER count***	***FF baseline*** $_{electricity\_public,\ y}$	***excluded from ER count***												
	***BEy* total_public, y**	***45,696***														
TOTAL BEy IND 2008-2012		***163,699***														
2013	*BEy* $_{coal\_public,\ y}$	9,961	***FF baseline*** $_{coal\_public,\ y}$	8,612	12.6						0.0918					
	BEy $_{HFO\_public,\ y}$	11,578	***FF baseline*** $_{HFO\_public,\ y}$	3,779		40						0.0766				
	BEy $_{gasoil\_public,\ y}$	24,895	***FF baseline*** $_{gasoil\_public,\ y}$	8,026			42.3						0.0733			

Year	BEy (tCO$_2$)		$FF_{baseline\ i, y}$ (t)		$NCV_{FF, i}$ (GJ/t)						$EF_{FF, CO2, i}$ (tCO$_2$/GJ)					
					Coal	HFO	Gasoil	Wood	LPG	Electricity	Coal	HFO	Gasoil	Wood	LPG	Electricity
	$BEy_{wood\_public, y}$	0	$FF\ baseline_{wood\_public, y}$	0				15.6						0		
	$BEy_{LPG\_public, y}$	0	$FF\ baseline_{LPG\_public, y}$	0					47.6						0.0624	
	$BEy_{electricity\_public, y}$	*excluded from ER count*	$FF\ baseline_{electricity\_public, y}$	*excluded from ER count*												
	BEy total_public, y	***46,434***														
2014	$BEy_{coal\_public, y}$	9,961	$FF\ baseline_{coal\_public, y}$	8,612	12.6						0.0918					
	$BEy_{HFO\_public, y}$	11,578	$FF\ baseline_{HFO\_public, y}$	3,779		40						0.0766				
	$BEy_{gasoil\_public, y}$	24,895	$FF\ baseline_{gasoil\_public, y}$	8,026			42.3						0.0733			
	$BEy_{wood\_public, y}$	0	$FF\ baseline_{wood\_public, y}$	0				15.6						0		
	$BEy_{LPG\_public, y}$	0	$FF\ baseline_{LPG\_public, y}$	0					47.6						0.0624	
	$BEy_{electricity\_public, y}$	*excluded from ER count*	$FF\ baseline_{electricity\_public, y}$	*excluded from ER count*												
	BEy total_public, y	***46,434***														
2015	$BEy_{coal\_public, y}$	9,961	$FF\ baseline_{coal\_public, y}$	8,612	12.6						0.0918					
	$BEy_{HFO\_public, y}$	11,578	$FF\ baseline_{HFO\_public, y}$	3,779		40						0.0766				
	$BEy_{gasoil\_public, y}$	24,895	$FF\ baseline_{gasoil\_public, y}$	8,026			42.3						0.0733			
	$BEy_{wood\_public, y}$	0	$FF\ baseline_{wood\_public, y}$	0				15.6						0		
	$BEy_{LPG\_public, y}$	0	$FF\ baseline_{LPG\_public, y}$	0					47.6						0.0624	
	$BEy_{electricity\_public, y}$	*excluded from ER count*	$FF\ baseline_{electricity\_public, y}$	*excluded from ER count*												
	BEy total_public, y	***46,434***														
2016	$BEy_{coal\_public, y}$	9,961	$FF\ baseline_{coal\_public, y}$	8,612	12.6						0.0918					
	$BEy_{HFO\_public, y}$	11,578	$FF\ baseline_{HFO\_public, y}$	3,779		40						0.0766				

Year	BEy (tCO$_2$)		$FF_{baseline\ i,y}$ (t)		$NCV_{FF,i}$ (GJ/t) Coal	HFO	Gasoil	Wood	LPG	Electricity	$EF_{FF,CO2,i}$ (tCO$_2$/GJ) Coal	HFO	Gasoil	Wood	LPG	Electricity
	$BEy_{gasoil\_public,y}$	24,895	$FF\ baseline_{gasoil\_public,y}$	8,026			42.3						0.0733			
	$BEy_{wood\_public,y}$	0	$FF\ baseline_{wood\_public,y}$	0				15.6						0		
	$BEy_{LPG\_public,y}$	0	$FF\ baseline_{LPG\_public,y}$	0					47.6						0.0624	
	$BEy_{electricity\_public,y}$	***excluded from ER count***	$FF\ baseline_{electricity\_public,y}$	***excluded from ER count***												
	BEy total_public, y	***46,434***														
2017	$BEy_{coal\_public,y}$	9,961	$FF\ baseline_{coal\_public,y}$	8,612	12.6						0.0918					
	$BEy_{HFO\_public,y}$	11,578	$FF\ baseline_{HFO\_public,y}$	3,779		40						0.0766				
	$BEy_{gasoil\_public,y}$	24,895	$FF\ baseline_{gasoil\_public,y}$	8,026			42.3						0.0733			
	$BEy_{wood\_public,y}$	0	$FF\ baseline_{wood\_public,y}$	0				15.6						0		
	$BEy_{LPG\_public,y}$	0	$FF\ baseline_{LPG\_public,y}$	0					47.6						0.0624	
	$BEy_{electricity\_public,y}$	***excluded from ER count***	$FF\ baseline_{electricity\_public,y}$	***excluded from ER count***												
	BEy total_public, y	***46,434***														
2018	$BEy_{coal\_public,y}$	9,961	$FF\ baseline_{coal\_public,y}$	8,612	12.6						0.0918					
	$BEy_{HFO\_public,y}$	11,578	$FF\ baseline_{HFO\_public,y}$	3,779		40						0.0766				
	$BEy_{gasoil\_public,y}$	24,895	$FF\ baseline_{gasoil\_public,y}$	8,026			42.3						0.0733			
	$BEy_{wood\_public,y}$	0	$FF\ baseline_{wood\_public,y}$	0				15.6						0		
	$BEy_{LPG\_public,y}$	0	$FF\ baseline_{LPG\_public,y}$	0					47.6						0.0624	
	$BEy_{electricity\_public,y}$	***excluded from ER count***	$FF\ baseline_{electricity\_public,y}$	***excluded from ER count***												
	BEy total_public, y	***46,434***														

Year	BEy (tCO_2)		$FF_{baseline\ i,y}$ (t)		$NCV_{FF,i}$ (GJ/t)						$EF_{FF,CO2,i}$ (tCO_2/GJ)					
					Coal	HFO	Gasoil	Wood	LPG	Electricity	Coal	HFO	Gasoil	Wood	LPG	Electricity
2019	$BEy_{coal\_public,y}$	9,961	$FF\ baseline_{coal\_public,y}$	8,612	12.6						0.0918					
	$BEy_{HFO\_public,y}$	11,578	$FF\ baseline_{HFO\_public,y}$	3,779		40						0.0766				
	$BEy_{gasoil\_public,y}$	24,895	$FF\ baseline_{gasoil\_public,y}$	8,026			42.3						0.0733			
	$BEy_{wood\_public,y}$	0	$FF\ baseline_{wood\_public,y}$	0				15.6						0		
	$BEy_{LPG\_public,y}$	0	$FF\ baseline_{LPG\_public,y}$	0					47.6						0.0624	
	$BEy_{electricity\_public,y}$	***excluded from ER count***	$FF\ baseline_{electricity\_public,y}$	***excluded from ER count***												
	BEy total_public, y	***46,434***														
2020	$BEy_{coal\_public,y}$	9,961	$FF\ baseline_{coal\_public,y}$	8,612	12.6						0.0918					
	$BEy_{HFO\_public,y}$	11,578	$FF\ baseline_{HFO\_public,y}$	3,779		40						0.0766				
	$BEy_{gasoil\_public,y}$	24,895	$FF\ baseline_{gasoil\_public,y}$	8,026			42.3						0.0733			
	$BEy_{wood\_public,y}$	0	$FF\ baseline_{wood\_public,y}$	0				15.6						0		
	$BEy_{LPG\_public,y}$	0	$FF\ baseline_{LPG\_public,y}$	0					47.6						0.0624	
	$BEy_{electricity\_public,y}$	***excluded from ER count***	$FF\ baseline_{electricity\_public,y}$	***excluded from ER count***												
	BEy total_public, y	***46,434***														
TOTAL BEy IND 2013-2020		**371,475**														
TOTAL BEy IND 2008-2020		**535,175**														

HFO = Heavy Fuel Oil

FF $_{baseline\ i,\ y}$ – Residential sector

Year	*FF* $_{baseline\ i,\ y}$		*FF* $_{project\ i,\ y}$						NCV $_{NG,Y}$	$\varepsilon_{project,\ i}$	NCV $_{ff,\ i}$						$\varepsilon_{baseline,\ i,y}$					
	(t)		(Sm^3/y)						(GJ/Sm^3)	-	(GJ/t)						-					
			Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elec	Natural gas	Natural gas	Coal	Heavy Fuel Oil	Gasoil	Wood	LPG	Elec	Coal	Heavy Fuel Oil	Gasoil	Wood	LPG	Elec
2008	*FF baseline* $_{coal\_resid,\ y}$	***0***	0						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_resid,\ y}$	***0***		0								40						0.85				
	FF baseline $_{gasoil\_resid,\ y}$	***230***			287,133								42.3						0.88			
	FF baseline $_{wood\_resid,\ y}$	***0***				0								15.6						0.65		
	FF baseline $_{LPG\_resid,\ y}$	***2,270***					3,264,464								47.6						0.9	
	FF baseline $_{electricity\_res,\ y}$	***excluded from ER count***																				
2009	*FF baseline* $_{coal\_resid,\ y}$	***0***	0						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_resid,\ y}$	***0***		0								40						0.85				
	FF baseline $_{gasoil\_resid,\ y}$	***662***			826,687								42.3						0.88			
	FF baseline $_{wood\_resid,\ y}$	***0***				0								15.6						0.65		
	FF baseline $_{LPG\_resid,\ y}$	***6,536***					9,398,736								47.6						0.9	
	FF baseline $_{electricity\_res,\ y}$	***excluded from ER count***																				
2010	*FF baseline* $_{coal\_resid,\ y}$	***0***	0						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_resid,\ y}$	***0***		0								40						0.85				
	FF baseline $_{gasoil\_resid,\ y}$	***1,107***			1,383,039								42.3						0.88			
	FF baseline $_{wood\_resid,\ y}$	***0***				0								15.6						0.65		
	FF baseline $_{LPG\_resid,\ y}$	***10,934***					15,723,992								47.6						0.9	

