TSU Internship Report
IPCC NGGIP / IGES

National GHG Emission Factors in Former Soviet Union Countries

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LIST OF ACRONYMS, ABBREVIATIONS, AND UNITS

CORINAIR	CO-oRdination d'INformation Environnementale (AIR), Work programme aimed at gathering and organising information on air pollutant emissions in the European Union
EF	Carbon Emission Factor (also specific carbon content, t C/TJ)
GHG	Greenhouse Gas
FSU	Former Soviet Union
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
KazNIIMOSK	Kazakh Scientific Research Institute for the Monitoring of Environment and Climate
NCV	Net Calorific Value of Fuel (TJ or GJ per natural unit)
CEF	Carbon Emission Factor, tC/TJ
NGGIP	National Greenhouse Gas Inventories Program
OECD	Organization for Economic Cooperation and Development
RAO UESR	*Russian Joint Stock Company* Unified Energy System of Russia
TPP	Thermal Power Plant
UNFCCC	United Nations Framework Convention on Climate Change
US AID	United States Agency for International Development
US EPA	United States Environmental Protection Agency
USSR	The Union of Soviet Socialist Republics

Chemical Symbols

CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
N_2O	Nitrous oxide
NMVOC	non-methane volatile organic compounds
NO_x	nitrogen oxides
SO_2	sulphur dioxide

Units

Gg	gigagram
mln m^3	million cubic meter
ths t	thousand tonne
TJ	terajoule
GJ	gigajoule
tce	ton of coal equivalent
toe	ton of oil equivalent
mln t	million metric tonne

1 INTRODUCTION

Russia, Ukraine, and Kazakhstan are the three largest republics of the Former Soviet Union and the three biggest emitters of greenhouse gases. They are also the only countries of the Former Soviet Union that either currently are in Annex B of the Kyoto Protocol, like Ukraine and Russia, or expressed their desire to join Annex B and be bound by emission limitations, like Kazakhstan. Precise estimation of the emissions of these three countries is therefore an important issue, which has been the focus of attention of local researchers and other Annex I governments.

With the help of many donor agencies and national governments, a significant level of activity related to the development of greenhouse gas inventories has been carried out in Russia, Ukraine, and Kazakhstan starting as early as 1996. While earlier activities have been mostly reflected in 1996 Revised IPCC Guidelines and 2000 Good Practice Guidance, more recent activities have not been systematically presented to IPCC NGGIP and therefore has not been made known to wider international inventory community.

The aim of this report is to provide an overview of the inventory-related research carried out in the Former Soviet Union countries over the last 5-6 years, and highlight achievement in adopting IPCC methodologies, improving inventory quality, and establishing local emission factors. We also hope that some of the information presented here can serve as input to the IPCC Emission Factor Database and consequently the revision of the 1996 Revised IPCC Guidelines, potentially also serving as a point of reference for the improvement of the national inventories in these and other countries in the region and beyond.

The focus of this research is on Russia, Ukraine, and Kazakhstan, since these are the countries of the Former Soviet Union countries where most of the independent inventory work has been carried out to date. The scope of the paper is mostly limited to major key source categories, such as the IPCC energy sector, but other sectors are considered as well to highlight the progress that has been achieved there. Such limitation of both geographic and sectoral scope is explained by the interest of researchers and funders to large greenhouse gas sources and contributors, as well as the desire to improve the quality of the inventories cost-efficiently through addressing the most significant of those sources.

The paper is divided into 5 main sections. It begins with an introduction about the institutional background on inventory development and inventory-related research in Russia, Ukraine, and Kazakhstan. We then examine specific emission factors that were developed by local specialists for the purposes of inventory development on the national and sectoral levels. Four major areas are considered: CO_2 emissions from stationary combustion, mobile combustion, CO_2 emissions from coke gas combustion, fugitive emissions, and CO_2 emissions from cement manufacture.

2 NATIONAL CIRCUMSTANCES IN RUSSIA, UKRAINE, AND KAZAKHSTAN

2.1 General information about the region and its GHG emissions

Russia, Ukraine, and Kazakhstan are the three largest republics of the Former Soviet Union, accounting for 90% of its territory and population, as well as for the majority of its industrial output. After significant industrial decline following the break-up of the USSR, the economies of all three countries became dominated by exports of natural and mineral resources. In Russia alone, oil, natural gas, metals, and timber account for more than 80% of exports. Kazakhstan's economy is similarly heavily based on the extraction and processing of natural resources, mostly oil and gas, as well as other minerals and metals. In addition Kazakhstan is a large agricultural producer, specializing in livestock and grain. Likewise, Ukrainian economy is also export-oriented, with metals and agricultural products (grains) accounting for the majority of exports.

Table 2.1 Key statistical information on Russia, Ukraine, and Kazakhstan

Country Name	Population*	Total area, sq km	Industrial growth,% *	Per capita GDP, $US*
Russia	144,978,573	17,075,200	5.2	8,300
Ukraine	48,396,470	603,700	14.2	4,200
Kazakhstan	16,741,519	2,717,300	11.4	5,900

**2002 data, World Resources Institute*

Russia, Ukraine, and Kazakhstan were collectively responsible for 4,230 $MtCO_2$ emissions in 1990. Although their emissions drastically reduced since the fall of the Soviet Union in 1991, Ukraine and Russia, the two current Annex I countries, still accounted for about 37% of Annex I emissions in 1998, the last year when UNFCCC data is available for both of the countries.

In its base year, 1990, Ukraine emitted 919 $MtCO_2$, and in the latest year available, 1998, Ukraine's emissions were approximately half of that at 455 $MtCO_2$. [1] In the period between 1990 and 1998, six key source categories of GHG emissions were identified for Ukraine. [2] They are: CO_2 emissions from fuel combustion, fugitive emissions from natural gas and oil, fugitive emissions from coal mining and handling, CH_4 emissions from livestock enteric fermentation, CO_2 emissions from mineral products, and CH_4 emissions from solid waste disposal. The first three categories accounted for approximately 90% of the total throughout the indicated period, with CO2 emissions from fuel combustion being responsible for 73 and 68 percent in 1990 and 1998 respectively. Fugitive emissions from natural gas and oil and fugitive emissions from coal mining and handling made up 14 and 6 percent respectively in 1998 and 8 and 4 percent in 1990.

Russian GHG emissions in 1990 were the second largest among Annex I countries after the US, at about 3,040 $MtCO_2$. Since then Russian GHG emissions have fallen sharply, totaling 1,877 $MtCO_2$ in 1999. Similarly to Ukraine, in Russia, combustion of primary and secondary fossil fuels accounted for 77.6% of all GHG emissions in 1999. Main sources of methane emissions in Russia in 1999 were transportation and distribution of oil and gas (57%), waste (13%) and coal mining (10%). Overall, methane made up about 15% of all GHG emissions in Russia in 1999. [3]

Kazakhstan does not have a formal base year yet as it has not negotiated a target. However, it is expected that 1992 will be accepted as a base year. In 1992 the total emission of all greenhouse gases in Kazakhstan amounted over 372.2 Mt of CO_2-equivalent (361.8 MtCO_2 discounting sequestration by forests). The most important source of the GHG emissions in Kazakhstan is the energy sector, accounting for 315.3 MtCO_2 or 84.7% of the total CO_2-equivalent emissions. In the energy category, emissions from the fuel combustion amount to about 93% and about 7% are made up by fugitive emissions generated at the fuel mining, transporting and processing. Emissions from the industrial processes category (emissions not related to the fuel combustion in the industry) made up 4.6% of the total GHG emissions. In 2001, the latest year available for Kazakhstan, total GHG emissions were at the level of 154.7 Mt CO_2, of which 122.5 (or 79.2%) were contributed by the energy sector category. The second and third largest GHG sources in CO2 equivalent were agriculture (10.3%) and industrial processes (8.4%).[4]

2.2 Institutional Background and Previous Related Activities

Russia, Ukraine, and Kazakhstan all have different institutional backgrounds with regards to the compilation of the greenhouse gas inventories.

In **Russia**, the federal agency formally responsible for development of Russian National Communications and the compilation of the national inventories is the Russian Federal Service for Hydrometeorology and Environmental Monitoring (Roshydromet). Roshydromet periodically compiles national greenhouse gas emission data based on the reference approach and has most recently (2002) submitted Third National Communication of the Russian Federation to the UNFCCC Secretariat.

In addition, several regional and sectoral inventories have been developed:

- 7 Russian regions have compiled their greenhouse gas inventories with support of the Moscow-based Center for Energy Efficiency (CENEf). Although a small percentage of the overall number of all Russian region, they were chosen on the basis of their representativeness, potential weight in GHG emissions, and comparative size.
- RAO «Unified Energy System of Russia», the largest energy producer in Russia, carries out annual inventories for its big heat and power plants.
- Gazprom, Russian gas monopolist, which extracts more than 90% of total gas production in the country, has carried out activities to estimate its corporate fugitive emissions.
- The inventory of greenhouse gas emissions from coal mining and handling in Russia was carried out by the Russian Methane Centre (Kemerovo).
- The International Forestry Institute (Moscow) has undertaken an analysis of carbon emission and sinks in the Russian forest sector based on the official forest inventories data and its own specific studies.

In **Ukraine**, there is currently no single agency responsible for the development of the national inventory. Although general support for the inventory preparation was designated to the Institute of Energy of the Ukrainian Academy of Sciences, actual annual compilation of the inventories suffered from lack of budgetary support from the government.

Ukraine's First National Communication to UNFCCC was completed in 1999 with support of the Ministry of Environment of Ukraine and included annual inventories for the period of 1991-1998. The 1990 Inventory was prepared under the U.S. Country Study Program. Experts from six organizations were involved in this study: the Institute of Energy of the National Academy of

Sciences of Ukraine (energy), the State Committee on Forestry (land-use and forestry), the Ministry of Environment and Natural Resources (general coordination, waste), the State Committee on Statistics (activity data), the National Academy of Agriculture (agriculture), and the Agency for Rational Energy Use and Ecology (compilation of results and preparation of the final report).

Since 2000, no coordinated effort has been carried out on the national level. However, with the help of various donor agencies, individual inventory initiatives have been carried out:

- Partnership of Economic and Environmental Reform (PEER) developed a bottom-up inventory of CH_4 emissions of all mines in Ukraine was developed (1999-2001).
- Canada-Ukraine Environmental Cooperation Program (CUECP, 1999-2003) analyzed GHG emissions from coke combustion production at a pilot facility and compiled the inventory for whole energy sector .
- Climate Change Initiative (CCI) developed inventories for key sources such as energy and aluminium industry.
- Agency for Rational Energy Use and Ecology (ARENA-ECO) compiled greenhouse gas inventories for district heating sector and cement production.
- Center for Clean Air Policy (CCAP) developed pilot inventories for two Ukrainian regions.

Only two of these initiatives (power sector inventory by CCI and coal-bed methane inventories by PEER) undertook development of the national emission factors.

In **Kazakhstan**, the agency responsible for the development of the national inventories is Kazakh Scientific Research Institute for the Monitoring of Environment and Climate (KazNIIMOSK). With the support from the government of Kazakhstan, KazNIIMOSK has been compiling the national inventories of greenhouse gases (GHG) on an annual basis since 1999. Currently the inventory exists for the year 1990, 1992, 1994, 1999-2001. In addition, KazNIIMOSK undertook a number of in-depth studies of greenhouse emissions and possibility of their mitigation from individual sectors:

- Kazakhstan GHG Mitigation Assessment (Climate Change Country Study), 1996
- Kazakhstan GHG Emissions Modeling
- Kazakhstani Regional GHG Emissions Inventory Project (Almaty region), 2001
- Kazakhstani GHG Emissions inventory from Coal Mining and Road Transportation, 2002

Currently, a study of fugitive emissions from oil and gas industry is being carried out by KazNIIMOSK and will be available next year.

3 CO_2 Emissions from Stationary Combustion of Fossil Fuels

Heat and power generation are estimated to be largest contributors of GHG in Russia, Ukraine, and Kazakhstan. Because of their magnitude of their emissions and the strategic importance of heat and power sector for the countries concerned, efforts were undertaken in each of the countries to improve the quality of GHG emission estimation from stationary fossil fuel combustion.

In Russia, electricity generation monopoly RAO UESR has developed a corporate inventory of GHG emissions, which included estimation of carbon emission factors for the fuels burnt at the company facility (coal, heavy oil, gas). Similarly, in Ukraine, US Agency for International Development (US AIID) has sponsored inventory of the largest thermal power plants, which also included estimation of national carbon emission factors and oxidation coefficients. Only coals were examined in the Ukrainian study as coal is the only locally produced fossil fuel. Kazakhstan has developed emission factors for locally used fuels as part of the regional GHG inventory in the Almaty region. However, since the regional research was coordinated by the same agency that compiles the national inventories, research outputs covered the majority of the fuels used in the country.