Year	$FF_{baseline\ i,y}$		$FF_{project\ i,y}$						$NCV_{NG,Y}$	$\varepsilon_{project,i}$	$NCV_{ff,i}$						$\varepsilon_{baseline,i,y}$					
	(t)		(Sm^3/y)						(GJ/Sm^3)	-	(GJ/t)						-					
			Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elec	Natural gas	Natural gas	Coal	Heavy Fuel Oil	Gasoil	Wood	LPG	Elec	Coal	Heavy Fuel Oil	Gasoil	Wood	LPG	Elec
	FF baseline $_{electricity\_res,y}$	***excluded from ER count***																				
2011	***FF baseline*** $_{coal\_resid,y}$	***0***	0						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_resid,y}$	***0***		0								40						0.85				
	FF baseline $_{gasoil\_resid,y}$	***1,563***			1,952,500								42.3						0.88			
	FF baseline $_{wood\_resid,y}$	***0***				0								15.6						0.65		
	FF baseline $_{LPG\_resid,y}$	***15,436***					22,198,283								47.6						0.9	
	FF baseline $_{electricity\_res,y}$	***excluded from ER count***																				
2012	***FF baseline*** $_{coal\_resid,y}$	***0***	0						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_resid,y}$	***0***		0								40						0.85				
	FF baseline $_{gasoil\_resid,y}$	***2,044***			2,554,328								42.3						0.88			
	FF baseline $_{wood\_resid,y}$	***0***				0								15.6						0.65		
	FF baseline $_{LPG\_resid,y}$	***20,194***					29,040,563								47.6						0.9	
	FF baseline $_{electricity\_res,y}$	***excluded from ER count***																				
2013	***FF baseline*** $_{coal\_resid,y}$	***0***	0						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_resid,y}$	***0***		0								40						0.85				
	FF baseline $_{gasoil\_resid,y}$	***2,475***			3,093,199								42.3						0.88			
	FF baseline $_{wood\_resid,y}$	***0***				0								15.6						0.65		
	FF baseline $_{LPG\_resid,y}$	***24,454***					35,167,070								47.6						0.9	

Year	$FF_{baseline\ i,y}$		$FF_{project\ i,y}$						$NCV_{NG,Y}$	$\varepsilon_{project,i}$	$NCV_{ff,i}$						$\varepsilon_{baseline,i,y}$					
	(t)		(Sm^3/y)						(GJ/Sm^3)	-	(GJ/t)						-					
			Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elec	Natural gas	Natural gas	Coal	Heavy Fuel Oil	Gasoil	Wood	LPG	Elec	Coal	Heavy Fuel Oil	Gasoil	Wood	LPG	Elec
	FF baseline $_{electricity\_res,y}$	***excluded from ER count***																				
2014	***FF baseline*** $_{coal\_resid,y}$	***0***	0						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_resid,y}$	***0***		0								40						0.85				
	FF baseline $_{gasoil\_resid,y}$	***2,852***			3,563,102								42.3						0.88			
	FF baseline $_{wood\_resid,y}$	***0***				0								15.6						0.65		
	FF baseline $_{LPG\_resid,y}$	***28,169***					40,509,473								47.6						0.9	
	FF baseline $_{electricity\_res,y}$	***excluded from ER count***																				
2015	***FF baseline*** $_{coal\_resid,y}$	***0***	0						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_resid,y}$	***0***		0								40						0.85				
	FF baseline $_{gasoil\_resid,y}$	***3,171***			3,961,923								42.3						0.88			
	FF baseline $_{wood\_resid,y}$	***0***				0								15.6						0.65		
	FF baseline $_{LPG\_resid,y}$	***31,322***					45,043,727								47.6						0.9	
	FF baseline $_{electricity\_res,y}$	***excluded from ER count***																				
2016	***FF baseline*** $_{coal\_resid,y}$	***0***	0						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_resid,y}$	***0***		0								40						0.85				
	FF baseline $_{gasoil\_resid,y}$	***3,457***			4,319,152								42.3						0.88			
	FF baseline $_{wood\_resid,y}$	***0***				0								15.6						0.65		
	FF baseline $_{LPG\_resid,y}$	***34,147***					49,105,130								47.6						0.9	

Year	$FF_{baseline\ i,y}$		$FF_{project\ i,y}$						$NCV_{NG,Y}$	$\varepsilon_{project,i}$	$NCV_{ff,i}$						$\varepsilon_{baseline,i,y}$					
	(t)		(Sm^3/y)						(GJ/Sm^3)	-	(GJ/t)						-					
			Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elec	Natural gas	Natural gas	Coal	Heavy Fuel Oil	Gasoil	Wood	LPG	Elec	Coal	Heavy Fuel Oil	Gasoil	Wood	LPG	Elec
	FF baseline $_{electricity\_res,y}$	***excluded from ER count***																				
2017	***FF baseline*** $_{coal\_resid,y}$	***0***	0						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_resid,y}$	***0***		0								40						0.85				
	FF baseline $_{gasoil\_resid,y}$	***3,683***			4,601,604								42.3						0.88			
	FF baseline $_{wood\_resid,y}$	***0***				0								15.6						0.65		
	FF baseline $_{LPG\_resid,y}$	***36,380***					52,316,368								47.6						0.9	
	FF baseline $_{electricity\_res,y}$	***excluded from ER count***																				
2018	***FF baseline*** $_{coal\_esid,y}$	***0***	0						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_resid,y}$	***0***		0								40						0.85				
	FF baseline $_{gasoil\_resid,y}$	***3,812***			4,763,239								42.3						0.88			
	FF baseline $_{wood\_resid,y}$	***0***				0								15.6						0.65		
	FF baseline $_{LPG\_resid,y}$	***37,658***					54,154,025								47.6						0.9	
	FF baseline $_{electricity\_res,y}$	***excluded from ER count***																				
2019	***FF baseline*** $_{coal\_resid,y}$	***0***	0						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_resid,y}$	***0***		0								40						0.85				
	FF baseline $_{gasoil\_resid,y}$	***3,879***			4,846,508								42.3						0.88			
	FF baseline $_{wood\_resid,y}$	***0***				0								15.6						0.65		
	FF baseline $_{LPG\_resid,y}$	***38,316***					55,100,722								47.6						0.9	

Year	$FF_{baseline\ i,y}$		$FF_{project\ i,y}$						$NCV_{NG,Y}$	$\varepsilon_{project,i}$	$NCV_{ff,i}$						$\varepsilon_{baseline,i,y}$					
	(t)		(Sm^3/y)						(GJ/Sm^3)	-	(GJ/t)						-					
			Coal	Heavy fuel oil	Gasoil	Wood	LPG	Elec	Natural gas	Natural gas	Coal	Heavy Fuel Oil	Gasoil	Wood	LPG	Elec	Coal	Heavy Fuel Oil	Gasoil	Wood	LPG	Elec
	FF baseline $_{electricity\_res,y}$	***excluded from ER count***																				
2020	***FF baseline*** $_{coal\_resid,y}$	***0***	0						0.0331	0.9	12.6						0.8					
	FF baseline $_{HFO\_resid,y}$	***0***		0								40						0.85				
	FF baseline $_{gasoil\_resid,y}$	***3,915***			4,891,583								42.3						0.88			
	FF baseline $_{wood\_resid,y}$	***0***				0								15.6						0.65		
	FF baseline $_{LPG\_resid,y}$	***38,672***					55,613,183								47.6						0.9	
	FF baseline $_{electricity\_res,y}$	***excluded from ER count***																				

HFO= Heavy Fuel Oil

Baseline Emissions –Residential Sector

Year	BEy		$FF_{baseline\ i,y}$		$NCV_{FF,i}$						$EF_{FF,CO2,i}$					
	tCO_2		(t)		(GJ/t)						tCO_2/GJ					
					Coal	HFO	Gasoil	Wood	LPG	Electricity	Coal	HFO	Gasoil	Wood	LPG	Electricity
2008	$BEy_{coal\_res,y}$	0	FF baseline $_{coal\_res,y}$	0	12.6						0.0918					
	$BEy_{HFO\_res,y}$	0	FF baseline $_{HFO\_res,y}$	0		40						0.0766				
	$BEy_{gasoil\_res,y}$	713	FF baseline $_{gasoil\_res,y}$	230			42.3						0.0733			
	$BEy_{wood\_res,y}$	0	FF baseline $_{wood\_res,y}$	0				15.6						0		
	$BEy_{LPG\_res,y}$	6,747	FF baseline $_{LPG\_res,y}$	2,270					47.6						0.0624	
	$BEy_{electricity\_res,y}$	***excluded from ER count***	FF baseline $_{electricity\_res,y}$	***excluded from ER count***												
	BEy total_res, y	***7,460***														
2009	$BEy_{coal\_res,y}$	0	FF baseline $_{coal\_res,y}$	0	12.6						0.0918					
	$BEy_{HFO\_res,y}$	0	FF baseline $_{HFO\_res,y}$	0		40						0.0766				
	$BEy_{gasoil\_res,y}$	2,052	FF baseline $_{gasoil\_res,y}$	662			42.3						0.0733			
	$BEy_{wood\_res,y}$	0	FF baseline $_{wood\_res,y}$	0				15.6						0		
	$BEy_{LPG\_res,y}$	19,425	FF baseline $_{LPG\_res,y}$	6,536					47.6						0.0624	
	$BEy_{electricity\_res,y}$	***excluded from ER count***	FF baseline $_{electricity\_res,y}$	***excluded from ER count***												
	BEy total_res, y	***21,477***														
2010	$BEy_{coal\_res,y}$	0	FF baseline $_{coal\_res,y}$	0	12.6						0.0918					
	$BEy_{HFO\_res,y}$	0	FF baseline $_{HFO\_res,y}$	0		40						0.0766				
	$BEy_{gasoil\_res,y}$	3,433	FF baseline $_{gasoil\_res,y}$	1,107			42.3						0.0733			
	$BEy_{wood\_res,y}$	0	FF baseline $_{wood\_res,y}$	0				15.6						0		
	$BEy_{LPG\_res,y}$	32,498	FF baseline $_{LPG\_res,y}$	10,934					47.6						0.0624	
	$BEy_{electricity\_res,y}$	***excluded from ER count***	FF baseline $_{electricity\_res,y}$	***excluded from ER***												