For the benefit of the inventory community and for the further reference to inventory-related research in the region, we are preserving original methodologies, as well as original terminologies wherever possible. With that note, it needs to be said that there is a variation between how certain terms and concepts are used from study to study. Widely used oil-based fuel known in Russia as *'mazut'* is translated by various authors as heating oil, heavy oil, residual fuel oil, or simply transcribed as mazut. Large power plants that use fossil fuels are either translated as 'thermal power plants' or 'heat and power plants,' both terms being very close to what they are called in Russian. In the source literature Net Calorific Values (NCV) are more commonly referred to as Low Heating Values (LHV), since it is closer to the Russian terminology. For the same reason, oxidation factor is sometimes referred to as unoxidation factor (in Russian '*non-combustion coefficient'*). Additionally, heat calculations in the Former Soviet Union are carried out in calories, which is reflected in the methodologies described below.

The majority of the emission factors described in this section are calculated on the basis of fuel documentation rather then on the basis of direct measurements. Fuels are categorized into certain 'grades' in accordance to classifications stipulated in relevant state standards. State standards also prescribe what methodologies are to be used for calculating fuel qualities and / or emissions from various processes for the purposes of national accounting. These nationally mandated methodologies are referred to as 'normative' throughout the text.

3.1 IPCC methodology based on the revised 1996 IPCC Guidelines and Good Practice Guidance Report (GPG2000)

The methodology for estimation of CO_2 emissions from stationary combustion of fossil fuels recommended by 1996 IPCC Guidelines [5] is based on the following equation:

$$C_r = Q \times NCV \times EF \times (1-Sf) \times F \qquad (1)$$

Where:

C_r	is quantity of carbon released and attributed to fuel combustion (multiplied by 44/12 for CO2)
Q	is quantity of fuel delivered to or consumed by the activity (sector) expressed in natural units
NCV	is net calorific value of fuel (TJ/natural unit)
EF	is carbon emission factor (more precisely, the specific carbon content, t C/TJ)
Sf	is carbon storage factor, that is the fraction of carbon delivered which remains unoxidised after use of the fuel either in a product manufactured from it or because the use does not involve deliberate oxidation of the carbon content.
F	is the oxidation factor, the fraction of carbon which is oxidised during combustion.

Of these values, quantity of fuel delivered and consumed is the basic variable that determines the volume of greenhouse gas emissions in the country in a given year. Net calorific values of the fuels, carbon emission factors, and oxidation factors tend to vary less from year to year. Basic (default) values for net calorific values of the fuels and carbon emission factors are provided by IPCC methodology. However, in order to improve the accuracy of national emission estimates, IPCC recommends to determine appropriate national or local values.

Although IPCC Guidelines do not offer country-specific carbon emission factors, the Reference Manual (Volume III of the 1996 Guidelines) suggests some country-specific assessment of net calorific values, as these tend to vary greatly from one coal-mining region to another, and includes values for Russia, Ukraine, and Kazakhstan. In 2000 Good Practice Guidance [6] these values were up-dated slightly.

The carbon emission factors for coals presented in 1996 IPCC Guidelines and 2000 Good Practice Guidance are mostly based on international assessments:

> Energy Balances of OECD Countries, and Energy Statistics and balances of Non-OECD Countries, OECD/IEA, Paris, 1998.[1]
>
> OECD/IEA (1993), Energy Statistics and Balances of Non-OECD Countries: 1990-1991. International Energy Agency, OECD, Paris, France

[1] A note is made that for the Former Soviet Union and the Yugoslav Republics 1996 numbers were used. These appear to be identical to the 1993 numbers cited below.

Table 3.1. Net Calorific Values and Emission Factors for Solid Fuels as Found in the 1996 IPCC Guidelines [7]

Solid Fuels	Net Calorific Value (GJ/t) (moisture free basis)	Carbon Emission Factor (tC/TJ)
Anthracite	Close to 29 GJ/t	26.8 tC/TJ
Coking coal	Typically between 26 - 29 GJ/t	25.8 tC/TJ
Other bituminous coal*	Between 24 - 29 GJ/t	25.8 tC/TJ
Sub bituminous coal	Varies considerably with quality.	26.2 tC/TJ
Lignite	7 - 17 GJ/t.	27.6 tC/TJ
Peat	Typically about 17-20 GJ/t	28.9 tC/TJ
Patent fuel	Varies depending on the type of patent fuel.	25.8 tC/TJ (default value)
Brown coal briquettes	Accordingly to the quality of brown coal employed.	25.8 tC/TJ (default value)
Coke oven coke (hard coke)	Typically 28 - 29 GJ/t	29.5 tC/TJ
Gas coke	Little information, assumed similar to hard coke.	29.5 tC/TJ

* It is stipulated that the much lower figures for calorific values cited in the *IPCC Guidelines* probably reflect values for unprocessed coal containing non-combustible materials.

Table 3.2. National Net Calorific Values from 2000 Good Practice Guidance

NCV, GJ/t	**Kazakhstan**	**Russia**	**Ukraine**
OIL			
Crude Oil	42.08	42.08	42.08
NGL	41.91	-	-
Refinery Feedst.	-	-	-
COAL			
Coking Coal			
Production	18.58	18.58	21.59
Imports	18.58	25.12	-
Exports	18.58	18.58	21.59
Other Bituminous Coal and Anthracite			
Production	18.58	18.58	21.59
Imports	18.58	18.58	25.54
Exports	18.58	18.58	21.59

NCV, GJ/t	**Kazakhstan**	**Russia**	**Ukraine**
Sub-Bituminous Coal			
Production	-		
Imports	-		
Exports	-		
Lignite-			
Production	14.65	14.65	14.65
Imports	18.58	-	14.65
Exports	18.58	14.65	14.65
OTHER FUELS			
BKB	-	-	29.31
Coke Oven Coke	25.12	20.1	-
Gas Coke	-	25.12	25.12

Since each coal-mining basin bears different types of coals, the systems for gradation and classification of coal is different in each of the coal-mining countries, although certain typology remains constant. In Russia, Ukraine, and Kazakhstan special efforts have been made to develop local carbon emission factors for the local coal types.

3.2 National net calorific values and carbon emission factors (specific carbon content of fuels)

3.2.1 National values: Kazakhstan [4], [8]

Kazakhstan has developed by far the most comprehensive approach to estimating national greenhouse gas emissions for fuel combustion and has developed local factors for a variety of local fuels.

The data on consumption of fuel is submitted to the Statistics Agency of Kazakhstan in statistical reporting form #1-TEB. The form is submitted by all the economic entities that supply or consume fuel and employ more then 20 people, regardless of their activity type. The form lists 25 types of fuel, which do not directly correspondent to IPCC fuel types. KazNIIMOSK therefore developed a conversion table to match fuels used in Kazakhstan with fuel categories provided by IPCC.

Methodology note:

In its annual inventories estimated under the Reference approach, Kazakhstan modified the basic equation in the IPCC Guidelines:

Fuel burned = (Production) + Imports - Exports ± Stock Change (2)

to include estimates of the fuel lost

Fuel burned = (Production) + Imports - Exports ± Stock Change - Fuel Lost, (3)

where the fuel lost was defined as fuel that has been produced but not consumed due to losses in delivery, transport, accidents, etc. The information on the quantities of the lost fuel is submitted by Kazakh economic entities to the Statistics Agency of Kazakhstan along with regular information on the quantities of consumed and stockpiled fuel, as part of the regular statistics. Therefore the each enterprise reports three major values related to fuel consumption: the amounts of fuel consumed, stockpiled, and lost. Aggregated data on fuel lost collected by the Kazakhstan Statistical Agency is then used to estimated total quantity of fuel lost under the reference approach. In 2001, fuel lost made up 0 to 5% of each fuel type consumed by the Kazakh economy.[4]

Table 3.3. Correspondence between IPCC and Kazakh fuel types [4]

IPCC fuels	**Kazakh fuels**		
IPCC fuel category	Kazakh fuel category	Net Calorific Value GJ/t	Carbon Emission Factor, tC/TJ
Crude oil	Crude oil	**40.12**[CS]	**20.31**[CS]
	Gas condensate		
Gasoline	Aviation Gasoline	**44.21**[CS]	**19.13**[CS]
	Vehicle gasoline		
	Gasoline-like jet fuel		
Jet kerosene	Kerosene-like jet fuel	**43.32**[CS]	**19,78**[CS]
Other Kerosene	Kerosene for lighting and other purposes	44.75[D]	19.6[D]
Gas and diesel oil	Diesel fuel	**43.02**[CS]	**19.98**[CS]
	Domestic furnace fuel	**42.54**[CS]	**20.29**[CS]
	Motor fuel for slow diesel vehicles	**42.34**[CS]	**20.22**[CS]
Residual fuel oil	Heating oil (mazut)	**41.15**[CS]	**20.84**[CS]
	Navy mazut (oil)		
LPG	Liquefied propane and butane	47.31[D]	17.2[D]
	Liquefied carbohydrate gases		
Shale oil	Oil and shale bitumen	40.19[D]	22[D]
Lubricants	Spent lubricants (other lubricants)	40.19[D]	20[D]
Petroleum coke	Petroleum and shale coke	31.0[D]	27.5[D]
Other types of fuel	Other types of fuel	29.309[D]	20[D]
Coking coal	Karaganda coking coal	**24.01**[CS]	**24.89**[CS]
Sub-bituminous coal	Hard coal	**17.62**[PS]	**25.58**[PS]
Lignite	Lignite (brown coal)	**15.73**[PS]	**25.15**[PS]
Coke	Hard-coal coke and half coke	25.12[D]	29.5[D]
Coke oven gas	Coke oven gas	**16.73**[PS]	13[D]
Blast furnace gas	Blast furnace gas	**4.19**[PS]	66[D]
Natural gas	Natural gas	**34.78**[CS]	**15.04**[CS]
Biomass	Heating wood	**10.22**[CS]	**29.48**[CS]

Notes:
D – IPCC default;
CS – country specific data;
PS – plant specific data.

For heating oil, diesel fuel, sub-bituminous coal, and lignite uniform national net caloric values and carbon emission factors were calculated based on weighted averages of the consumption of fuel grades within one fuel sub-type from the national energy balance.[2] Disaggregated emission factors for individual fuel sub-types are shown in Table 3.4. Since these are weighted average fuel, they are year-specific and are up-dated by KazNIIMOSK on the annual basis.

Table 3.4. Averaged national net calorific values and carbon emission factors (2001 inventory)

Fuel category	Net Calorific Value GJ/t	Carbon Emission Factor tC/TJ
Heating oil	41.15	20.84
Diesel fuel	43,00	19,99
Sub bituminous coal	17,62	25,58
Lignite	15,73	25,15

Emission factor estimation methodology

National net calorific value and carbon emission factors for various types of fuel used in Kazakhstan were drawn from a variety of sources. The values for crude oil, gasoline, jet kerosene, diesel oil, heating oil, coal, and natural gas were calculated by the researchers of Kazakh Scientific Research Institute of Electric Power Industry (KazNIPIenergoprom). The values for coke oven and blast furnace gases were provided by Karaganda-based coal-mining company *Ispat-Karmet.* The net calorific values that were calculated were compared with the national averages put together on the basis of the data collected by the Statistic Agency of Kazakhstan.

A. Determination of carbon emission factors for solid and liquid fuels

The so-called Mendeleev's equation was used to define the carbon emission factors for solid and liquid fuels. The equation is used in thermal power plant engineering and connects the net calorific value and the composition of fuel:

$$Q^{daf} = 81*C + 300*H - 26*(O - S) - j*(9H + W), kcal/kg^{3} \qquad (4)$$

Where:

Q^{daf}	is net calorific value of fuel (on dry and ash-free basis),
j	is a conversion factor used to express the result in kcal/kg and equals 5.83,
C, H, O	is the content of carbon, hydrogen and oxygen respectively in operational mass of fuel, %,

[2] To improve accuracy of the emission data, the inventory compliers also calculated weighted averages of national net calorific values and carbon emission factors of heating oil, diesel fuel, sub-bituminous coal, and lignite for major economic sectors. Because of their marginal value to the outside researchers, these values are not presented in this report.
[3] Another way of expressing the Mendeleev's formula is: Q^{daf}=339.5*C+1256*H-25.8(9H+W)-109(O-S)
$Q_н$ = 34,013 C + 125,6 H – 10,9(O – S) – 2,512(9H + W) MJ/kg ,

S is the sulfur content in dry mass of fuel, %,
W is the total amount of moisture in the operational mass of fuel, %.

Based on this equation, the specific carbon content of fuel per energy unit was determined as:

$C = 29,46 - 176,76*a / Q^{daf}, \quad tC/TJ,$ (5)

Where:

Q^{daf} is the net calorific value per working mass, kcal/kg,
a is a factor describing the composition of the fuel working mass and determined as:
$a = 41*H - 4.3*(O - S) - W,$
where H, O, S, and W are respectively hydrogen, oxygen, sulfur and moisture contents working mass of fuel, %.

According to the results of calculations made for fuels used in Almaty region the a/Q ratio was determined as 0.02-0.03 for coal and 0.05 for low-sulfur residual fuel oil.
The results of carbon emission factors calculation for fossil and liquid fuels are presented in Table 3.5. The table also indicates original sources of the data, a quick summary of which is provided below:

- statistical reporting data from energy enterprises for 1999 – 2000,
- data on chemical analysis of Karaganda concentrate coal (obtained based on the analysis carried out by KazNIPIenergoprom as a part of ecological audit Heat and Power Plant #1 belonging to Closed Joint Stock Company *Almaty Power Consolidated* (APC) conducted in 1997) [9],
- state standards and technical conditions for different types of fuel (references) [10-14],
- data from KaragandaGIPROSHAKHT institute,
- data from reference books [15].

Table 3.5. Carbon emission factors for fuels used in Almaty region

Fuel description		Net Calorific Value		a	a/Q	Carbon Emission factor, tC/TJ	Carbon Oxidation factor	Data source
		kcal/kg	TJ/ths t TJ/mln m^3					
Solid Fuels								
Coal origin	**Coal Type**							
1. Karaganda	Concentrate	5730	24.01	148.2	0.0259	24.89	0.985	Ecological audit of APC's HPP-1, 1999 (Chemical analysis of averaged coal sample)
2. Karaganda	Concentrate	5441	22.8	146.3	0.0269	24.71	0.985	Reporting data of APC's HPP-1 for 2000
3. Karaganda	Middlings	3880	16.26	83.5	0.0215	25.66	0.985	Normative method
4. Karaganda	Regular	5090	21.33	110.1	0.0216	25.64	0.985	Normative method
5. Ekibastuz (whole basin)	Regular	4000	16.76	85.2	0.0213	25.69	0.98	Normative method
6. Ekibastuz I group	Regular	4150	17.39	91.4	0.022	25.57	0.98	State standard OU 654 RK 01 6 1945.101-97
7. Ekibastuz II group	Regular	3480	14.58	80.9	0.0233	25.35	0.98	State standard OU 654 RK 01 6 1945.101-97

8. Kuu-Chekinsk	Regular	3910	16.38	78.5	0.0201	25.91	0.98	Normative method
9. Kuu-Chekinsk	Regular	4449	18.64	88.4	0.0199	25.95	0.98	Reporting data APC's HPP-3 for 1999
10.Maykunensk	Regular	3768	15.79	94.3	0.025	25.04	0.985	Data from Karaganda GIPROSHAKHT institute
11. Borlinsk	Regular	3850	16.13	126.3	0.0328	23.66	0.985	
12. Shubarkol	Regular	4750	19.9	87.2	0.0184	26.21	0.985	
Liquid Fuels								
Fuel type	**Description**							
13. Residual fuel oil I-100	Low-sulfur	9869	41.35	478.7	0.0485	20.89	0.995	Reporting data of APC's HPP-1 for 2000
14. Residual fuel oil I-100	Low-sulfur	9770	40.94	478.7	0.049	20.8	0.995	State standard 1058599
15. Residual fuel oil I-40	Low-sulfur	9821	41.15	478.7	0.0487	20.84	0.995	State standard 1058599
Other Fuels								
Fuel type	**Description**							
16. Wood	Domestic	2440	10.22	-0.3	-0.0001	29.48	0.98	Normalizing method
17. Natural gas	Bukhara-Ural pipeline	8175	34.25			15.03	0.995	Reporting data of APC's HPP-1 for2000

B. Determination of carbon emission factors for gaseous fuels

The natural gas is supplied to Kazakhstan from the neighboring Uzbekistan by a gas-pipeline. To estimate the carbon emission factor of the supplied natural gas, its physical properties were calculated based on the existing reference data. The percentage composition of the mixture gases from Bukhara-Ural pipeline was taken from reference book [15]. Physical gas properties were calculated in accordance with *State Standard #30319.3-96.*[14]. Based on the calculation of the physical properties, corresponding carbon content in the gas mass and specific carbon content per thermal unit were derived. Table 3.6 contains the results of calculations for natural gas. The fraction of carbon oxidized was determined as 99.5 % in accordance with the reference data.

Table 3.6. Physical properties of the natural gas from Bukhara-Ural pipeline.

Compound	Vi, %	i, kg/m³	g, kg/m³	mi, kg/mole	mg, kg/mole	g, (share)	Share of element, %				Q_{min} kcal/m³	
							C	H	N	O	Q_{min} i	Q_{min} g
CH_4	94.9	0.6682	0.6341	16.043	15.225	0.899	67.3035	22.5903	-	-	7980	7573.02
C_2H_6	3.2	1.2601	0.0403	30.070	0.962	0.057	4.5667	1.1495	-	-	14300	457.60
C_3H_8	0.4	1.8641	0.0075	44.097	0.176	0.011	0.8637	0.1933	-	-	20670	82.68
i-C_4H_{10}	0.1	2.4956	0.0025	58.120	0.058	0.004	0.2924	0.0613	-	-	27236	27.24
n-C_4H_{10}	-	2.4880	-0	58.120	-	-	-	-	-	-	-	-
i-C_5H_{12}	0.1	3.1740	0.0032	72.146	0.072	0.004	0.3745	0.0754	-	-	34400	34.40
n-$C5H_{12}$	-	3.1470	-	72.146	-	-	-	0.958	-	-	34400	-
C_6H_{14}	-	3.8980	-	86.172	-	-	-	-	-	-	38540	-
C_7H_{16}	-	4.7550	-	100.198	-	-	-	-	-	-	38540	-
C_8C_{18}	-	5.8120	-	114.224	-	-	-	-	-	-	-	-
C_9H_{20}	-	5.0300	-	128.250	-	-	-	-	-	-	-	-
$C_{10}H_{22}$	-	0.7300	-	142.276	-	-	-	-	-	-	-	-
N_2	0.9	1.1649	0.0105	28.016	0.252	0.015	-	-	1.4862	-	-	-
H_2S	-	1.4311	-	34.080	0	0	-	-	-	-	5200	-
CO_2	0.4	1.8393	0.0074	44.011	0.176	0.010	0.2910	-	-	0.7583	-	-
	100		0.7054		16.922		73.6919	25.028	1.4862	0.7583	-	8174.94
											Q_{min}g converted to MJ/m³	**34.25**
Number of atoms							1.0392	4.2352	0.0180	0.0080		
Molecular mass					17.085		12.4701	4.2352	0.2515	0.1283		
Specific hydrocarbon emission, converted into CH_4, %					0.0045							
CO_2 emission factor, kg/kg					2.6646							
Specific carbon content, kg/kg					0.730							
Specific carbon content, kg/m³					0.515							
Carbon emissions factor, t C/TJ					**15.03**							

3.2.2 National values: Russia [16, 17, 18]

National emission factors in Russia were developed as part of the corporate GHG Emissions Inventory of the Russian Joint Stock Company *Unified Energy System of Russia* (RAO UESR), Russia's electric power generation monopoly and one of the world's largest utility companies. RAO UESR's inventory of greenhouse gas emissions encompasses almost entire thermal power sector of Russia. RAO UESR's emissions constitute about 30% of total Russian CO_2 emissions, accounting for about 89% of Russia's fuel consumption in the thermal power industry. The inventory covered emissions from 357 thermal power plants (TPPs) and boilers owned by 77 regional energy companies that make up RAO UESR. The GHG emissions inventory completed in 1999 originally covered years 1990 to 1997 and included calculation of fuel specific emission factors. Currently the factors that were developed in 1999 are being used to calculate the company's annual corporate greenhouse gas emissions, and to estimate greenhouse gas emissions from individual facilities.

RAO UESR calculated the national and local fuel-specific CO_2 emission factors for three types of fuel: coal, residual fuel oil (also known as "heavy oil" or "mazut") and natural gas. It is important to note that RAO UESR's emission factors were developed for the purposes of corporate

GHG accounting and only later on independent efforts were made to adopt them in accordance with IPCC methodology to the national inventory needs. The company's goal was to obtain one CO_2 emission factor for each fuel category (solid, liquid, gaseous), which would already include correction for unoxidation and which could be used as a single multiplier when calculating consequent annual inventories. We present RAO UESR's methodology in its original form, along with derived national carbon emission factors.

Solid fuels

To identify the CO_2 emission factors for the country as a whole, RAO UESR gathered experimental and reference data for each type of solid fuel that constituted more than 1% of the fuel balance in the power and heat sector. This definition mostly limited the scope of study to the majority of coals combusted at RAO UESR facilities. In addition to coal, some power plants use other types of solid fuel (e.g., peat and bark), but their share in the fuel balance of the company is negligible.

The Russian power and heat sector combusts about 160-200 types of fossil coals and related products. During the time period covered by the inventory (1990–1997), RAO UESR burned coal from eight major coal-producing basins located in the Russian Federation and Kazakhstan[4]. These include coals from the Kuznetsky (20%–25%), Kansko-Achinsky (18%–19%), Ekibastuzsky (16%–19%) basins; eastern Siberia (~15%) and the Far East (~10%); as well as coals from the Donetsky (4%–5%), Pechorsky (~4%), and the Podmoskovny (1%–2%) basins. Each basin contains one or more mines, and each mine produces coals of varying grade, thus the characteristics of coal may differ significantly even within one basin. For example, currently there are 68 coal mines and 16 open-pit mines operating in the Kuznetsky coal basin. Different grades of coal have slightly different characteristics of carbon content, heat power and ash.

To estimate its corporate CO_2 emissions from coal combustion, RAO UESR calculated one aggregate average CO_2 emission factor for each of the eight coal basins (i.e. coal-mining regions), based on the weighted averages emission factors of coal grades produced within the basins. The CO_2 emissions from each grade of coal combusted depend on the particular qualities of that grade, the characteristics of the power plant in which it is burned, and the completeness of combustion (fraction of carbon oxidized). To calculate the CO_2 emission factors for the different grades of coal, the following general equation was used: [5]

$$EF_{CO_2} = \frac{44}{12} \cdot C^{daf} \cdot \frac{7000}{Q^{daf}} \cdot \varepsilon \,, \qquad (6)$$

where

EF_{CO_2}	specified emission factor, tCO_2/tce (ton of coal equivalent),
44/12	factor for recalculation of carbon emissions into CO_2 emissions (tCO_2/tC),
C^{daf}	carbon content of coal on dry and ash-free basis, %
Q^{daf}	net calorific value of coal on dry and ash-free basis, kcal/kg,
7000	conversion factor for recalculation in coal equivalent (ce) units: *kcal/kg ce: 1 kg ce=7000 kcal*

[4] It is estimated that the coal burnt at RAO UESR facilities makes up 20% of the total coal consumption in Russia. [17]

[5] This methodology is consistent with international approach, as for example in EMEP/CORINAIR Emission Inventory Guidebook [18]. However, IPCC Guidelines suggest accounting for incomplete carbon oxidization separately.

ε fraction of carbon oxidized, %.

RAO UESR applied different factors for C^{daf} and Q^{daf} to each grade of coal and each basin. These values for each of the analyzed grades of coal were taken from the reference book *Energy Fuel of USSR* [15].

Different carbon oxidation factors were used for each basin, although distinction between different grades within each basin was not made. The basic information for calculating carbon oxidation factors was taken from the 3-Tech statistical reporting form submitted by the inventoried utilities.

An example of the calculation of a CO_2 emission factor for a particular coal basin is shown in Tables 3.7 and 3.8.

Table 3.7. Example: Chemical characteristics of 'DR' grade coal from the Kuznetsky basin

Coal grade[6]	**'DR' grade coal**
Moisture content	11.5%
Ash content	18.0%
Net calorific value	7310 kcal/kg
Chemical characteristics (in dry, ash-free state of fuel):	
Carbon content	77.7%
Hydrogen content	5.5%
Nitrogen content	2.6%
Oxygen content	13.7%
Sulfur content	0.5%

Source: [17] with reference to [15]

Table 3.8. CO2 emission factors for coals from the Kuznetsky basin ([17] with reference to [15])

Mine	Coal grade (Russian abbreviation)	C_i^{daf}, %	Q_i^{daf}, Kcal/kg	CO_2 emission factor, t CO2/tce	Carbon emission factor, t C/TJ
Kuznetsky	DR, DSSh	77.7	7 310	2.634	24.5
	GR, GMSSh, GSSh	80.5	7 620	2.621	24.4
	SS2SSSSh, SS2SSR	88.0	8 130	2.693	25.1
	SS1SSSSh, SS1SSR	83.5	7 760	2.673	24.9
	TOMSSh, TSSch, TR	89.5	8 120	2.744	25.5
	K, SS, promproduct	88.0	8 120	2.697	25.1
	K, SS, prompr. + otsev SS	84.5	7 900	2.658	24.7
	K, KZh, SS, shlam	88.4	8 230	2.673	24.9
Yuzhnaya	SS1SSSSh	83.5	7 760	2.673	24.9
Severnaya	SS1SSR	84.5	7 870	2.668	24.8
Kiselevskaya	SS1SSR	82.6	7 660	2.678	24.9
Dalnie Gory	SS1SSR	83.5	7 750	2.676	24.9
Im. V. N. Volkova	SS1SSR	83.5	7 850	2.642	24.6
Boutovskaya	SS2SSR	88.4	8 170	2.693	25.1
Krasnokamenskaya	SS2SSSSh	87.0	8 080	2.678	24.9
Im. V. V.Vakhrusheva	SS2SSR	89.0	8 190	2.705	25.2

[6] Also sometimes referred to as coal *mark* following Russian terminology.