Year	BEy		FF $_{baseline\ i,\ y}$		NCV $_{FF,\ i}$						EF $_{FF,\ CO2,\ i}$					
	tCO_2		(t)		(GJ/t)						tCO_2/GJ					
					Coal	HFO	Gasoil	Wood	LPG	Electricity	Coal	HFO	Gasoil	Wood	LPG	Electricity
				count												
	BEy* total_*res, y	***35,931***														
2011	***BEy*** $_{coal\ res,\ y}$	0	***FF baseline*** $_{coal\ public,\ y}$	0	12.6						0.0918					
	BEy $_{HFO\ res,\ y}$	0	***FF baseline*** $_{HFO\ res,\ y}$	0		40						0.0766				
	BEy $_{gasoil\_res,\ y}$	4,847	***FF baseline*** $_{gasoil\_public,\ y}$	1,563			42.3						0.0733			
	BEy $_{wood\_res,\ y}$	0	***FF baseline*** $_{wood\_public,\ y}$	0				15.6						0		
	BEy $_{LPG\_res,\ y}$	45,879	***FF baseline*** $_{LPG\ res,\ y}$	15,436					47.6						0.0624	
	BEy $_{electricity\_res,\ y}$	***excluded from ER count***	***FF baseline*** $_{electricity\ public,\ y}$	***excluded from ER count***												
	BEy* total_*res, y	***50,725***														
2012	***BEy*** $_{coal\ res,\ y}$	0	***FF baseline*** $_{coal\ res,\ y}$	0	12.6						0.0918					
	BEy $_{HFO\ res,\ y}$	0	***FF baseline*** $_{HFO\ res,\ y}$	0		40						0.0766				
	BEy $_{gasoil\_res,\ y}$	6,341	***FF baseline*** $_{gasoil\ res,\ y}$	2,044			42.3						0.0733			
	BEy $_{wood\_res,\ y}$	0	***FF baseline*** $_{wood\ res,\ y}$	0				15.6						0		
	BEy $_{LPG\_res,\ y}$	60,020	***FF baseline*** $_{LPG\ res,\ y}$	20,194					47.6						0.0624	
	BEy $_{electricity\_res,\ y}$	***excluded from ER count***	***FF baseline*** $_{electricity\ res,\ y}$	***excluded from ER count***												
	BEy* total_*res, y	***66,361***														
TOTAL BEy IND 2008-2012		***181,954***														
2013	***BEy*** $_{coal\ res,\ y}$	0	***FF baseline*** $_{coal\ res,\ y}$	0	12.6						0.0918					
	BEy $_{HFO\ res,\ y}$	0	***FF baseline*** $_{HFO\ res,\ y}$	0		40						0.0766				

Year	BEy		$FF_{baseline\ i,\ y}$		$NCV_{FF,\ i}$						$EF_{FF,\ CO2,\ i}$					
	tCO_2		(t)		(GJ/t)						tCO_2/GJ					
					Coal	HFO	Gasoil	Wood	LPG	Electricity	Coal	HFO	Gasoil	Wood	LPG	Electricity
	$BEy_{gasoil\_res,\ y}$	7,679	$FF\ baseline_{gasoil\ res,\ y}$	2,475			42.3						0.0733			
	$BEy_{wood\_res,\ y}$	0	$FF\ baseline_{wood\ res,\ y}$	0				15.6						0		
	$BEy_{LPG\_res,\ y}$	72,682	$FF\ baseline_{LPG\ res,\ y}$	24,454					47.6						0.0624	
	$BEy_{electricity\_res,\ y}$	***excluded from ER count***	$FF\ baseline_{electricity\ res,\ y}$	***excluded from ER count***												
	BEy total_*res, y*	***80,361***														
2014	$BEy_{coal\ res,\ y}$	0	$FF\ baseline_{coal\ res,\ y}$	0	12.6						0.0918					
	$BEy_{HFO\ res,\ y}$	0	$FF\ baseline_{HFO\ res,\ y}$	0		40						0.0766				
	$BEy_{gasoil\_res,\ y}$	8,845	$FF\ baseline_{gasoil\ res,\ y}$	2,852			42.3						0.0733			
	$BEy_{wood\_res,\ y}$	0	$FF\ baseline_{wood\ res,\ y}$	0				15.6						0		
	$BEy_{LPG\_res,\ y}$	83,724	$FF\ baseline_{LPG\ res,\ y}$	28,169					47.6						0.0624	
	$BEy_{electricity\_res,\ y}$	***excluded from ER count***	$FF\ baseline_{electricity\ res,\ y}$	***excluded from ER count***												
	BEy total_*res, y*	***92,569***														
2015	$BEy_{coal\ res,\ y}$	0	$FF\ baseline_{coal\ res,\ y}$	0	12.6						0.0918					
	$BEy_{HFO\ res,\ y}$	0	$FF\ baseline_{HFO\ res,\ y}$	0		40						0.0766				
	$BEy_{gasoil\_res,\ y}$	9,835	$FF\ baseline_{gasoil\ res,\ y}$	3,171			42.3						0.0733			
	$BEy_{wood\_res,\ y}$	0	$FF\ baseline_{wood\ res,\ y}$	0				15.6						0		
	$BEy_{LPG\_res,\ y}$	93,095	$FF\ baseline_{LPG\ res,\ y}$	31,322					47.6						0.0624	
	$BEy_{electricity\_res,\ y}$	***excluded from ER count***	$FF\ baseline_{electricity\ res,\ y}$	***excluded from ER count***												
	BEy total_*res, y*	***102,930***														
2016	$BEy_{coal\ res,\ y}$	0	$FF\ baseline_{coal\ res,\ y}$	0	12.6						0.0918					

Year	**BEy**		***FF*** $_{baseline\ i,\ y}$		**NCV** $_{FF,\ i}$						**EF**$_{FF,\ CO2,\ i}$					
	tCO_2		(t)		(GJ/t)						tCO_2/GJ					
					Coal	HFO	Gasoil	Wood	LPG	Electricity	Coal	HFO	Gasoil	Wood	LPG	Electricity
	BEy $_{HFO\ res,\ y}$	0	***FF baseline*** $_{HFO\ res,\ y}$	0		40						0.0766				
	BEy $_{gasoil\_res,\ y}$	10,722	***FF baseline*** $_{gasoil\ res,\ y}$	3,457			42.3						0.0733			
	BEy $_{wood\_res,\ y}$	0	***FF baseline*** $_{wood\ res,\ y}$	0				15.6						0		
	BEy $_{LPG\_res,\ y}$	101,489	***FF baseline*** $_{LPG\ res,\ y}$	34,147					47.6						0.0624	
	BEy $_{electricity\_res,\ y}$	***excluded from ER count***	***FF baseline*** $_{electricity\ res,\ y}$	***excluded from ER count***												
	BEy* total_*res, y	***112,211***														
2017	***BEy*** $_{coal\ res,\ y}$	0	***FF baseline*** $_{coal\ res,\ y}$	0	12.6						0.0918					
	BEy $_{HFO\ res,\ y}$	0	***FF baseline*** $_{HFO\ res,\ y}$	0		40						0.0766				
	BEy $_{gasoil\_res,\ y}$	11,423	***FF baseline*** $_{gasoil\ res,\ y}$	3,683			42.3						0.0733			
	BEy $_{wood\_res,\ y}$	0	***FF baseline*** $_{wood\ res,\ y}$	0				15.6						0		
	BEy $_{LPG\_res,\ y}$	108,126	***FF baseline*** $_{LPG\ res,\ y}$	36,380					47.6						0.0624	
	BEy $_{electricity\_res,\ y}$	***excluded from ER count***	***FF baseline*** $_{electricity\ res,\ y}$	***excluded from ER count***												
	BEy* total_*res, y	***119,549***														
2018	***BEy*** $_{coal\ res,\ y}$	0	***FF baseline*** $_{coal\ res,\ y}$	0	12.6						0.0918					
	BEy $_{HFO\ res,\ y}$	0	***FF baseline*** $_{HFO\ res,\ y}$	0		40						0.0766				
	BEy $_{gasoil\_res,\ y}$	11,824	***FF baseline*** $_{gasoil\ res,\ y}$	3,812			42.3						0.0733			
	BEy $_{wood\_res,\ y}$	0	***FF baseline*** $_{wood\ res,\ y}$	0				15.6						0		
	BEy $_{LPG\_res,\ y}$	111,924	***FF baseline*** $_{LPG\ res,\ y}$	37,658					47.6						0.0624	
	BEy $_{electricity\_res,\ y}$	***excluded from ER count***	***FF baseline*** $_{electricity\ res,\ y}$	***excluded from ER count***												
	BEy* total_*res, y	***123,748***														

Year	BEy tCO$_2$		$FF_{baseline\ i,y}$ (t)		NCV $_{FF,i}$ (GJ/t)						$EF_{FF,CO2,i}$ tCO$_2$/GJ					
					Coal	HFO	Gasoil	Wood	LPG	Electricity	Coal	HFO	Gasoil	Wood	LPG	Electricity
2019	$BEy_{coal\ res,y}$	0	$FF\ baseline_{coal\ res,y}$	0	12.6						0.0918					
	$BEy_{HFO\ res,y}$	0	$FF\ baseline_{HFO\ res,y}$	0		40						0.0766				
	$BEy_{gasoil\_res,y}$	12,031	$FF\ baseline_{gasoil\ res,y}$	3,879			42.3						0.0733			
	$BEy_{wood\_res,y}$	0	$FF\ baseline_{wood\ res,y}$	0				15.6						0		
	$BEy_{LPG\_res,y}$	113,880	$FF\ baseline_{LPG\ res,y}$	38,316					47.6						0.0624	
	$BEy_{electricity\_res,y}$	***excluded from ER count***	$FF\ baseline_{electricity\ res,y}$	***excluded from ER count***												
	BEy total_res, y	***125,911***														
2020	$BEy_{coal\ res,y}$	0	$FF\ baseline_{coal\ res,y}$	0	12.6						0.0918					
	$BEy_{HFO\ res,y}$	0	$FF\ baseline_{HFO\ res,y}$	0		40						0.0766				
	$BEy_{gasoil\_res,y}$	12,143	$FF\ baseline_{gasoil\ res,y}$	3,915			42.3						0.0733			
	$BEy_{wood\_res,y}$	0	$FF\ baseline_{wood\ res,y}$	0				15.6						0		
	$BEy_{LPG\_res,y}$	114,939	$FF\ baseline_{LPG\ res,y}$	38,672					47.6						0.0624	
	$BEy_{electricity\_res,y}$	***excluded from ER count***	$FF\ baseline_{electricity\ res,y}$	***excluded from ER count***												
	BEy total_res, y	***127,082***														
TOTAL BEy IND 2013-2020		***884,359***														
TOTAL BEy IND 2008-2020		***1,066,313***														