Yagunovskaya	SS2SSR	88.0	8 130	2.693	25.1
Shushtalepskaya	TR	90.0	8 160	2.746	25.6
	SSROK1	86.9	7 920	2.729	25.4
	SSROKP	79.9	6 930	2.860	26.6

The emission factors for each of the basins were derived from specific emission factors for each of the coal grades produced within the basin. The aggregate emission factor for a basin was obtained as a weighted average of the emission factors for all the coal grades produced within the basin. Appropriate weighting coefficients were calculated based on the share of the production of each coal grade in the total volume of coal production within a basin in 1990.

Table 3.9. Averaged carbon emission factors for various coal-mining regions [18]

	Carbon EF, tC/TJ	CO_2 EF, tCO_2/thousand tce
Kuznetsk coal-mining basin	25.05	2.692
Kansk-Achnisk coal-mining basin	26.74	2.874
Ekibasutuesk coal-mining basin	25.80	2.773
Eastern Syberia	25.88	2.781
Far East	25.40	2.730
Donetsk coal-mining basin	24.61	2.645
Pechorsky coal-mining basin	25.29	2.718
Moscow region coal-mining basin	25.92	2.758

In a similar way, RAO UESR calculated an aggregate emission factor for all of the coal consumed by the Russian power sector (so-called 'energy coal'). For this purpose, each of the emission factors for eight coal mining basins were averaged, taking into account the share of the consumption of coal from each basin in the total volume of coal consumption in the sector in 1990.[7]

Natural Gas

Natural gas is delivered to the power plants from different gas deposits, each of which has different physical and chemical properties. Therefore, as in the case of solid fuel, RAO UESR derived an average carbon dioxide emission factor by calculating an average value for all gases combusted at the plants. The data on gas composition (CH_4, C_2H_6, etc.) and heat of combustion were taken from [15].

The *Adopted Guidelines* [19] stress that that the coefficients for natural gas are also always almost the same, since most of Russia is supplied with West Siberian gas. Insignificant differences are observed for carbon emission factors for gas from gas pipelines Central Asia – Center and Saratov – Moscow, while Orenburg gas is quite different.

The carbon oxidation factor for natural gas combustion was assumed to be 100%, based on the nearly complete combustion of gas at large thermal power plants [21]. The *Adopted Guidelines* recommend using oxidation factor of 0.999.

The analysis of the facility level emissions performed by RAO UESR in 2002-3 showed that even upon close examination the variation of the emission factors from natural gas combustion

[7] Note: Averaged emission factors for the basins were derived based on production data, while the national emission factor is based on the consumption data.

was small (1.62, 1.61, 1.63 for three facilities examined) and correlated well with the originally calculated value.

Table 3.10. Average Carbon Emission Factors from gas supplied to large power plants in Russia (with correction for carbon oxidation factor)

	CEF, tC/TJ	CO_2 EF, tCO_2/thousand tce
Average for all pipelines other then those indicated below. Gas from Western Syberia	14.95	1.608
Central Asia – Center pipeline	15.11	1.625
Saratov – Moscow pipeline	14.86	1.599
Orenburg – Alexander Gai pipeline	16.01	1.722
Moscow TransGas (closed cicle)	14.93	1.606

Liquid Fuels

The guidelines indicate that according to RAO UES data, the characteristics of the heating oil used by large power plants in Russia are almost identical (although they are somewhat different from those given in IPCC Guidelines because the mazut used in Russia is largely characterized by high sulphur content. The initial data on carbon content and the lowest heat value for high-sulfuric residual oil (mazut) combusted at the power plants were taken from [21]. In addition to residual oil, some plants located in, for example, the eastern part of Russia, combust diesel fuel and petroleum coke. But because the share of these fuels is insignificant, they were not considered separately in the inventory. As in the case of gaseous fuels, carbon oxidation was assumed to be 100%, based on the assumption that combustion of liquid fuel at large thermal power plants is almost complete [21].

The average CO_2 emission factors calculated as a weighted average for each type of fuel (solid, liquid, gaseous) are presented in Table 3.11. Final Carbon emission factors that were obtained by RAO UES were recalculated and presented without discounting for partial oxidation. This was done because fuel combusted at large electric power plants is oxidized much better then on average in Russia.

Table 3.11. Comparison of RAO UESR and IPCC default carbon emission factors for coal, residual fuel oil, and gas (without adjustment for incomplete combustion)

	RAO UESR		IPCC
	CO_2 emission factor tCO_2/thousand tce	*Carbon emission factor, tC/TJ*	*Carbon emission factor, tC/TJ*
Coal	2.76	25.68	26.2
Gas	1.608	14.95	15.3
Residual fuel oil	2.28	21.11	21.1

3.2.3 National values: Ukraine

The majority of the work on the national inventories in Ukraine was done through the activities of technical assistance agencies of the US and Canada, implemented for the most part by the Institute of Energy of the Ukrainian Academy of Sciences. A Canadian study [27] examined the national system for collecting information on the fuels consumed, while a study sponsored by US Agency for International Development (US AID) examined more closely GHG from the energy sector [28].

As in other countries, information on the fuels consumed by the Ukrainian economy is collected by the national statistics system. Since the Soviet times, the main task of collecting such information was to facilitate the setting of sectoral fuel use quotas. Because of that, the national statistics on fuel consumption is organized on the principle of the ministerial hierarchy. Therefore, neither sectoral division nor nomenclature of fuels of national statistics coincide with IPCC categories and fuel types. For example, in the category "Road transportation" natural gas is used as engine fuel and for heating. Additionally, the nomenclature of consumed fuel include the fuel types, which are not described by the IPCC methodology, for example, stove fuel, engine fuel etc.[8]

As part of the effort to improve inventory system in Ukraine, an algorithm was develop to match Ukrainian fuel categories with IPCC fuel categories (Table 3.12).

Table 3.12.Correspondence between Ukrainian fuel types and IPCC fuels [27]

IPCC fuel types	*Ukrainian fuel types*	*IPCC fuel types*	*Ukrainian fuel types*
LIQUID FUEL		**SOLID FUEL**	
Primary fuel products		*Primary fuel products*	
Crude Oil	Oil including condensed gas	Anthracite	Coal
		Coking Coal	
Orimulsion		Other Bit. Coal	
Natural Gas Liquids	Liquid natural gas	Sub-bit. Coal	
Gasoline	Gasoline	Lignite	
Jet Kerosene		Oil Shale	Oil shale
Other Kerosene	Kerosene	Peat	Peat briquettes
Shale Oil			Peat (nominal damp)
Gas / Diesel Oil	Diesel fuel	*Secondary fuel products*	
Residual Fuel Oil	Residual fuel oil	BKB & Patent Fuel	Coal briquettes
	Bunker fuel	Coke Oven/Gas	Coke and coke breeze
LPG		Coke	
Ethane		**GASEOUS FUEL**	
Naphtha	Naphtha	Natural Gas (dry)	Natural gas
Bitumen	Petroleum bitumen	Blust furnace gas	
Lubricants	Lubricants	Coke gas	Coke gas
Petroleum Coke	Petroleum coke	**BIOMASS**	
Refinery Feedstocks	Refinery feedstocks	Solid Biomass	Fuel wood
Other Oil	Stove fuel	Liquid Biomass	
	Engine fuel		
	Gas turbine fuel		
	Waste oil products	Gas Biomass	
	Other types of fuel		

A separate effort was also undertaken to improve the information on GHG emissions from power generation. In 2000-2001, the US AID together with the Ministry of Fuel and Energy of Ukraine and the Institute of Energy of the Ukrainian Academy of Sciences have carried out a study

[8] At the times of the Soviet Union, fuel nomenclature included hundreds of fuel grades. After a series of revisions since 1991, as of 1999, the Ukrainian fuel consumption statistics include 32 economic sectors and subsectors and 26 types of fuel.

on development of national emission factors on large thermal power plants in Ukraine [17]. The local carbon emission factors for specific types of fuel have been developed using data from the directories [15, 29] which provide detailed information on the elemental composition and heat value of a fuel used for most of the Ukrainian coal-mines and coal-dressing mills. The local carbon emission factors have been found for the following types of Ukrainian coal: anthracite, lean coal and jointly for gas and candle coal. These are the coals that are supplied to electricity enterprises operated by the Ministry of Fuel and Energy of Ukraine.

The methodology for estimating the emission factor k_C was based on the equation:

$$k_C = \frac{C^{daf}}{100} \cdot \frac{1000}{Q_i^{daf}}, \text{ kg/GJ or Mg/TJ,} \qquad (7)$$

where C^{daf} is carbon contained in the combustible mass of fuel, %;
Q_i^{daf} is low heat value of the combustible mass of fuel, MJ/kg.

The carbon oxidation factor ε characterizes the efficiency of fuel carbon combustion. As chemically analyzed, carbon accounts for most combustible materials in light ash and slag. Therefore, an indicator of heat losses due to combustible loss may be used to find a local carbon oxidation factor for a boiler. A value of heat loss for all of the fuels used for a boiler was found in [4] by:

$$q_4 = \left(a_{sl} C_{sl} + a_{esc} \frac{C_{esc}}{100 - C_{esc}} \right) A^r \frac{Q_C}{Q_{i(SF)}^r} K_Q d_{SF} \text{ ,\%,} \qquad (8)$$

where

a_{sl}, $a_{вesc}$ is fuel ash shared in slag and escape;
C_{sl}, C_{esc} is combustible matters contained in slag and escape, %;
A^r is ash content in combustible mass of fuel, %;
Q_C is heat value of 1 kg of carbon which is 32.657 MJ/kg;
$Q^r_{i(SF)}$ is low heat value of combustible mass of solid fuel, MJ/kg;
K_Q is correction factor counting added heat to furnace with fuel, air and steam;
d_{SF} is solid fuel shared (for heat) in total fuel burned in boiler; i.e. heat release of solid fuel shared in total heat release of the whole fuel burned in boiler (solid, liquid and gaseous fuels).

The heat loss of solid fuel due to a combustible loss is found as:

$$q_{4(SF)} = q_4 / d_{(SF)} \text{ .} \qquad (9)$$

The specific quantity of unburned carbon is $1000 \cdot q_{4(SF)}/(100 \cdot Q_C)$, kg/GJ. On the other hand, the carbon emission factor is a specific quantity of carbon in fuel. Then, the local carbon oxidation factor for a boiler may be found by:

$$\varepsilon = 1 - \frac{1000 q_{4(SF)}}{100 Q_C} \cdot \frac{1}{k_C} . \qquad (10)$$

Statistical reporting form #*3-tech* "Report on Thermal Power Plant Operation. Performance Parameters," which is submitted to the energy association (=company) that the enterprise is part of and to the Ministry of Fuel and Energy, provides information on the total heat loss due to incomplete combustion of fuel. For the enterprises with dust-and-coal boilers that are lacking information on heat losses due to combustible losses, the value of $Q_{4(SF)}$ was assumed as that in data from [29]. According to [30], the correction factor K_Q for the Ukrainian Thermal Power Plants is virtually adequate to 1.

In their reports, the thermal power enterprises do not provide information on the chemical (elemental) composition of the fuel, as this would require technological analysis of the fuel. Therefore, the study assessed the local carbon emission factors for specific types of fuel based on the data from the directories [15, 29], which provide detailed information on the elemental composition and heat value of fuel used for most of the Ukrainian coal-mines and coal-dressing mills.

The carbon emission factors for mayor Ukrainian coal types was determined using data on the coal which is produced and processed by mines and dressing mills of Ukraine. The number of mines surveyed varied as there is a degree of specialization in the types of coal that the mines produce. Tables 3.14, 3.15, and 3.16 summarizes the data on the carbon content, low heat value and an emission factor for each of the coal sources in Ukraine. The study recommends to use the averaged value for all of the coal sources as the national carbon emission factor. Summary of the national emission factors and their comparison with IPCC default emission factors is presented in Table 3.13.

Net calorific values (also known as Low Heating Value, LHV) of coals are determined by the molecular analysis of fuels and depends not only on carbon, hydrogen, and oxygen content in coal but also on ash and water content. Low Heating Values and Ash Content of coal used in 1999 and 2000 at some Ukrainian TPPs are shown in the Table 17. LHV increased greatly and ash content of coal consumed by the Ukrainian coal-fired power plants was reduced in 2002 in comparison with 1999, and it had a positive effect on the efficiency of boilers and power units.