HFO = Heavy Fuel oil

3. Emissions due to switch from electricity to natural gas

The emissions EE_y from electricity replaced by natural gas are calculated as follows:

$EE_y = E_{R,y} * EF_{CO2,ELEC,Y}$

where:

$E_{R,y} = FF_{project\ i,\ y} * NCV_{NG,Y} * \varepsilon_{project,i} / \varepsilon_{baseline,i,y}$

where:

$EE_y =$	Emissions from the electricity generation for year y replaced by natural gas in tCO_{2e}
$E_{R,y} =$	Quantity of electricity replaced by natural gas in a respective sector without project implementation during the year y in MWh
$EF_{CO2,ELEC,y}=$	Carbon Emission Factor of the replaced electricity in tCO_{2e}/MWh
$FF_{project\ i,\ y} =$	quantity of natural gas combusted in the element process i during the year y in m^3
$NCV_{NG,Y} =$	Average net calorific value of the natural gas combusted during the year y in GJ/ m^3
$\varepsilon_{project,i} =$	Energy efficiency of the element process i if fired with natural gas
$\varepsilon_{baseline,i,y} =$	Energy efficiency of the element process i if fired with electricity

Industrial sector

Year	$EE_{total\_ind,\ y}$ (tCO_{2e})	$E_{R\ ind,\ y}$ (MWh)	$FF_{project\ i,\ y}$ (Sm3/y)	$NCV_{NG,Y}$ (GJ/Sm3)	$\varepsilon_{project,i}$ -	$\varepsilon_{baseline,i,y}$ -	$EF_{CO2,ELEC,y}$ (tCO2e/MWh)
2008	$EE_{electricity\_ind,\ y}$ 11,830	9,556	1,132,015	0.0331	0.9	0.98	1.238
2009	$EE_{electricity\_ind,\ y}$ 26,163	21,134	2,503,530	0.0331	0.9	0.98	1.238
2010	$EE_{electricity\_ind,\ y}$ 43,061	34,783	4,120,438	0.0331	0.9	0.98	1.238
2011	$EE_{electricity\_ind,\ y}$ 49,090	39,652	4,697,306	0.0331	0.9	0.98	1.238
2012	$EE_{electricity\_ind,\ y}$ 52,615	42,500	5,034,674	0.0331	0.9	0.98	1.238
Total (2008-2012)	***182,760***						
2013	$EE_{electricity\_ind,\ y}$ 53,577	43,277	5,126,648	0.0331	0.9	0.98	1.238
2014	$EE_{electricity\_ind,\ y}$ 53,577	43,277	5,126,648	0.0331	0.9	0.98	1.238
2015	$EE_{electricity\_ind,\ y}$ 53,577	43,277	5,126,648	0.0331	0.9	0.98	1.238
2016	$EE_{electricity\_ind,\ y}$ 53,577	43,277	5,126,648	0.0331	0.9	0.98	1.238
2017	$EE_{electricity\_ind,\ y}$ 53,577	43,277	5,126,648	0.0331	0.9	0.98	1.238
2018	$EE_{electricity\_ind,\ y}$ 53,577	43,277	5,126,648	0.0331	0.9	0.98	1.238
2019	$EE_{electricity\_ind,\ y}$ 53,577	43,277	5,126,648	0.0331	0.9	0.98	1.238
2020	$EE_{electricity\_ind,\ y}$ 53,577	43,277	5,126,648	0.0331	0.9	0.98	1.238
Total (2013-2020)	**428,612**						
TOTAL 2008-2020	**611,372**						

Public and administrative sector

Year	$EE_{total\_public,y}$ (tCO2e)		$E_{R\ public,y}$ (MWh)	$FF_{project\ i,y}$ (Sm3/y)	$NCV_{NG,Y}$ (GJ/Sm3) Natural gas	$\varepsilon_{project,i}$ - Natural gas	$\varepsilon_{baseline,i,y}$ - Electricity	$EF_{CO2,ELEC,y}$ (tCO2e/MWh)
2008	$EE_{electricity\_public,y}$	11,708	9,457	1,120,331	0.0331	0.9	0.98	1.238
2009	$EE_{electricity\_public,y}$	24,518	19,805	2,346,110	0.0331	0.9	0.98	1.238
2010	$EE_{electricity\_public,y}$	39,361	31,794	3,766,415	0.0331	0.9	0.98	1.238
2011	$EE_{electricity\_public,y}$	43,239	34,927	4,137,505	0.0331	0.9	0.98	1.238
2012	$EE_{electricity\_public,y}$	46,015	37,169	4,403,147	0.0331	0.9	0.98	1.238
Total (2008-2012)		***164,843***						
2013	$EE_{electricity\_public,y}$	46,759	37,770	4,474,263	0.0331	0.9	0.98	1.238
2014	$EE_{electricity\_public,y}$	46,759	37,770	4,474,263	0.0331	0.9	0.98	1.238
2015	$EE_{electricity\_public,y}$	46,759	37,770	4,474,263	0.0331	0.9	0.98	1.238
2016	$EE_{electricity\_public,y}$	46,759	37,770	4,474,263	0.0331	0.9	0.98	1.238
2017	$EE_{electricity\_public,y}$	46,759	37,770	4,474,263	0.0331	0.9	0.98	1.238
2018	$EE_{electricity\_public,y}$	46,759	37,770	4,474,263	0.0331	0.9	0.98	1.238
2019	$EE_{electricity\_public,y}$	46,759	37,770	4,474,263	0.0331	0.9	0.98	1.238
2020	$EE_{electricity\_public,y}$	46,759	37,770	4,474,263	0.0331	0.9	0.98	1.238
Total (2013-2020)		**374,070**						
TOTAL 2008-2020		**538,912**						

Residential sector

Year	$EE_{total\_res,y}$		$E_{R\ res\ y}$	$FF_{project\ i,\ y}$	$NCV_{NG,Y}$	$\varepsilon_{project,i}$	$\varepsilon_{baseline,i,y}$	$EF_{CO2,ELEC,y}$
	(tCO_{2e})		(MWh)	(Sm3/y)	(GJ/Sm3) Natural gas	- Natural gas	- Electricity	(tCO2e/MWh)
2008	$EE_{electricity\_resid.,\ y}$	9,624	7,774	920,884	0.0331	0.9	0.98	1.238
2009	$EE_{electricity\_resid.,\ y}$	27,708	22,381	2,651,322	0.0331	0.9	0.98	1.238
2010	$EE_{electricity\_resid.,\ y}$	46,355	37,443	4,435,635	0.0331	0.9	0.98	1.238
2011	$EE_{electricity\_resid.,\ y}$	65,442	52,861	6,261,990	0.0331	0.9	0.98	1.238
2012	$EE_{electricity\_resid.,\ y}$	85,613	69,154	8,192,152	0.0331	0.9	0.98	1.238
Total (2008-2012)		***234,471***						
2013	$EE_{electricity\_resid.,\ y}$	103,674	83,743	9,920,400	0.0331	0.9	0.98	1.238
2014	$EE_{electricity\_resid.,\ y}$	119,424	96,465	11,427,457	0.0331	0.9	0.98	1.238
2015	$EE_{electricity\_resid.,\ y}$	132,791	107,262	12,706,540	0.0331	0.9	0.98	1.238
2016	$EE_{electricity\_resid.,\ y}$	144,764	116,934	13,852,235	0.0331	0.9	0.98	1.238
2017	$EE_{electricity\_resid.,\ y}$	154,231	124,581	14,758,104	0.0331	0.9	0.98	1.238
2018	$EE_{electricity\_resid.,\ y}$	159,648	128,957	15,276,495	0.0331	0.9	0.98	1.238
2019	$EE_{electricity\_resid.,\ y}$	162,439	131,211	15,543,552	0.0331	0.9	0.98	1.238
2020	$EE_{electricity\_resid.,\ y}$	163,950	132,431	15,688,114	0.0331	0.9	0.98	1.238
Total (2013-2020)		**1,140,922**						
TOTAL 2008-2020		**1,375,663**						

Annex 3

MONITORING PLAN

In this Annex a description of metering system, reduction stations and gas odorization system is provided.
Moreover, fuel switch emission reduction factor (FSERF) values by sectors and the calculation of volume of natural gas at Standard conditions are shown.

Metering system and reduction stations
There are three types of gas meters used in the three sectors: membrane gas meters, rotating piston gas meters, turbine gas meters.
The membrane or diaphragm meters are used to measure medium and low flow, while the other two models are used to measure medium and large flow. The membrane gas meters are mainly used for the residential and small public users. The other two types normally are suitable for industrial uses or central heating systems where the burners have consumption fairly constant.
The membrane gas meters and the rotating piston gas meters are volumetric type, whereas the rotary-vane (turbine) meters are non-volumetric type.

The gas distribution network to the users in the towns will be at low pressure (0.5 bar), minimizing the risks caused by a medium pressure network.
Metering and reduction stations are of high quality standards. In particular, the following stations are foreseen:

- main reduction stations which receive the high pressure (55 or 16 bar) natural gas from Bulgargas network and where the quantity of natural gas provided by Bulgargas EAD is measured and reduced;
- first reduction stations which reduce gas pressure from the high pressure of National transport network (55 or 16 bar) down to medium pressure (5 bar);
- second reduction stations which reduce natural gas pressure from medium pressure to the pressure required by the end-users (0.5 bar).