Table 3.13. Difference between national emission factors and IPCC emission factors

	National emission factor, tC/TJ	Number of sources examined	Standard deviation	IPCC emission factor, tC/TJ	Difference, %
Anthracite:	28.16	32 mines and dressing mills	0.44	26.8	6.56
Lean coal:	26.05	19 mines and dressing mills	0.41	26.8	2.29
Gas coal and candle coal:	25.19	45 mines and dressing mills	0. 26	25.8	0.5

Table 3.14. Gas Coal and Candle Coal Characteristics

Enterprises	***Type***	C^{daf}	Q_i^{daf}	k_c
		%	MJ/kg	kg/GJ
Ukraina CM	D, screenings	74.2	29.60	25.07
Ukraina CM	D, concentrate	78.5	31.07	25.27
Kurakhiv CM	D, concentrate	76.0	29.85	25.46
Mine No 105	D, concentrate	76.8	30.61	25.09
Hirnyk Mine	DMSSH	76.4	29.89	25.56
Pryvilnyanska CM	DSSH	74.7	29.52	25.30
60 Yr. Sov. Ukr. Mine	DR	74.6	29.68	25.13
Trudivska Mine	DSSH	75.4	30.14	25.02
Abakumov Mine	GSSH	77.9	30.65	25.42
Chelyuskintsi Mine	GR	77.0	30.61	25.16
Lenin Mine	GR	77.6	31.15	24.91
Karbonit Mine	GR	79.1	31.95	24.76
Hirska CM	G, screenings	76.1	30.14	25.25
Dimitrov Mine	GSSH	81.2	32.66	24.86
Central Mine	GR	81.6	32.62	25.02
Central Mine	GSSH	81.8	32.82	24.92
Novodruzheska Mine	GR	78.2	31.15	25.10
Kreminna CM	GSSH	74.7	29.64	25.20
Kreminna CM	G, concentrate	77.7	30.90	25.15
Bilorichensk CM	G, screenings	77.8	31.07	25.04
Slovyanoserbsk CM	G, concentrate	78.6	31.28	25.13
Mikhailivska CM	G, concentrate	81.5	32.82	24.83
Komsomol Ukrainy CM	G, pp	76.0	30.40	25.00
Rossiya CM	G, screenings	77.8	31.11	25.01
Krasnoarmiysk CM	G, concentrate	80.1	32.24	24.84
Pioner CM	G, slag	76.5	30.44	25.13
Ternivska Mine	GR	77.1	30.40	25.36
Pershotravneva Mine	GR	80.5	32.66	24.65
Dniprovska Mine	GR	77.3	30.06	25.72
Pavlograd Mine	GR	78.0	30.48	25.59
Samara Mine	GR	75.2	29.64	25.37
CPSU 26 Congress Mine	GR	80.7	32.22	25.05
Yuvileina Mine	GR	81.4	32.36	25.15
Novovolynsk Mine No 1	M	79.90	31.44	25.41
Novovolynsk Mine No 4	M	77.80	30.86	25.21
Novovolynsk Mine No 3	R	79.00	31.19	25.33
Novovolynsk Mine No 5	R	78.80	31.02	25.40
Novovolynsk Mine No 6	R	79.90	31.15	25.65
Novovolynsk Mine No 7	R	79.10	30.90	25.60
Novovolynsk Mine No 9	R	79.40	31.32	25.35
Novovolynsk Mine No 1	SSH	79.80	31.53	25.31
Novovolynsk Mine No 4	SSH	77.80	30.79	25.27
Chervonograd CM	SSH	79.90	31.15	25.65
CPSU 25 Congress Mine	R	81.50	32.78	24.86
USSR 60 YR. Mine	R	80.40	32.26	24.92
Mean value				25.19
Standard deviation				0.26

Table 3.15.Ukrainian Anthracite Characteristics

Enterprises	**Type**	C^{daf}	Q_i^{daf}	k_c
		%	MJ/kg	kg/GJ
Khrustalska Mine	ARSH	91.0	32.82	27.73
Prapor Komunizmu Concentrating Mill (CM)	ASH	92.2	32.99	27.95
Prapor Komunizmu CM	A, slag	91.2	32.11	28.40
Miusinska CM	ASH	93.6	33.29	28.12
Miusinska CM	A, slag	90.7	31.48	28.81
Izvestiya CM	A, slag	91.9	32.76	28.05
Novopavlovska CM	ASH	94.1	32.87	28.63
Novopavlovska CM	A, slag	92.0	32.66	28.17
Dzerzhinsky Mine No 2	ARSH	93.8	32.91	28.50
Frunze Mine No 31-32	ARSH	93.7	33.29	28.15
Rovenki CM	ASH	95.0	33.03	28.76
Rovenki CM	A, slag	93.4	32.62	28.63
50 Years Sov. Ukr Mine	ASH	89.8	32.03	28.04
Lisova Mine	ARSH	91.9	33.91	27.10
Mine No 3-bis	ARSH	92.0	33.66	27.33
Snizhnyanska CM	ASH	93.1	32.53	28.62
Thorez CM	ASH	94.0	33.66	27.93
Thorez CM	A, slag	90.5	31.99	28.29
Krasnaya Zvezda CM	ASH	94.9	34.00	27.91
Krasnayz Zvezda CM	A, pp	93.5	33.29	28.09
Volodarsky Mine	ARSH	94.1	33.49	28.10
Mine No 69	ARSH	94.1	33.16	28.38
Krasnjpartizanska CM	ASH	92.9	33.09	28.07
Vakhrushev CM	ASH	93.9	32.91	28.53
Khrustalska CM	ASH	91.3	33.43	27.31
Komendantska CM	A,pp	91.4	32.41	28.20
Yanivska CM	A,pp	90.6	32.22	28.12
Central CM	ASH	94.7	32.96	28.73
Central CM	A, slag	92.6	32.49	28.50
Partizan CM	A, slag	91.3	33.33	27.39
Mayak CM	ASH	92.6	32.53	28.47
Mayak CM	A, slag	91.2	32.36	28.18
Mean value				28.16
Standard deviation				0.44

Table 3.16. Lean Coal Characteristics

Enterprises	**Type**	C^{daf}	Q_i^{daf}	k_c
		%	MJ/kg	kg/GJ
Komisarivska Mine	TR	88.5	33.66	26.29
Fashivska Mine	TR	89.5	33.47	26.74
Kosior Mine	TR	88.7	33.45	26.52
Ukraina Mine	TR	84.4	32.87	25.68
Nikanor Mine	TR	89.0	34.49	25.80
Zhitomir Mine	TR	91.8	35.09	26.16
Komunarska Mine	TR	90.8	34.25	26.51
Rassvet Mine No 5/7	TR	91.3	34.83	26.21
VZhSR 60 Years 3/4	TR	88.9	34.00	26.15
Pravda Mine No 12/16	TR	87.0	33.78	25.75
Pravda Mine No 20	TR	87.0	33.82	25.72
Krasnaya Zvezda 20	TR	88.4	34.83	25.38
Krasnaya Zvezda 8	TR	85.1	33.45	25.44
Krasny Oktyabr Mine	TR	88.9	34.28	25.93
Olkhovatska Mine	TR	90.5	33.70	26.85
Vergelivska Mine	TR	89.7	34.46	26.03
Annenska Mine	TR	86.0	33.54	25.64
Mospinska CM	T, concentrate	89.9	34.58	26.00
Kindrativska CM	T, concentrate	90.9	34.67	26.22
Mean value				26.05
Standard deviation				0.41

Table 3.17. Low Heating Values and Ash Content on Ukrainian TPP

Power Plant	Coal type	1999		2002	
		Low Heating Value, MJ/kg	Ash Content, %	Low Heating Value, MJ/kg	Ash Content, %
Kryvorizka TPP	L	17.203	40.40	21.227	29.80
Prydniprivska TPP	A	19.623	30.70	22.651	23.00
Zaporizka TPP	G+C	15.866	38.26	19.494	26.96
Slovianska TPP	A	17.668	33.99	21.914	23.08
Starobeshivska TPP	A+L	18.308	35.10	21.344	25.74
Burshtynska TPP	G+C	17.978	28.50	19.033	28.50
Dobrotvirska TPP	G+C	16.546	34.29	20.231	26.97
Ladyzhynska TPP	G+C	13.812	44.60	18.053	26.41
Vuhlehirska TPP	G+C	20.649	25.03	20.503	26.18
Zmiyvska TPP	A+L	18.468	34.90	21.516	24.46
Trypilska TPP	A+L	17.115	37.20	21.181	26.20

A – anthracite, L – lean coal (like semi-anthracite), G – gas coal (like bituminous coal), C – candle coal (like bituminous and sub-bituminous coals)

3.3 Carbon Oxidation Factors

The amount of carbon that may remain unoxidised from combustion activities can vary for many reasons, including type of fuel consumed, type of combustion technology, age of the equipment, and operation and maintenance practices. 1996 Guidelines and 2000 GPG recommend using default assumptions suggested both for the Reference Approach and the Tier 2 approach: 2 per cent of carbon in fuel consumed is unoxidised for coal, 1 per cent for oil-derived fuels, 0.5 per cent for natural gas and 1 per cent for peat used for electricity generation.

Table 3.18. Default IPCC values

FRACTION OF CARBON	OXIDISED
Coal[(a)]	0.98
Oil and Oil Products	0.99
Gas	0.995
Peat for electricity generation[(b)]	0.99

(a)This figure is a global average but varies for different types of coal, and can be as low as 0.91.
(b)The fraction for peat used in households may be much lower.

These assumptions are based on 1984 study [31] and slightly adjusted based on the information from OECD Coal Industry Advisory Board and British Coal (see text box below).

The IPCC Guidelines recognize that either detailed information on the type of technology in which the fuel is combusted or information on which sector is consuming the fuel is required for correct application of the oxidation factors. Therefore, although at the time of compilation of the Guidelines more up-dated information on oxidation factor was available, only approximate estimates were given, and national experts were encouraged to vary this assumption if they had better data. Consequently the experts in Russia, Ukraine, and Kazakhstan made their own assessments of the carbon oxidation factors for their research purposes, which are presented in the subsections 3.3.1-3 below.

- *Marland and Rotty:* For natural gas, less than 1 per cent of the carbon is unoxidised during combustion and remains as soot in the burner, stack, or in the environment. For oil 1.5% ±1% passes through the burners and is deposited in the environment without being oxidised. This estimate is based on 1976 US statistics of emissions of hydrocarbons and total suspended particulates. For coal 1% ±1% of carbon supplied to furnaces is discharged unoxidised, primarily in the ash.
- *Australia:* Unoxidised carbon from electric power stations in Australia averaged about 1 per cent. Test results from stoker-fired industrial boilers, however, were higher, with unoxidised carbon amounting to 1 to 12 per cent of total carbon with coals containing from 8 to 23 per cent ash. As average values, 2 per cent carbon loss was suggested for best practices, 5 per cent carbon loss for average practices, and 10 per cent carbon loss for worst practices. In those cases when coal is used in the commercial or residential sectors, carbon losses would be on the order of 5 to 10 per cent (Summers, 1993).
- *British Coal:* Percentage of unburnt carbon for different coal combustion technologies:

Pulverised Coal	1.6%
Travelling Grate Stoker	2.7-5.4%
Underfeed Stoker	4.0-6.6%
Domestic Open Fire	0.6-1.2%
Shallow Bed AFBC[10]	Up to 4.0%
PFBC/CFBC[10]	3.0%

[10] AFBC = Advanced Fluidised Bed Combustion
CFBC = Circulating Fluidised Bed Combustion
PFBC = Pressurised Fluidised Bed Combustion

- Evaluations at natural gas-fired boiler installations indicate that combustion efficiency is often 99.9 per cent at units reasonably well-maintained.

Source: !996 Revised IPCC Guidelines: Reference Manual

3.3.1 National values: Russia:

When RAO UESR developed its carbon emission factors for its corporate inventory, they discounted their emission factor values to account for the fraction of carbon unoxidized characteristic for their facilities. In this report we separate these two values mostly because on average in Russia fuels are combusted with much lower efficiency than at large electric power plants.

Fuel oxidation factors are rather high at the power plants of RAO UESR. For its inventories RAO UESR has developed internal carbon oxidation factor for coal, which equals 0.984. This value was based on the survey power plants, in accordance with the combustion efficiency they indicate on their internal reporting forms. The interim calculation factor (q_4) was determined only for those power plants which burned only one fuel type, in order to avoid distortions in the calculations. Gas and heavy oil combustion at large power plants is very efficient and fraction of un-oxidized carbon is considered to be negligible. The fraction of unoxidized mazut has also not been studied specifically in Russia - it is assumed that the mazut burned at the power plants is combusted almost entirely. The experts estimate that the fraction of fuel unoxidized is 1% for gas and 0.5% for mazut, which is supported by international data (i.e. IPCC default factors).

Thus the oxidation factors for large power plants are

Gas	0.999
Heating oil (mazut)	0.995
Energy Coal	0.984

According to RAO UES data, fuel other then coal, gas, or mazut is used only at one or two out of 370 large power-plants in Russia.

Because RAO UESR consumes only about 1/3 of the national fuel consumption volume, it is recommended [19] that the IPCC default oxidation factors when carrying out greenhouse gas emission estimation under the Reference Approach. If the technology type is known (as for example for project level GHG emission assessment or for sectoral/entity level emission estimation), [19] gives the oxidation factor for coal combustion in small boilers as 0.91, and for large enterprises (but not power plants) as 0.96, although it is not clear whether this are based on country-specific research or on international estimates.

3.3.2 National values: Ukraine:

The values of carbon oxidation factor have been calculated in [28] using data from the statistical reporting on the quality of fuels consumed (3-tech format). For the enterprises which lack information on heat losses due to combustible losses, the value of combustible loss $q_{4(SF)}$ (see Formula 9) was assumed as it is in [29]. Tables 19 and 20 show local oxidation factors for the dust-and-coal power plants for 1990 and 1999.