The main equipment placed inside the above mentioned stations are:

- gas meters;
- electronic volume conversion devices;
- gas odorization devices;
- pressure reducers;
- filters, heat exchangers and boilers;

Gas odorization system
A gas odorization system is foreseen in the gas distribution network. Gas odorization involves addition of an odorant to gas to ensure characteristic odor to natural gas so that the presence of gas in air is readily detectable in case of leaks increasing the safety standards. The odorization system is “injection type” where odorant is injected, as liquid phase and in a metered quantity, directly into the natural gas.
The management of the gas odorization system involves weekly monitoring of odorization data through telemetry. All odorization systems will be connected to a remote control system manned 24 hours/day.
The control activities of the odorant in the gas network consist of:

- monthly check of the concentration of odorant in the natural gas (mg/m^3 of gas) carried out in the second reduction station, before gas is fed to the end-users, by means of an adequate calibrated instrument (Odor Handy);
- six-monthly gaschromatography analysis.

The calibration of the Odor Handy is done using for comparison a nitrogen cylinder with a known quantity of odorant; the calibration is carried out with an accuracy of 3.5% on a quantity of odorant of 40 mg/m^3, equal to 1.4 mg of odorant per m^3 of gas.
The check of odorant rate in the gas distribution network is carried out by means of portable gaschromatographies.

Fuel switch emission reduction factor (FSERF)
The FSERF is obtained by dividing the emissions reduction by the natural gas consumption. The FSERF quantifies the efficiency of the fuel switch from carbon fossil fuels to natural gas and it is measured in tCO_{2e}/ 1,000 Sm^3.
It is used for each sector to convert natural gas sales by sectors in emission reduction units. The fuel switch emission reduction factor includes the fuel switch effect and reduced energy consumption due to the increase of the efficiency of the combustion installations.
As shown in the table below, the FSERF is a constant value for each sector. In the industrial sector this factor is 0.66 tCO_2/1,000 Sm^3 which is higher than in the other two sectors (0.60 tCO_2/1,000 Sm^3 in the public sector and 0.14 tCO_2/1,000 Sm^3 in the residential sector). It means that in the industrial sector, every 1,000 Sm^3, the emission reductions due to the fuel switch are equal to 0.66 t CO_2, whereas in the public and residential sectors the emission reductions are respectively. 0.60 t $CO_2$and 0.14 t CO_2, every 1,000 Sm^3.

Table 3: Fuel switch emission reduction factor (FSERF)

Year	Natural gas consumption (1000 Sm^3)	Emission reductions (tCO_2)	FSERF (tCO_2/1000 Sm^3)
Industrial sector			
2008	14,010	9,299	0.66
2009	30,984	20,565	0.66
2010	50,996	33,846	0.66
2011	58,135	38,585	0.66
2012	62,310	41,356	0.66
2013	63,449	42,112	0.66
2014	63,449	42,112	0.66
2015	63,449	42,112	0.66
2016	63,449	42,112	0.66
2017	63,449	42,112	0.66
2018	63,449	42,112	0.66
2019	63,449	42,112	0.66
2020	63,449	42,112	0.66
Public and Administrative sector			
2008	5,441	3,289	0.60
2009	11,394	6,887	0.60
2010	18,292	11,057	0.60
2011	20,095	12,146	0.60
2012	21,385	12,926	0.60
2013	21,730	13,135	0.60
2014	21,730	13,135	0.60
2015	21,730	13,135	0.60
2016	21,730	13,135	0.60
2017	21,730	13,135	0.60
2018	21,730	13,135	0.60

Year	Natural gas consumption (1000 Sm^3)	Emission reductions (tCO_2)	FSERF (tCO_2/1000 Sm^3)
2019	21,730	13,135	0.60
2020	21,730	13,135	0.60
Residential sector			
2008	4,472	606	0.14
2009	12,877	1,745	0.14
2010	21,543	2,919	0.14
2011	30,413	4,121	0.14
2012	39,787	5,391	0.14
2013	48,181	6,529	0.14
2014	55,500	7,520	0.14
2015	61,712	8,362	0.14
2016	67,277	9,116	0.14
2017	71,676	9,712	0.14
2018	74,194	10,053	0.14
2019	75,491	10,229	0.14
2020	76,193	10,324	0.14

Calculation of volume of natural gas at Standard conditions

The standard conditions which are used for measuring volume of natural gas in Bulgaria are 293.15 K (20 °C) and 1.01325 bar.

There are two possible approaches for obtaining the volume under standard conditions:

- first approach: by using specialized devices called volume adjusters.
- second approach: by multiplying the volume read on the consumption meter counter by a fixed coefficient determined depending on the meteorological characteristics of the respective geographic region.

The volume of natural gas under standard conditions is calculated applying the following formula:

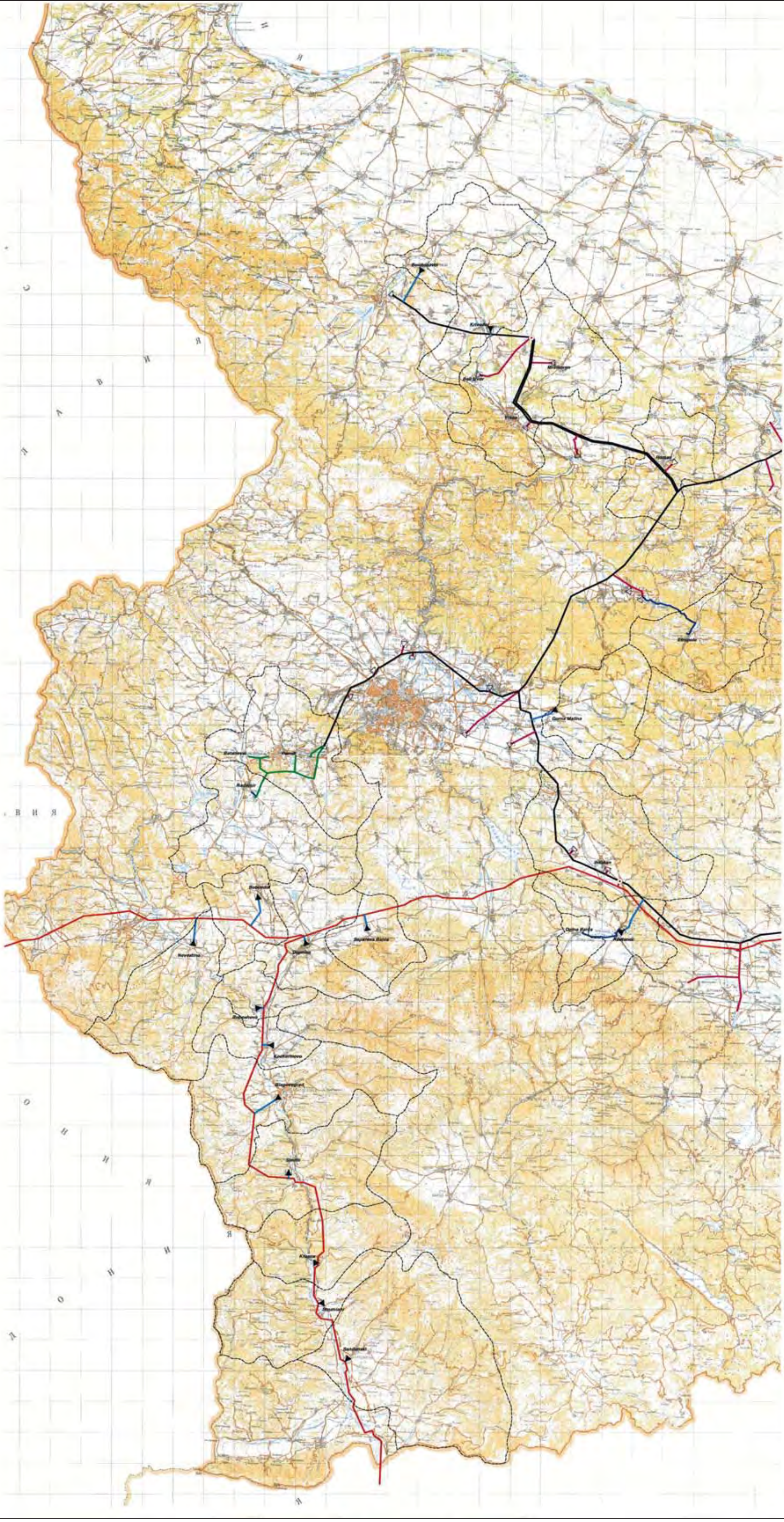
$$V_{st} = V_p \cdot (P/ P_{st}) \cdot (T_{st}/T) \cdot (Z_{st}/Z)$$

where:

V_{st} = Volume of gas under standard conditions, 293.15 K and 1.01325 bar (Sm^3)
V_p = Volume of gas measured by the gas meter (m^3)
P_{st} = Standard pressure (1.01325 bar)
P = Absolute pressure of gas in the measuring line (bar)
T_{st} = Standard temperature (for the Republic of Bulgaria: 293.15 K)
T = Absolute temperature of gas in the measuring line (K)
Z_{st} = Compressibility factor of gas under standard conditions
Z = Compressibility factor of gas in the measuring line

Annex 4

SCHEME OF GASIFICATION NETWORK IN THE ZAPAD REGION



MAIN GAS TRANSPORT NETWORK (PRESSURE <5.5 MPa)

GAS TRANSIT PIPELINE (PRESSURE <5.5 MPa)

EXISTING GAS PIPELINES BETWEEN BUILT-UP AREAS (PRESSURE < 5.5 MPa)

EXISTING GAS PIPELINES BETWEEN BUILT-UP AREAS (PRESSURE < 1 MPa)

PLANNED GAS PIPELINES BETWEEN BUILT-UP AREAS (PRESSURE: 0.4 MPa ÷1 MPa)

PLANNED GAS PIPELINES BETWEEN BUILT-UP AREAS (PRESSURE: 1 MPa ÷5.5 MPa)

PLANNED GAS REGULATION STATION

EXISTING GAS REGULATION STATION

EXISTING GAS COMPRESSION STATION

REPUBLIC OF BULGARIA

STATE ENERGY AND WATER REGULATION

Call for a license fot the activity
"distribution gas" on Zapad region

Joint-venture

ACEGAS-APS S.p.A

COSTRUZIONI DONDI S.p.A

West Territory

Scheme of the Existing
and Planned Gasification Network

Sacle 1:500000

Annex 5

LETTER OF SUPPORT

REPUBLIC OF BULGARIA

MINISTRY OF ENVIRONMENT AND WATER

February 2012
Sofia, Bulgaria

Rila Gas EAD
36 Alabin Str.
1301 Sofia
Bulgaria

LETTER OF SUPPORT

The Ministry of Environment and Water supports in principle the proposed project idea

Proposal number/date	48-00-110/30.01.2012
Title	Reduction of greenhouse gases by gasification in the Zapad Region of Bulgaria
Location	Zapad Region of Bulgaria
Supplier	Rila Gas EAD

and confirms that it falls within the scope of the Joint Implementation projects under Article 6 of the Kyoto Protocol to the United Nations Framework Convention on Climate Change.

The Ministry of Environment and Water will consider granting formal approval of the above mentioned Joint Implementation project according to the Bulgarian guidelines for approval of projects under Track 1/Track 2 of the Joint Implementation mechanism and after positive assessment of the project by the Bulgarian Joint Implementation Steering Committee.

Based on the fact that a part of the project activities may lead to direct or indirect double counting of emission reductions under the European Union Emission Trading Scheme, the Ministry of Environment and Water acknowledges hereby that free set-aside for avoiding double counting of emission reductions from JI projects is not available in the National Allocation Plan 2008 – 2012. Therefore, Emission Reduction Units could not be issued for the project emission reductions falling under the scope of double counting. After potential formal approval of the project the Ministry of Environment and Water will issue and transfer Emission Reduction Units only for verified emission reductions which do not lead to double counting under the European Union Emission Trading Scheme.

Evdokia Maneva
Deputy Minister of Environment and Water

Annex 6

ENVIRONMENT AND EMISSION STUDY IN THE ZAPAD REGION

RilaGas

Environment and Emission Study in Zapad Region

Summary

1. OUTPUT DATA

The present section discusses the reduction of the emissions from the polluters released during combustion, which reduction the gasification project in the present proposal will implement, by observing the following requirements and output data:

- Continuous distribution of the different types of fuels throughout the planning process;
- Prognosis for the sales of natural gas in section 1.1.3 Marketing research and methodology of the tendering documentation;
- Emission coefficients of the polluters for the various fuels of the U.S. Environmental Protection Agency (E.P.A), AP 42.

1.1. Polluters

The harmful substances released in the atmosphere as result of human activity generate various problems for the environment, some of which are considered particularly hazardous. The acid rains, the hothouse effect, the depletion of the stratospheric ozone layer, the aggravation o0f the quality of the air, problems that in particular cases can have direct impact on the daily life of millions of people have been subject to general discussion.

Usually, as the particularly hazardous components are considered, attention is paid to the following polluters of the atmosphere:

- Sulphur oxides (SOx);
- Nitric oxides (NO_x);
- Non-methane volatile organic compounds (COVNM);
- Methane (CH_4);
- Carbon monoxide (CO);
- Carbon dioxide (CO_2);
- Ammonia (NH_3);
- Nitrous oxide (N_2O);
- Dust or fine dust particles with diameter less that 10 μ (PM10);
- Heavy metals (As, Cd, Cr, Cu, Hg, Ni, Pb, Se and Zn);
- Organic Chlorine Compounds (dioxins, PCB, etc.).

These substances are divided into primary and secondary.

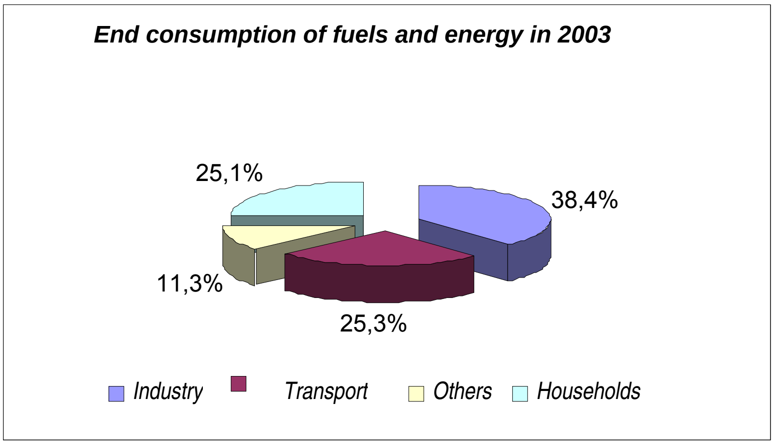
Primary polluters are those that are released directly into the atmosphere as result from atmospheric phenomena or from sources resulting from human activity, such as for instance SO_2, NO_X, NH_3, CO, CO_2.

Secondary polluters are those that are formed in the atmosphere through chemical or physical reactions of the primary polluters, such as for instance NO_2, SO_3, O_3, different acids, aldehydes, ketones.

1.2. Energy consumption and used fuels

The distribution of the end energy consumption in Bulgaria in 2003 is presented on Graph 1.[1] The principal consumers of energy are the industry, the transport and the households.

Graph 1



1.3. The Industry

In 2003 the industry in Bulgaria generates 26.3% of the Gross Domestic Product (GDP) of the country, while the Gross Value Added (GVA), created by the processing industry, is around 58% of the GVA of the industry. It is the biggest consumer of primary energy sources, fuels and energy, consuming 38.4% of the end energy consumption in the country. The biggest energy consumers in

[1] http://www.seea.government.bg/documents/National_EE_Programme-last17.06.doc

the sector are: ferrous metallurgy, the chemical industry, the production of non-metal mineral raw materials and the food and industry.

In 2003 the sector industry has used 3521 ktoe, which comprises 38.4% of the EEC (End Energy Consumption) of the country. Within the framework of the sector the most serious energy consumer is the industrial production which has a 95% share of the EEC of the industry.
On Table 1 is presented the structure of the end energy consumption by types of fuels and sectors. In sector industry the biggest share is that of the liquid fuels, followed by electric power, natural gas and coal.

1.4. The Services

The end consumption in the sector of the services in 2002 is 742 ktoe, in 2001 - 770 ktoe, and in 2000 - 650 ktoe. Moreover the Gross Value Added of the sector of the services in the GDP increased proportionally to the consumed energy, i. e. the energy intensiveness of the sector does not change significantly.
The sector is oriented to consumption of fuels and energy with high end efficiency regardless of their price.
Since 1998 the added value of the services in Bulgaria marks an annual growth of 5%. This growth corresponds to the increased energy consumption in the sector and especially of the increase of the consumption of electric power consumption (6.8% per annum), whose share in the general energy consumption in 2003 is the biggest (67%).

1.5. The Households

The energy consumption in the households reflects the consumption of fuels and energy for meeting the household needs of the population and is directly dependent on the way of life of the people and their living standard. The share of the fuels and energy used by the household consumers in the country in 2003 is around 24.7% of the end energy consumption.
The end energy consumption in the household sector during the period 1997 – 2003 oscillates within the boundaries of 2000 ktoe in 2001 to 2304 ktoe in 2003. Before the end of 1996 the use of liquid fuels abruptly was reduced resulting from the liberalization of their prices. After 1991 due to its low price, the consumption of firewood rapidly increased.
The highest share in the energy consumption of the household sector belongs to electric power. During the period 1997 – 2003 it oscillates within the boundaries of 38.1% to 34.7%, whereas in

the European countries it is 10 - 12%. During the period 1997-2003 the share of the firewood increased from 8.1% to 26.3 % and to date it significantly surpasses the share of the heat energy (20.5%).

The specific energy consumption per house in Bulgaria is around 0.83 toe/house, whereas in the European Union countries it is 1.7 toe/house (2000), i.e. around 2 times higher. Following a period of decrease in 2001 the specific energy consumption started growing by around 6.7% per annum, i.e. much faster than the growth of the GDP.

1.6. End energy consumption by types of fuels

The end energy consumption by types of fuel includes the use of fossil fuels (coal and firewood), liquid fuel (oil products), natural gas, electric power and heat energy. The use of fossil fuels includes low quality brown (bituminous) coal and lignite coal local production[2], characterized with low caloricity (up to 4300 kcal/kg) and high contents of sulphur (up to 3%).
From the liquid fuels mazut and industrial naphtha are widely used in the industry. Mazut is heavy oil product with high contents of sulphur (up to 3.5%), and its burning is accompanied with the release of large quantities of dust and other harmful emissions.

Table 1

End consumption by types of fuel in Bulgaria in 2003 [3]						
	Industry		Public organizations etc.		Households	
	toe	%	toe	%	toe	%
Liquid fuels	853	24.2%	303	29.22%	29	1.26%
Natural gas	766	21.8%	45	4.34%	3	0.13%
Coal	726	20.6%	8	0.77%	393	17.06%
Electric power	791	22.5%	527	50.82%	800	34.72%
Heat energy	302	8.6%	138	13.31%	472	20.49%
Firewood	83	2.4%	16	1.54%	607	26.35%
Total	3521	100.0%	1037	100.00%	2304	100.00%

[2] http://nfp-bg.eionet.eu.int/ncesd/bul/UNFCCC/2003/an2.doc

[3] *Statistical Yearbook 2004*

2. EMISSION COEFFICIENTS

The presented emission coefficients of the principal polluters for the different fuels have been determined by AP 42, *Fifth Edition Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources*, *E.P.A. Environmental Protection Agency, DOE, USA*.