IPCC default oxidation factor for all the types of solid fuel is 0.98. From the results of an analysis of working parameters of the boilers in use at the Ukrainian electricity enterprises, the values of the local carbon oxidation factor were found for 1999 to vary from 0.741 (for Luhansk TPP) to 0.997 (for Vuhlehirsk TPP). Because of the lack of information on heat losses for 1990, the values of $q_{4(SF)}$ were taken from the directory [21] that are shown in Table 20.

With coal and mazut or natural gas burned together, the heat losses due to combustible loss $q_{4(SF)}$ are growing [29]. For the boilers with liquid slag removal that burn anthracite or lean coal, the $q_{4(SF)}$ losses are 6.4%. For the boilers with liquid slag removal that burn gas or candle coal, the $q_{4(SF)}$ losses are 0.7%. For the boilers with solid slag removal, combustible loss $q_{4(SF)}$ is 2.4%. This should be considered for finding greenhouse gas emissions from individual power units and TPPs.

Table3. 19. Values of Heat Losses (%) Due to Combustible Loss

Fuels	Slag Removal	
	solid	liquid
Anthracite	6.0	4.0
Lean coal	2.0	1.5
Bituminous coal	1.5	0.5

3.3.3 National values: Kazakhstan

Carbon oxidation factors for crude oil, gasoline, jet kerosene, diesel oil, heating oil, coal, and natural gas used when compiling the national inventories in Kazakhstan were calculated by the Kazakh Scientific Research Institute for the Energy Industry (KazNIPIenergoprom) based ob reference data from thermal power engineering manuals and state standards.

Fraction of carbon oxidized in boiler-houses was determined as a sum of mechanically and chemically incomplete fuel combustion. Coal in Almaty region is mainly combusted in the form of slag in chamber furnaces with dry-ash removal. The value of chemically incomplete combustion for this type of combustion was assumed to be zero. The mechanically incomplete combustion is defined by fuel underburnings left in cinder, fall-through and carryover. According to reference data the fractions of carbon oxidized in coal-slack boiler are:

- 98.5 % for Ekibastuz coal combustion,
- 99.0 % for Karaganda coal combustion.

Table 3.5 in section 3.2.1 contains the reference values that were taken for other types of coal.

For combustion of natural gas and residual fuel oil the fraction of carbon oxidised was determined by chemically incomplete fuel combustion. According to reference data it amounts to 99.5 %.

Table 3.20. Local Carbon Oxidation/Emission Factors for Coal in 1990				
Company, enterprise	***Base Fuel***	***Heat Losses*** $q_{4(SF)}$ %	***Factors*** Oxidation	emiss.t/TJ
Vinnytsyaenergo				
Vibbytsya PTM	G/M			
Ladyzhin TPP	G+D	0.70	0.991	25.19
Khmelnitsky PPEM	G/M			
Chernivtsi OPM	G/M			
Dniproenergo				
Dniprodzerzhinsk CHP	G/M			
Zaporizzhya TPP	G+D,G/M	0.70	0.991	25.19
Kirovograd CHP	G/M			
Kryvy Rih TPP	T+A	2.40	0.972	26.67
Kryvy Rih CHP	G/M			
Prydniprovska TPP	A+T	6.40	0.930	27.38
Donbasenergo				
Vuhlehirsk TPP	G+D,G/M	0.70	0.991	25.19
Donbasenergo ERP	G/M			
Zuyiv TPP-2	G+D	0.70	0.991	25.19
Kramatorsk CHP	A	6.40	0.930	28.16
Kurakhiv TPP	G+D	2.10	0.974	25.19
Lisichansk CHP	G/M			
Luhansk CHP	A+T	6.40	0.930	27.38
Myronivka TPP	A+T	6.40	0.930	27.38
Myronivka TPP	G+D	0.70	0.991	25.19
Severodonets CHP	G/M			
Slovyansk TPP	A, G/M	6.40	0.930	28.16
Starobeshiv TPP	A+T	6.40	0.930	27.38
Kyivenergo				
Bila Tserkva CHP	G/M			
Darnitsa CHP	A, G/M	6.40	0.930	28.16
Zhitomir PEM	G/M			
Kyiv PTM	G/M			
Kyiv CHP-5	G/M			
Kyiv CHP-6	GM			
Trypillya TPP	A, G/M	6.40	0.930	28.16
Uman PEM	G/M			
Cherkasy CHP	G+D,G/M	0.70	0.991	25.19
Chernihiv CHP	A, G/M	6.40	0.930	28.16
Krymenergo				
Kamysh-Burun CHP	A	6.40	0.930	28.16
Saki PTM	G/M			
Sevastopol CHP	G/M			
Simferopol CHP	G/M			
Lvivenergo				
Burshtyn TPP	G+D	0.70	0.991	25.19
Dobrotvir TPP	G+D	2.10	0.974	25.19
Transcarpathian OPEM	G/M			
Ivano-Frankivsk OPEM	G/M			
Kalush CHP	G+D	0.70	0.991	25.19
Lviv PTM	G/M			
Lviv CHP-2	G/M			
Odesaenergo				
Mykolaiv CHP	A	6.40	0.930	28.16
Odesa CHP	G/M			
Odesa PTM	G/M			
Kherson PTM	G/M			
Kharkivenergo				
Zmiyiv TPP	A+T	6.40	0.930	27.95
Kremenchuk CHP	G/M			
Okhtyrka PTM-2	G/M			
Poltave PEM Pivdenne	G/M			
Sumy PTM	A, G/M	6.40	0.930	28.16
Kharkiv TPP-2	A	6.40	0.930	28.16
Kharkiv CHP-5	G/M			
Kharkiv PTM	G/M			

Table 3.21. Local Carbon Oxidation/Emission Factors for Coal in 1999				
Company, enterprise	***Base Fuel***	***Heat Losses*** $q_{4(SF)}$%	***Factors*** oxidation	emiss.t/TJ
Dniproenergo				
Zaporizzhya TPP	G+D	0.78	0.990	25.19
Kryvy Rih TPP	T+A	5.82	0.933	26.67
Prydniprovska TPP	A+T	10.33	0.887	27.38
Donbasenergo				
Zuyiv TPP	G+D	0.72	0.991	25.19
Kurakhiv TPP	G+D	3.22	0.961	25.19
Luhansk TPP	A+T	23.62	0.741	27.38
Slovyansk TPP	A+T	8.52	0.907	27.38
Starobeshiv TPP	A+T	7.53	0.918	27.38
Zakhidenergo				
Burshtyn TPP	G+D	1.41	0.983	25.19
Dobrotvir TPP	G+D	2.25	0.973	25.19
Ladyzhin TPP	G+D	1.24	0.985	25.19
Tsentrenergo				
Vuhlehirsk TPP	G+D	0.25	0.997	25.19
Zmiyiv TPP	A+T	10.58	0.884	27.38
Trypillya TPP	A+T	17.35	0.810	27.38
Vinnytsyaoblenergo				
Vinnytsya PTM	G/M			
Donetskoblenergo				
Myronivka TPP	G+D	0.70	0.991	25.19
Zakarpattyaoblenergo				
Transkarpathian OPEM	G/M			
Kyivenergo				
Kyiv CHP-5	G/M			
Kyiv CHP-6	G/M			
Kyiv Boiler Houses	G/M			
Krymenergo				
Kamysh-Burun CHP	A+T	4.80	0.948	28.16
Crimean NPP Boiler	G/M			
Saki Heat Networks	G/M			
Saki Boiler Houses	G/M			
Simferopol CHP	G/M			
Odesaoblenergo				
Odesa PTM	G/M			
Poltavaoblenergo				
Kremenchuk CHP	G/M			
Poltava PEM Pivdenne	G/M			
Prykarpattyaoblenergo				
Ivano-Frankivsk OPEM	G/M			
Sevastopolmiskenergo				
Sevastopol CHP	G/M			
Cherkasyoblenergo				
Chigiryn PS	G/M			
Uman CHP	G/M			
Chernivtsioblenergo				
Chernivtsi PEM	G/M			
Others				
Dniprodzerzhinsk CHP	G/M			
ESKHAR (CHP-2)	G/M			
Kryvy Rih CHP	G/M			
Lisichansk CHP	G/M			
Mykolaiv CHP	G/M			
Odesa CHP	G/M			
Severodonetsk CHP	G/M			
Kharkiv CHP-5	G/M			
Kharkiv Heat Networks	G/M			
Kherson CHP	G/M			
Cherkasy CHP	G+D	0.98	0.988	25.19

3.4 EMISSIONS FROM COKE GAS COMBUSTION

GHG emissions from coke gas combustion were examined in detail in a single pilot study in Ukraine [32]. It was carried out at *ZaporizhKoks* coking plant in the city of Zaporizhzhia, Ukriane as part of the outreach and capacity building activities of Canada-Ukraine Environmental Cooperation Program. The study estimated plant's CO2 emissions in 2000 and estimated process emission factors. Emission factors were estimated using three methods: IPCC methodology, methods based on standards and direct measurements.

Table 3.22. Comparison between IPCC, Ukrainian state standard, and measured emission factors.

Method	Emission factor, t C /TJ	Deviation from default emission factor, %
IPCC[9]	13	0
Standards	12.73	-2
Measurements	13.63	5

The Zaporozhye Coke Plant includes several process sections: coal preparation, coking, by-product recovery, benzene production, de-sulfurization, sodium rodanite production, tar extraction, coke furnaces. Four coke ovens batteries and 14 coke ovens make up the core of Zaporizhkoks production capacity. Besides, there are several facilities that are not directly involve in the manufacturing process but which ensure the operation of the plant.

The coking at the plant is produced by heating fine dispersed[10] coal batch to 950-1050^{o}C at chamber-type ovens in the absence of oxygen. The time between loading and discharge of coke is usually between 16 and 22 hours. The process results in the release of 320 to 340 m^3 of coking gas per tonne of coal mix.

Table 3.23. The characteristics of Zaporizhkoks coke oven batteries

Coke oven battery number	Start of the operation	Volume of the chamber, m^3	Heating system	Number of ovens	Dimensions of the coking chamber, m
1-bis	1980	41.6	bottom	65	16x7x4.1
2-bis	1982	41.6	bottom	65	16x7x4.1
5	1983	21.6	side	61	14x4.3x4.1
6	1984	21.6	side	61	14x4.3x4.1

After cooling and purification, the coke oven gas is transported to heat the coke ovens and to be used at other plant facilities. Coke ovens consume up to 50 % of the coke oven gas produced at the plant. Other facilities that use the gas (1 to 4 %) include coke furnaces, tar extraction, benzene production, sulfur production, repair shop, and coal defrosting facility. The latter consumes up 1 % of the coke oven gas in the winter period.

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[9] CORINAIR emission factor for coke oven gas combustion in coke oven furnaces 42-56 g/GJ (based on CORINAIR 90 data).
From 1996 IPCC guidelines, for coke oven gas net calorific value 37.5 GJ/t (background paper), 17.5 MJ/m^3, emission factor 13 tC/TJ (IPCC), 11 (background paper).
From GPG coke oven gas Net Calorific value for Ukraine is 25.12.

[10] 75-80 % fraction smaller than 3 mm

Table 3.24. Composition of raw coke oven gas

Components of coke oven gas	Concentration [Vol.-%] Winnacker 1982, from CORINAIR	Ukrainian study
H_2	58 - 65	57.6
CH_4	24 - 29	25.3
CO	4.6 - 6.8	6.8
C_nH_m	2 - 4	2.3
CO_2	1.5 - 2.5	2.5
N_2		4.5
O_2		1.2

Emissions during coking operations are caused by the charging of the coal into the ovens, the oven/door leakage during the coking period, and by pushing the coke out of the ovens. Gas combustion in the flues between the ovens, which produces the heat, necessary for the coking process, is the major source of greenhouse gas emissions.

At the ZaporizhKoks facility, GHG emissions from a number of the sources at the facilty's coke plant were analyzed on several levels. GHG emissions during coke manufacturing can be distinguished into continuous or controlled sources and discontinuous or uncontrolled sources (see text box below). "Controlled" emissions of GHG occur when coke oven gas is combusted for various purposes during the manufacturing process. Estimation of missions from these sources is rather simple, as it is possible to both measure and calculate GHG emissions with sufficient accuracy. The main and continuous sources of GHG emissions in coke manufacturing are stacks (ascension pipes) that remove the flue gases formed during the combustion of coke oven gas. In addition to coke oven batteries, coke oven gas at ZaporizhKoks is combusted at: benzene production, coke furnaces, defrost facility (in the winter), ammonium sulphate drying, forge shop, flaring of access gas.

The basic sources of uncontrolled GHG emissions to atmosphere are the coke oven batteries. During one hour there are 4 to 6 operations of charging and discharging the ovens, during which there are inevitable escapes of GHG gases. Sources of such uncontrolled emissions at the coke plant include by the charging of the coal into the ovens, coke discharging, coke quenching, leakage at the doors, pouring gates, and coke ramp. Estimation of GHG emission from uncontrolled sources is more complicated, since it is determined by particular conditions of the plant components, i.e. a composition of the coal mixture, technological parameters of the manufacturing process, duration and conditions of the operation of the equipment and other specific characteristic. The GHG emissions from uncontrolled sources are periodical and their volumes are considerably less than that from the controlled sources.