Natural gas

Table 2

Polluter	Coefficient of separation (lb/10^6 ft^3)	AP-42 table	Date of issuance
CO	40	1.4-1	07/98
NO_x	94	1.4-1	07/98
SO_2	0.6	1.4-2	07/98
VOC	5.5	1.4-2	07/98
PM10	1.9	1.4-2	07/98
PM2.5	1.9	1.4-2	07/98
PM Condensable	5.7	1.4-2	07/98

Industrial naphtha

Table 3

Polluter	Coefficient of separation (lb/10^3 gallons)	AP-42 table	Date of issuance
CO	4.8	1.3-1	09/98
NOx	17.4	1.3-1	09/98
Sox	41.1	1.3-1	09/98
VOC	0.7	1.3-3	09/98
PM10	0.4	1.3-1	09/98
PM2.5	0.83	1.3-7	09/98
PM Condensable	1.3	1.3-2	09/98

Mazut

Table 4

Polluter	Coefficient of separation (lb/10^3 gallons)	AP-42 table	Date of issuance
CO	5	1.3-1	09/98
NOx	47	1.3-1	09/98
SOx	157S	1.3-1	09/98
VOC	0.7	1.3-3	09/98
PM10	0.4	1.3-1	09/98
PM2.5	0.83	1.3-7	09/98
PM Condensable	1.5	1.3-2	09/98

Coal

Table 5

Polluter	Coefficient of separation (lb/ton)	AP-42 table	Date of issuance
CO	275	1.1-3	09/98
NOx	3.0	1.2-1	10/96
Sox	39S	1.2-1	10/96
VOC	10	1.1-19	09/98
PM10	10.0	1.2-3	10/96
PM2.5	0.6A	1.2-4	10/96
PM Condensable	0.08A	1.2-3	10/96

Firewood

Table 6

Polluter	Coefficient of separation (g/kg)	AP-42 table	Date of issuance
CO	126.3	1.9-1	10/96
NOx	1.3	1.9-1	10/96
Sox	0.2	1.9-1	10/96
VOC	114.5	1.9-1	10/96
PM10	17.3	1.9-1	10/96
PM2.5			
PM Condensable			

3. CURRENT STATUS

3.1 Climate

Territory “Zapad” is located in the Western part of republic of Bulgaria. The Northern part of territory “Zapad” includes part of the Western Balkan and the PreBalkan, Ikhtiman Sredna Gora, Vitosha, Lyulin and Lozen Mount. In the Southwestern part of territory “Zapad” are located part of the Osogovo-Belasitsa Mountain group, Rila and Pirin, Kyustendil Hollow, Petrich-Sandanski Plain, the valley of River Struma and others. Territory “Zapad” is characterized by its heavily broken ground relief comprising a mosaic of mountains, gorges, hollows and river valleys.

In the Northern part of territory “Zapad” the climate is moderately continental with average annual temperature of the air around 11°C. The absolute maximum temperature measured on the territory is plus 40.2°C (June 2000), and the absolute minimal temperature was minus 16.6°C (December 1999). The period of the negative average daily temperatures is around 70 days and the snow cover during the winter season holds around 2.5 months. In the Northern part of territory “Zapad” spring is cool and fresh and autumn is warm.

In the Southwestern part of territory “Zapad” the climatic conditions are varied with significant temperature range. Rila and Osogovo mountains influence the climate in the valley of River Struma, Kyustendil Hollow and Petrich-Sandanski Plain. In this region Mediterranean influence is observed and the climate transitions into continental-Mediterranean. The Southwestern part of the territory is traversed from north to south by River Struma, and in the Samokov Plain runs River Iskar. The rivers are characterized with a rain-snow pattern and maximum flow during the early spring. This part of territory “Zapad” is characterized by a mild winter, early spring and hot summer. The average annual temperature in the Southwestern part of territory “Zapad” is around 12°C, and in the Sandanski-Petrich Plain the highest average annual temperature in Bulgaria of 13.9°C has been measured. The period with negative average daily temperatures is 50-60 days and the average January temperature in the areas with transitional continental climate is plus 1°C, while in the Sandanski-Petrich Plain it is above plus 2°C.

The climatic and geographical conditions exercise substantial influence on the different components of the environment. The destruction of the eco systems, the reduction of the supply of fresh water and of the productivity of the arable land are part of the consequences from the changes of the climate which leads to heavy economic and social consequences as well as to unfavourable influence on the human health in the form of heavy chronicle disorders, allergies etc.

3.2. Condition of the atmospheric air

The distribution of the principal polluters of the environment by sectors follows the distribution of the end energy consumption. The energy sector in Bulgaria, and more specifically the thermal electric power stations using lignite coal is principal source of emissions of sulphur dioxide, carbon dioxide, dioxins and furans and relatively significant quantity of nitric oxides.[4] In 2002 89% of the total quality of sulphur dioxide in the country, 30% of the total emissions of nitric dioxide and around 40% of the dust emissions were released in this sector.

The burner installations in the households and in transport are the principal emitters of harmful emissions after energy production. The harmful emissions from the burner installations in the households exert significant influence on the quality of the atmospheric air because of the use of coal, briquettes and firewood and their burning in low efficiency burner installations. The dispersion of the atmospheric polluters emitted from the household sector is minimal and under the specific winter conditions long periods with accumulation result from it, leading to higher ground level concentrations.

[4] http://nfp-bg.eionet.eu.int/ncesd/bul/UNFCCC/2003/an2.doc

The pollution of the atmospheric air by stationary and mobile sources exerts direct negative influence on human health, vegetation, soil and waters and affects not only the country where pollution is taking place but other countries as well.

The quality of the atmospheric air on the territory of Republic of Bulgaria is assessed on the basis of the data from the National network for control of the atmospheric air and from centers of the Ministry of Health. The principal components released during the burning of the used energy sources polluting the environment and controlled are dust, nitric oxides, sulphur oxides, carbon oxides.

On territory "Zapad" are observed traditionally high concentrations of dust which is typical for all of Bulgaria as well. In 2002 in Pernik and Montana were measured some of the highest average annual and average day and night concentrations of fine dust particles (FDP 10) and highest number of exceeding values of the average day and night permissible concentration limits (75 $\mu g/m^3$).

In 2002 on territory "Zapad" no exceeding values of the average day and night permissible concentration limits of nitric dioxide were registered. On the territory of the Regional Inspectorate of Environment and Waters in Montana was registered maximum single (measurement units) concentration of nitric dioxide close to the permissible concentration limits – PCL m. u. /200 $\mu g/m^3$/.

No pollution of the atmospheric air on territory "Zapad" with sulphur dioxide was registered in 2002. No exceeding values of the permissible concentration limits (350 $\mu g/m^3$) were observed. During the winter months the total concentration of sulphur dioxide in the country has increased which results from the more intensive consumption of heat energy and electric power by the population during this period. [5]

4. CHANGE OF THE EMISSION AFTER THE GASIFOICATION

The reduction of the harmful emissions and the improvement of the quality of the atmospheric air will be realized in the process of gasification with the construction of the gas distribution network and the substitution of the used fuels with natural gas. With the gasification, reduction of the

[5] Annual state of the Environment report 2002, Republic of Bulgaria, Council of Ministers, Executive environment agency

harmful influence of the energy consumption on the environment is achieved as a result of the use of natural gas and the reduction of the total quantity of energy used, due to increase of the energy efficiency of the burner installations. Gasification creates opportunities for the introduction of modern technologies in the processes of energy production.

In *Table 7* the harmful emissions released during the burning of fossil and liquid fuels are compared to their equivalent quantity natural gas. As a result of the substitution of the fossil and liquid fuels the emissions of acid oxides and dust will sharply be reduced.

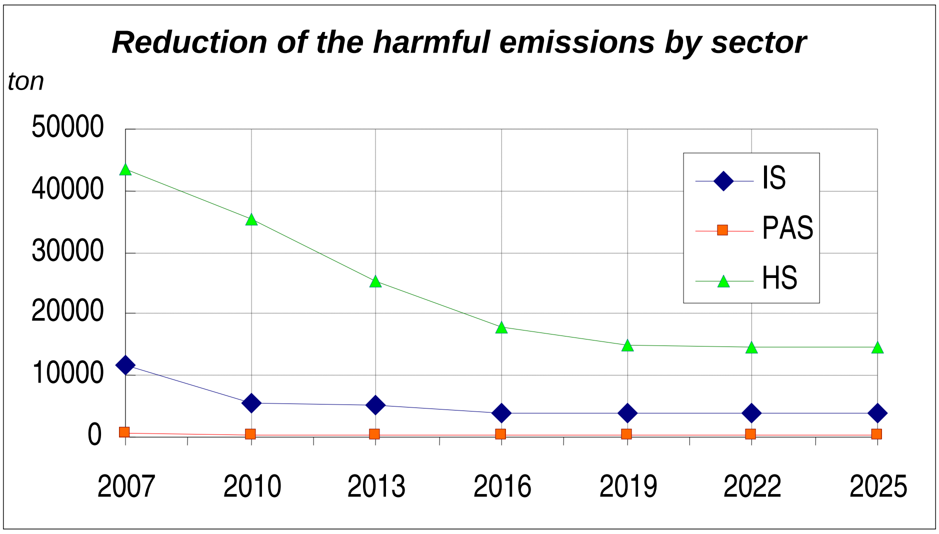
Table 7

Comparative characteristics of the harmful emissions of the fossil and liquid fuels with the natural gas				
Polluter	Natural gas	Firewood	Coal	Mazut
CO2	1	1.681	1.019	1.386
SO2	1	42,826.0	7,484,874	1,740,945
Nox	1	230,180.3	221,141.8	142,137
CO	1	2,875.7	43.3	154
PM10	1	68,106.0	125,567.2	10,864
TOC	1	3,667.8	73.4	629

During the burning of the coal and mazut heavy metals, dioxins and furans, as well as many other harmful substances are released, which when they enter the soil and the water lead to durable contamination around the large burner installations.