Continuous emissions:	*Discontinuous emissions:*
Emissions from storage and handling of raw materials and products	Oven charging
Oven door and frame seal leakage	Coke pushing
Ascension pipe leakage	Coke cooling
Charging holes leakage	
Coke oven firing	
Vent systems in gas treatment plant	
Desulphurisation plant	

Methodology

The emissions were calculated with three methods:

- Calorific balance method as stipulated by the State Standard (normative method);
- IPCC methodology
- Direct measurement

Standard methodology

The normative method establishes the mass of fuel combustion products combustion of fuel of given composition, in this case the coke oven gas:

$$M_{CO_2} = 10^4 \cdot V_a \cdot V_0 \cdot V_{CO_2} \cdot \rho_{CO_2} \cdot 10^{-9}, \qquad (11)$$

where

V_a - annual volume of combusted coke oven gas, thousand m^3,

V_0 - volume of dry combustion products from combustion of 1 m^3 of coke oven gas, equals 3.9 nm^3/nm^3 (when excess air coefficient is equal to 1),

V_{CO_2} - maximum concentration of CO_2 in combustion products, 10.5 %,

ρ_{CO_2} - CO_2 density, 1,96 kg/m^3,

10^4 - conversion factor from parts to mg,

10^{-9} - conversion factor from mg to tonnes.

IPCC methodology

The calorific value of the fuel in 2000 varied from 3950 to 4239 $Kcal/m^3$ (according the Zaporizhkoks JSC data). For the purposes of study, an average value of 4100 $Kcal/m^3$ was assumed. Default emission factor of 13 tC/TJ was used.

Instrumental measurements

The measurements of the GHG emissions were carried out with the use of different methods and equipment, such as: the gas composition analysers «Testo-33», «Testo-350» (Germany), ENERAC (USA), in which electrochemical cells are used as sensors. Measurement error for $O_2(CO_2)$ is ±0.2 %. Additionally, traditional analytical measurements were performed (gas chromatography and chemical method). Gas sampling was carried out in accordance with the procedures prescribed by the State Standards (ГОСТ). The samples were taken during the normal operating cycle of the equipment and with average coking period. The number of consecutive samples taken from each source with each device was not less than five. The simultaneity of taking measurements by different methods was ensured. The samples were collected over a period of not less than 20 minutes. The results of the measurements were averaged for each of the samples and further averaged for each of the analytical devices.

CO_2 emissions were calculated based on the measurements of in-situ concentrations of in the flue gas. For continuous emission sources, CO_2 emissions were estimated in relation to the annual consumption of coke gas by plant. For discontinuous emission sources, cumulative emission time per year was estimated; CO_2 emissions were determined in relation to in-situ CO_2 concentration in the flue gas and per-second flue gas emissions from the source. The following formulas were applied:

Continuous emission sources:

$$M_{CO_2} = 10 \cdot V_{CO_2}^{ms} \cdot \rho \cdot \alpha \cdot K_T \cdot V_0 \cdot V_a \cdot 10^{-3} \qquad (12)$$

$V_{CO_2}^{ms}$ - measured concentration of CO_2 in combustion products, %,

ρ_{CO_2} - CO_2 density, 1,96 kg/m^3,

α - access air factor, equals 1 under standard conditions,

K_T - temperature coefficient

V_0 - volume of dry combustion products from combustion of 1 m^3 of coke oven gas, equals 3.9 nm^3/nm^3 (when excess air coefficient is equal to 1),

V_a - annual volume of combusted coke oven gas, thousand m^3,

Discontinuous emission sources

$$M_{CO_2} = 10^4 \cdot V_{CO_2}^{ms} \cdot \rho \cdot W \cdot T \cdot 3600 \cdot 10^{-9} \qquad (13)$$

M_{CO_2} - mass of emitted CO_2

$V_{CO_2}^{ms}$ - measured concentration of CO_2 in combustion products, %,

ρ_{CO_2} - CO_2 density, 1,96 kg/m^3,

α - access air factor, equals 1 under standard conditions,

W - spending of air-gas mixture,

T - time,

10^4 - conversion factor from parts to mg,

10^{-9} - conversion factor from mg to tonnes.

Table 3.25. Comparison of results for 3 methods for each estimated source

Source of emission	CO_2 Emissions		
	Normative method, thousand t	IPCC, $GgCO_2$	Measurement
Coke oven battery #1-bis, stack	110.3	112.49	115.3
Coke oven battery #2-bis, stack	126.65	129.07	131.9
Coke oven battery #5, stack	66.9	68.2	75.2
Coke oven battery #6, stack	67.3	68.79	73.2
Pitch coke battery, stack	14.8	15.03	16.3
Tar extractor, stack	13.1	13.31	14.3
Defrosting facility, stack	6.3	6.34	6.9
Benzene production, stack	25.17	25.63	29.2
Sulfate production, stack	3.06	3.15	3.7
Forge shop, stack	3.1	3.52	3.9
Gas release rig	34.4	35.13	34.4 (calc.)
Total	471.5	480.7	504.3

As can be seen from the table above, measured CO_2 emissions exceeded calculated estimations by 5 to 7 %, and for certain sources by up to 12.5 %. Taking into account actual fluctuations in the composition of the coke gas, CO_2 emissions exceeded calculated estimations by as much as 22 %.

CO2 emissions from coke oven gas combustion and estimated emission factors are summarized in Tables 3.26 and 3.27.

Table 3.26. Coke oven gas combustion and estimated emission factors at ZaporizhKoks plant

	Unit	Coke oven battery #1-bis	Coke oven battery #2-bis	Coke oven battery #5	Coke oven battery # 6	Total
Fuel consumption	ths m^3/year	137520	157741	83360	84079	462700
Coke produced	t/year	629775	723896	405572	404970,9	2164213,
Coke gas produced	ths m^3/year	918850				9932045*
Gas delivered to consumers	ths m^3/year					344566
CO_2 emissions	t/year	116039	132795,5	75659,2	73652,3	398146
Emission factor	tCO2/t of coke	0.184	0.183	0.186	0.181	0.184

*including pitch coke battery

Table 3.27. Coke oven gas combustion and estimated emission factors at ZaporizhKoks plant

Parameter	Unit	Pitch coke battery	Tar extractor	Defrosting facility	Benzene production	Ammonium sulfate drying	Repair shop	Gas release rig
Consumption of fuel	thous. m^3/year	18382	16255	7752	31322	3835	4292	42941
Product output	t/year	43908	95760	-	32470	8805,5	-	-
Coke gas produced	thous. m^3/year	13195						
Gas delivered to consumers	thous. m^3/year							
Emission of CO2	t/year	16300	14300	6900	29200	3700	3900	34400
Specific emission of CO_2 per unit of product	t.CO2/t.product.	0.37	0.15		0.9	0.42		

The study presents analysis of CO_2 emissions from coke oven gas combustion at one coking facility. It is not clear what conditions at other Ukrainian coke producers are and whether the conditions described at this plant are representative for the Ukrainian coking industry. Literature [18] indicates that emissions decrease with the increase of the size of the ovens, as large ovens increase batch size and reduce the number of chargings and pushings, thereby reducing associated emissions. Emissions are also reduced by constant coking conditions, cleaning, and a low-leakage door construction e. g. with gas sealings. Therefore more research is needed on the prevailing coking technology in Ukraine and likely emissions if they have been estimated. It would be also recommendable to estimate emissions of other pollutants from coke ovens, particularly CO, CH_4, NO_x, N_2O, NMVOC.

4 CO_2 EMISSIONS FROM MOBILE COMBUSTION OF FOSSIL FUELS

Only one country undertook a detailed analysis of CO_2 emissions from mobile sources. Kazakhstan as part of the regional GHG inventory project in Almaty region conducted analysis of GHG emissions from the transportation sector, which among other included analysis of carbon emission factors from fossil fuels used in vehicles in Kazakhstan.

Table 4.1 presents emission factors and other parameters used to convert combusted fuel into CO_2 emissions for this inventory. They were estimated by experts from "KazNIPIenergoprom" and the Kazakh Research Designing Institute of Energy Industry for gasoline, diesel, liquefied petroleum gas (LPG), and compressed national gas (CNG) using following information:

- state standards for different fuel types,
- statistical data,
- data on several oil and gas deposits.

Table 4.1. Factors for CO_2 emissions estimation from road transport

Fuel type	**Net calorific value, TJ/unit**	**Carbon emission factor, t C/TJ**	**Fraction of carbon oxidized**
Gasoline	44.21	19.13	0.995
Diesel	43.02	19.98	0.995
LPG	47.17	17.91	0.99
CNG	34.25	15.03	0.995

Emission factors for non-CO2 gases were calculated for different vehicle types and fuel types based on *Russian Guidelines for estimation of road transport emissions to be used in calculation of city air pollution* [35]. Division of the fleet by types of vehicles were made by experts from the Transport Research Institute that take into account recommendations from the IPCC Guidelines:

Passenger cars	vehicles with rated gross weight less than 3500 kg designed to carry 12 or fewer passengers
Light-duty trucks and minibuses	vehicles with rated gross weight less than 3500 kg designed for transportation of cargo or up to 16 passengers or which are equipped with special features for off-road operation. They include most pickup trucks, passenger and cargo vans, four-wheel drive vehicles, and derivatives of these
Heavy-duty trucks	manufacturer's gross vehicle weight rating exceeding 3500 kg. These include large pickups, vans and trucks using pickup and van chassis, as well as large heavy-duty trucks, which have gross vehicle weights more than 7 tons
Buses	all buses except minibuses

The road fleet was not divided by the emission control technology type as all vehicles were assumed to have no emissions controls. In support of this assumption, the share of vehicles equipped with emission control technologies is negligible. Additionally, these vehicles are currently not separately registered in statistics. Table 2.9 presents the calculated emission factors for non-CO2 gases. N2O emissions factors were taken from the IPCC Guidelines as default.

Table 4.2: Emission factors for CO_2 and non-CO_2 gases (CH_4, N_2O, CO, NO_x, NMVOC) from road transport in Kazakhstan

Units			**Emission factors**				
	NOx	**CH_4**	**NMVOC**	**CO**	**N_2O**	**CO_2**	**SO_2**
Gasoline passenger cars							
g/km	1.80	0.023	2.1	19		291.56	0.187
g/kg of fuel	19.23	1.25	22.44	203		3115	2
g/MJ	0.439	0.006	0.512	4.636	0.1	71.13	0.046
Diesel passenger cars							
g/km	1.30	0.022	0.25	2		281.56	0.891
g/kg of fuel	14.59	1.25	2.81	22.4		3160	10
g/MJ	0.342	0.006	0.066	0.527	0.6	74.14	0.235
Light-duty gasoline trucks and minibuses							
g/km	2.90	0.047	11.5	69.4		583.13	0.374
g/kg of fuel	15.49	1.25	61.43	370.7		3115	2
g/MJ	0.354	0.006	1.403	8.466	0.1	71.13	0.046
Heavy-duty gasoline trucks							
g/km	5.20	0.05	13.4	75		627.98	0.403
g/kg of fuel	25.79	1.25	66.47	372.0		3115	2
g/MJ	0.589	0.006	1.518	8.496	0.1	71.13	0.046
Heavy-duty diesel trucks							
g/km	7.70	0.071	6	8.5		895.86	2.835
g/kg of fuel	27.16	1.25	21.16	30.0		3160	10
g/MJ	0.637	0.006	0.497	0.703	0.6	74.14	0.235
Heavy-duty LPG trucks							
g/km	2.6	0.047	1.3	39		414.43	0
g/kg of fuel	16.76	1.25	8.38	251.5		2672	0
g/MJ	0.345	0.006	0.173	5.179	0.6	55.04	0
Gasoline buses							
g/km	5.3	0.065	13.4	97.6		807.41	0.518
g/kg of fuel	20.45	1.25	51.70	376.5		3115	2
g/MJ	0.467	0.006	1.181	8.599	0.1	71.13	0.046
Diesel buses							
g/km	8	0.073	6.5	8.8		921.46	2.916
g/kg of fuel	27.43	1.25	22.29	30.2		3160	10
g/MJ	0.644	0.006	0.523	0.708	0.6	74.14	0.235

5 FUGITIVE EMISSIONS FROM GAS SYSTEMS

Fugitive emissions from gas systems were systematically estimated mostly only in Russia. There are four studies that estimate fugitive emissions from gas systems in Russia:

1. Two governmental studies – the Second National Communication and the Russian Federation Climate Change Country Study.
2. A study conducted by Gazprom and EPA that provides estimates of methane emissions from compressor stations (Methane Leak Management at Selected Natural Gas Pipelines Compressor Stations in Russia, referenced in [36])
3. A study conducted by Gazprom and Ruhrgas that provides estimates for all segments that Gazprom controls – "Estimating Methane Releases from Natural Gas Production and Transmission in Russia" (Rurhgas and Gazprom study [37]).