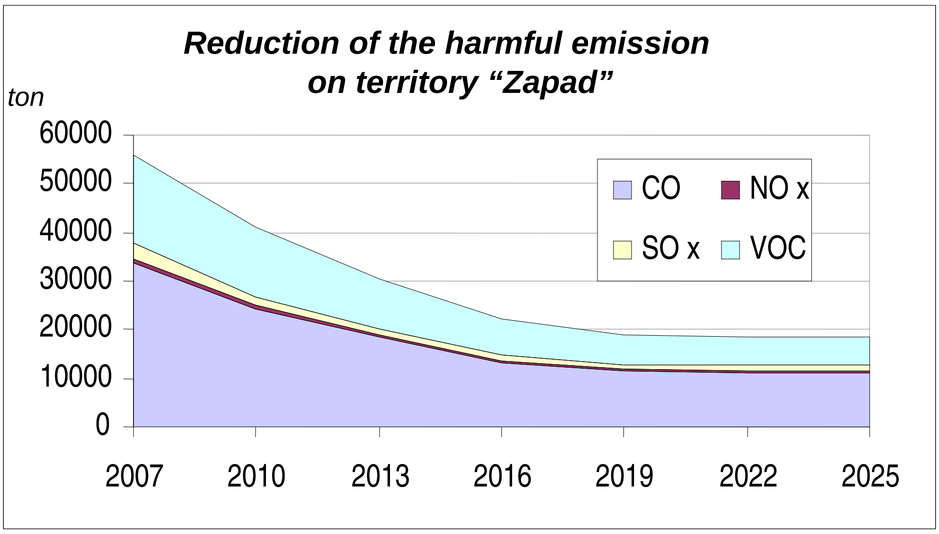
Following the substitution of the fossil and liquid fuels the emissions in the household sector will be most significantly reduced. This is due to the larger quantity substituted fossil fuels in the household sector and to the significantly increased energy effectiveness of the burner installations in the households from 65% to 90%. *(Graph 2)*

Graph 2



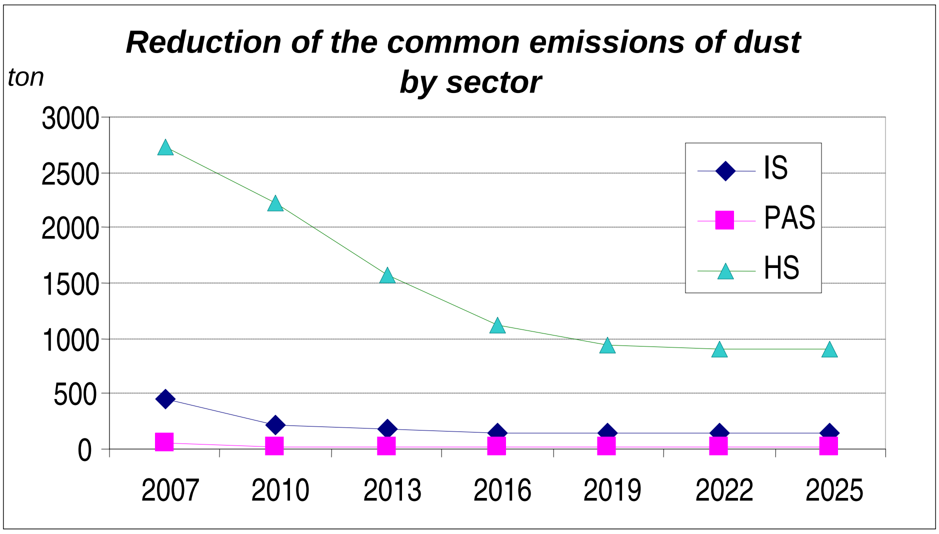
The change of the emissions by types in the process of gasification follows the increase of the natural gas by years on the territory "Zapad". During the initial 10 years the reduction of the acid oxides and the volatile organic compounds (COV) takes place slowlier (Graf 3). The greatest reduction of the carbon oxide and the VOC corresponds to the greatest emissions in the household sector caused by the incomplete burning in the household burner installations.

Graph 3



Bearing in mind the characteristic for Bulgaria high contents of solid dust particles (dust) the reduction of the emissions of dust is of significant importance when assessing the impact of gasification on the environment. The total quantity of dust in the process of gasification is reduced proportionally to the other emissions and is biggest in the household sector (*Graph 4)*

Graph 4



Since the energy sector is the biggest emitter of harmful emissions, the substitution of the electric power with natural gas will bring about reduction of the total emissions of harmful substances in Bulgaria.

The substitution of the fossil and liquid fuels and the electric power leads to reductions of the emissions of hothouse gases. In its final stage the gasification of territory “Zapad” will achieve reduction of the hothouse gases by more than 300 000 tons annually. This quantity does not include the reductions resulting from the substitution of electric power and the losses during transportation and distribution.

Annex 7

BASELINE CARBON EMISSION FACTOR OF BULGARIAN ELECTRICITY AND HEAT POWER SYSTEM

Baseline Carbon Emission Factor of
Bulgarian Electricity and Heat Power System

		Unit	2000	2001	2002	2003	2004		
1.	**Total system power generation**	GWh	**41 805**	**44 785**	**41 943**	**41 990**	**43 621**		
2.	**Total system heat generation**	$MW_{th}h$	**14 398 244**	**17 092 947**	**17 104 183**	**18 945 487**	**15 622 107**		
3.	**Total CO2 emissions of power generation**	kt/a	**20 686,07**	**24 186,09**	**21 130,37**	**23 502,96**	**26 141,93**		
4.	**Total CO2 emissions of energy transformation**	kt/a	**25 364,83**	**29 868,93**	**27 206,40**	**29 968,99**	**31 566,24**		
	Baseline Emission Factor - BEF								
	Fossil Fuels								
1.	**Dispatch Data_OM_EF**	tonne/MWh	1,215	1,287	1,214	1,226	1,199		
2.	**Dispatch Data Adjusted_OM_EF**	tonne/MWh	1,159	1,222	1,150	1,160	1,138		
3.	**Average Dispatch Data_OM_EF**	tonne/MWh	1,269	1,307	1,231	1,237	1,239		
	HPP included								
1.	**Dispatch Data_OM_EF**	tonne/MWh	1,144	1,184	1,106	1,160	1,165		
2.	**Dispatch Data Adjusted_OM_EF**	tonne/MWh	1,065	1,106	1,032	1,067	1,078		
3.	**Average Dispatch Data_OM_EF**	tonne/MWh	1,101	1,149	1,040	1,073	1,108		
	Fossil Fuels								
1.	**Dispatch Data_OM_EF**	kg/GJ	106,38	109,57	110,86	111,24	110,03		
2.	**Dispatch Data Adjusted_OM_EF**	kg/GJ	106,93	109,05	110,68	111,09	109,91		
3.	**Average Dispatch Data_OM_EF**	kg/GJ	109,43	108,79	109,00	109,47	110,63		
	Forecast								
	Minimum demand	Unit	2006	2007	2008	2009	2010	2011	2012
1.	**Total system power generation**	GWh	45 051	43 115	44 156	47 490	48 212	51 139	52 291
2.	**Total system heat generation**	$MW_{th}h$	17 875 519	18 057 503	18 320 175	18 746 936	19 028 565	19 744 974	19 358 651
3.	**Total CO2 emissions of power generation**	kt/a	28 035,37	31 810,38	31 245,76	33 538,31	33 547,47	33 863,20	31 248,73
4.	**Total CO2 emissions of energy transformation**	kt/a	34 447,38	38 304,71	37 832,72	40 154,36	40 358,39	40 560,20	37 758,36
	Baseline Emission Factor - BEF								
	Fossil Fuels								
1.	**Dispatch Data_OM_EF**	tonne/MWh	1,215	1,158	1,144	1,022	0,984	0,963	0,953
2.	**Dispatch Data Adjusted_OM_EF**	tonne/MWh	1,154	1,100	1,078	0,956	0,917	0,902	0,899
3.	**Average Dispatch Data_OM_EF**	tonne/MWh	1,243	1,190	1,146	1,026	0,986	0,974	0,983
	HPP included								
1.	**Dispatch Data_OM_EF**	tonne/MWh	1,176	1,175	1,110	0,995	0,959	0,940	0,918
2.	**Dispatch Data Adjusted_OM_EF**	tonne/MWh	1,111	1,102	1,017	0,894	0,858	0,849	0,838
3.	**Average Dispatch Data_OM_EF**	tonne/MWh	1,138	1,153	1,057	0,947	0,909	0,898	0,889
	Fossil Fuels								
1.	**Dispatch Data_OM_EF**	kg/GJ	111,997	106,693	106,484	100,340	97,288	95,088	96,152
2.	**Dispatch Data Adjusted_OM_EF**	kg/GJ	111,976	106,621	106,402	100,566	97,871	95,946	96,570
3.	**Average Dispatch Data_OM_EF**	kg/GJ	111,622	106,175	106,640	100,646	98,217	96,578	97,026
	Forecast								
	Maximum demand	Unit	2006	2007	2008	2009	2010	2011	2012
1.	**Total system power generation**	GWh	46 739	43 572	46 588	48 351	49 455	51 368	53 194
2.	**Total system heat generation**	$MW_{th}h$	20 360 486	19 909 333	20 240 498	21 206 857	22 170 354	23 026 991	23 407 576
3.	**Total CO2 emissions of power generation**	kt/a	27 152,04	31 508,75	32 821,32	33 044,62	33 387,00	32 807,31	30 531,04
4.	**Total CO2 emissions of energy transformation**	kt/a	34 405,23	38 713,17	40 181,87	40 770,13	41 342,14	40 706,37	38 615,88
	Baseline Emission Factor - BEF								
	Fossil Fuels								
1.	**Dispatch Data_OM_EF**	tCO2/MWh	1,204	1,215	1,124	1,014	0,973	0,947	0,884
2.	**Dispatch Data Adjusted_OM_EF**	tCO2/MWh	1,143	1,156	1,059	0,947	0,908	0,884	0,833
3.	**Average Dispatch Data_OM_EF**	tCO2/MWh	1,233	1,252	1,127	1,018	0,977	0,953	0,917
	HPP included								
1.	**Dispatch Data_OM_EF**	tCO2/MWh	1,158	1,168	1,101	0,990	0,947	0,928	0,865
2.	**Dispatch Data Adjusted_OM_EF**	tCO2/MWh	1,091	1,095	1,006	0,888	0,850	0,834	0,791
3.	**Average Dispatch Data_OM_EF**	tCO2/MWh	1,118	1,144	1,052	0,940	0,899	0,879	0,840
	Fossil Fuels								
1.	**Dispatch Data_OM_EF**	kg/GJ	109,651	111,991	105,315	100,011	95,929	94,604	93,043
2.	**Dispatch Data Adjusted_OM_EF**	kg/GJ	109,571	111,876	105,263	100,226	96,498	95,130	93,524
3.	**Average Dispatch Data_OM_EF**	kg/GJ	109,126	111,908	105,550	100,273	96,821	95,676	94,056