The Second National Communication and the Russian Federation Climate Change Country Study present estimates for the whole natural gas sector. In 1996-1997, under the U.S. Country Studies Program and with assistance from the United States, Russia prepared a 6-volume report about Russia's climate change mitigation and adaptation policies – the Russian Federation Climate Change Country Study, published by Russian Federal Service for Hydrometereology and Environmental Monitoring in 1997. The Country Study also provides information about GHG emissions, including methane emissions from the natural gas sector. The Country Study is the foundation for all government documents about climate change mitigation policies in Russia. Most of the information for the National Communications was collected under the Country Study. Because of budget constraints, the same small group of experts participated in preparing the Country Study and the National Communications. The Second National Communication (SNC) repeats the results of the first one and, therefore, this report describes only the SNC (Interagency Commission of the Russian Federation on Climate Change 1998).

EPA and Gazprom conducted a number of measurements in preparation for implementing a larger project under a GEF grant. EPA and Gazprom introduced more detailed methods of estimating emissions and began developing activity and emission factors. Their measurements cover only a small number of components. At the same time, the study provided accurate component counts and described the methodology it used.

Ruhrgas and Gazprom conducted measurements at compressor stations, pipelines, and gas processing plants. They extrapolated results to the whole natural gas sector. Gazprom and Ruhrgas do not provide detailed descriptions of the components covered and do not develop any activity or emission factors. Although their estimates of leaks from compressor stations are close to EPA and Gazprom estimates, more information is needed to understand how Ruhrgas and Gazprom derived these results. The uncertainty of results is also very high.

None of the studies presents statistical estimates of uncertainties, thus methane emissions estimates are evaluated to have +/- 50 percent certainty: More measurements should be conducted to come up with solid numbers concerning uncertainties.

Table 5.1. CH_4 Emission Estimates from Different Segments of the Russian Natural Gas Sector

<table>
<tr><td rowspan="4"></td><td colspan="2">1990
Country Study</td><td>1995
Gazprom/EPA</td><td colspan="4">1997
Gazprom/Ruhrgas</td></tr>
<tr><td rowspan="3">Production (includes maintenance and flaring)</td><td rowspan="3">Processing Storage Transmission Distribution</td><td rowspan="3">Transmission Compressor Stations Leaks Only</td><td rowspan="3">Production and processing</td><td colspan="3">Transmission</td></tr>
<tr><td rowspan="2">Pipe-lines</td><td colspan="2">Compressor stations</td></tr>
<tr><td>Intentional</td><td>Leaks</td></tr>
<tr><td>Emissions (million tones CH_4)</td><td>3.1 - 7.5</td><td>6.2 - 13.6</td><td>1.48</td><td>0.22</td><td>0.85</td><td>0.74 - 1.2</td><td>1.6</td></tr>
<tr><td>Emissions (billion m^3)</td><td>4.19 - 10.13</td><td>8.37- 18.36</td><td>2</td><td>0.3</td><td>1.15</td><td>1 - 1.6</td><td>2.1</td></tr>
<tr><td>Gas production (billion m^3)</td><td colspan="2">589.5</td><td>559.5</td><td>540</td><td></td><td></td><td></td></tr>
<tr><td>% from production</td><td>0.71 - 1.72</td><td>1.42 - 3.11</td><td>0.36</td><td>0.06</td><td>0.21</td><td>0.57 – 0.69</td><td></td></tr>
</table>

Sources: Russian Federal Service for Hydrometereology and Environmental Monitoring (1997b); [37]

Table 5.2. Methane Emissions from the Whole Russian Sector

	1990		**1994**		**1997**
	SNC	**CS**	**SNC**	**CS**	**Ruhrgas/ Gazprom**
Emissions (million tones CH_4)	16.0	16.0	15.2	11.5	4
Emissions (billion m^3)	21.6	21.6	20.5	15.5	5.4
Gas production (billion m^3)	589.5	589.5	570.5	570.5	540
% from gas production	3.7	3.7	3.6	2.7	1

SNC – The Second National Communication; CS – Country Study

6 FUGITIVE EMISSIONS FROM COAL MINING ACTIVITIES

Research into coal mining and coal bed methane emissions in Russia has been supported mostly through the international activities of the Coalbed Methane Outreach Program of the US Environmental Protection Agency. Although relevant activities were conducted in all three countries, this report presents only the results of the activities conducted in Ukraine and Kazakhstan, as the results of research carried out in Russia were not available at the time of preparation of this report.

6.1 IPCC Methodology

The general methodology for estimating methane emissions from coal-mining activities is based on the accounting for all methane releases triggered by human activities during the coal fuel cycle from the point of extraction to the point of utilization. Thus IPCC Guidelines stipulate that methane emission estimates in the category of fugitive emissions from coal mining and handling should be developed for three principal sources of methane emissions: underground mines, surface mines, and post-mining activities:

Total emissions = Emissions from underground mining
+ Emissions from surface mines
+ Post-mining emissions
- Utilized and flared methane

The IPCC methodology describes three levels (Tiers 1-3) of precision in estimating fugitive emissions from coal-mining activities. For Tiers 1 and 2 the estimation is made based on the coal production data and a default global average (Tier 1) or national/regional (Tier 2) emission factor. For the emissions from underground mining activities in the Former Soviet Union region, IPCC recommends global average emission factors of 17.8 – 22.2 m^3/tonne. The estimation under Tier 3 is made based on the actual emission information obtained based on the measurements in the mines.

However, since emission factors can vary significantly from basin to basin and even from coal seam to coal seam depending on coal and geological characteristics,[11] it is suggested that countries estimate their national EF based on the coal characteristics in their coal-mining regions. It is also recommended therefore that a database of relevant emission factors is established to help other countries find matching mining conditions. In this section

[11] Coal ranks - a measure of the degree of coalification (depends on geological history), higher rank coals tend to have greater adsorptive capacities and therefore contain more gas.

Mining methods - there are two main underground mining methods: room and pillar and longwall mining. The longwall process causes more caving and fracturing in the roof strata above the coal seam that was mined than the room and pillar method. Correspondingly, greater volumes of methane are released per tonne of coal.

Permeability and diffusion rate - influence how quickly the gas can migrate through the coal and into mine workings. After the coal is mined utilizing the longwall method of extraction, the strata overlying the mined coal caves in, causing a formation of highly fractured area, which increases the permeability of the methane containing strata and facilitates the release of methane, we would try to suggest Tier 2 country-specific emission factors for Ukraine and Kazakhstan based on the Tier 3 emission information. According to the Reference Manual of the 1996 Revised IPCC Guidelines, both countries are among the 10 leading producers of coal in the world.

6.2 UKRAINE

The inventories of fugitive emissions from coal-mining related activities were developed for 1990-2001 with the assistance from the US EPA, and with the support of the Ministry of Fuel and Energy of Ukraine, The Ministry of Labor Safety and Social Policy of Ukraine, Makeyevka Mine Safety Institute, coal mine associations, and independent coal mines. A separate study was carried out in 2002 by the Donetsk Expert and Technical Center of the Gosnadzorohrantruda (State Committee on Labor Safety) to quantify methane emissions from the coal during post-mining activities. [ ]

Ukraine has two major coal basins: the Donetsk Basin and the Lviv-Volyn Basin. These basins contain both bituminous and sub-bituminous coal resources. The Donetsk Basin in the East of the country is Ukraine's largest coal reserve, with a correspondingly large number of mines. The Lviv-Volyn Basin, located in the western part of Ukraine, currently has only 14 active mines, all of which are underground. As of January 1, 2002, there were 286 mines in Ukraine,[12] of them only 184 mines had industrial capacity and only 177 mines (underground and surface) produced coal in 2001.

Over 93.4% of the industrial coal reserves in Ukraine come from the depth of above 1,200 m depth, and 57% from above 600 m. The average depth of mining in Ukraine is currently 585 m. Approximately 44% of the mines are working at the depth over 600 m and produce about 40% of the overall coal production. More than 21% of the mines are deeper than 900 m, and some mines are deeper than 1,200 m. The raw coal ash content of the produced coal is 37.2% on average through the coal industry. It varies from 20% to 54% at particular mines. The moisture content of the raw coal is from 4% to 8%. The temperature at the mine operating level can reach 42–52°C. The temperature of the rock strata is estimated to be growing every year by 0.1–1.0°C due to the increasing depth of mining. All underground coal mines in Ukraine use the longwall method of mining.

There are currently only three active surface mines in Ukraine and all of them are located in the western part of the Donetsk Basin. These surface mines produce peat, lignite, and sub-bituminous coals that have low methane content.

6.2.1 Underground mining

All Ukraine underground coal mines are required to monitor the methane concentrations in the air at various locations in the mine workings. They are also required to measure the methane content of the coal being mined. If the methane content of coal exceeds $5m^3$ per tonne, the mine is categorizes as gassy and is obligated to report methane-related data to the regional departments of the Ministry of Labor Safety and Social Policy of Ukraine. Other indicators for the determination of reporting include concentration of methane and particulates in the mining areas, historical frequency of methane outbursts, and various other factors. For different purposes, methane data are also reported to the mining associations and

[12] organized in 174 administrative units that include 48 structural units including 18 state holding companies, 7 production associations, and 22 independent mines.

the regional inspectorates of the Ministry of Ecology and Natural Resources. The methane emissions reported by the mines include the data on the methane contained in the exhaust ventilation air, the methane liberated by the mine degasification systems, as well as the amount of utilized methane.

Methane Emissions from Gassy Mines

The majority of Ukrainian mines are categorized as gassy. At some mines, the natural gas content of the coal seams can exceed 35 m^3 per tonne of dry ash free coal.[13] There are several different technological processes designed to remove methane from the underground mining areas. These processes are the main source of methane emissions from underground mines and include ventilation systems and several degasification techniques. Methane measurements are performed in both degasification and ventilation systems. Direct measurements are applied to monitor two factors: methane concentration and gas mixture flow rate. On the basis of these measurements, the total amount of emissions is calculated.

185 Ukrainian mines reported their methane emissions in 2000. This number also includes the mines in the different phases of closure process, which continue their reporting until physical closure.

Ventilation Systems. Underground ventilation systems are installed in the mines for safety reasons and consist of large fans that blow fresh air from the surface through the working areas of a mine and remove the methane. The device used to measure methane content in the ventilation air of Ukrainian mines is a model AMT-3 automatic metering system. It includes a methane sensor, an alarm unit, a signal transmission system, and plotters. Should methane content exceed the allowed limit, the alarm unit, which is installed in mine workings, emits an electric impulse, cutting power supply to the mine working area. The plotters continuously indicate volumetric percentage of methane in the air. The methane sensor is based on the thermocatalytic principle. The metering range is 0 to 25 percent, with a margin of error of 0.2 percent and a time lag of 60 seconds. Additional methane content analyses are performed by taking mine air samples and measuring the methane concentration in a laboratory.

Degasification Systems. Mine degasification or drainage systems drain the gas from coal seams before, during, and after mining, depending on the particular needs of the mine. There are three types of degasification techniques: vertical wells drilled from the surface, underground horizontal boreholes drilled along the mined coal seam, and cross-measure boreholes drilled through the coal seam and surrounding rock. Cross-measure boreholes are most common in Ukrainian mines. They are used to degasify the overlying and underlying strata of the mined coal seam. Cross-measure boreholes often produce gas with methane content between 30 and 80 percent and their drainage efficiency averages 20 percent. Additionally horizontal boreholes (typically 30 to 50 meters long) are drilled inside the mine to drain methane from unmined areas of blocked-out longwall panels. Degasification wells and boreholes are linked to a centralized vacuum pump or a compressor station by a system of connected pipelines. Since mines operate at very deep levels in Ukraine and have little funds

[13] For the year 2000, the coal production from mines classified as gassy represented 82.4% of the total underground coal production as compared to 69.6% in 1999. The significant increases in both total coal production and CMM emissions are due to the increase in the number of mines classified as gassy. In 1999, there were 164 gassy mines compared with 185 gassy mines in 2000.

to properly maintain their facilities, the drainage system often has multiple leakage points, resulting in lower methane content in the gas stream.

To measure methane concentration in gas-air mixture captured by the degasification system, Ukrainian underground mines employ model TP-2301 or GIAM-14 automatic gas analyzers at the vacuum pump stations. The first analyzer meters the thermal conductivity variation, and the second analyzer meters the optical density of the gas. Continuous readings are plotted in the range of 0 to 100 percent. If methane concentration drops below a set limit (typically 35%), an alarm signal is initiated to automatically shut off the gas supply to the consumer. The metering error is less than ±5 percent for a TP-2301 analyzer, and ±2 percent for a GIAM-14 analyzer. The gas flow rate is calculated on the basis of the pressure difference on diaphragms installed in the degasification system pipelines. Differential manometers are calibrated to indicate the flow rate in cubic meters per hour, while other flow meters are used to measure the pressure difference. Alternatively, ShI-12 portable interferometers are used to measure methane content in mine workings by taking air samples by hand.

Methane Emissions from Non-Gassy Mines

Between 1990 and 2000, 18 to 32 percent of Ukrainian mines did not exceed safety standards and therefore were not required to report the emissions data. For the purposes of this inventory, a conservative approach based on the safety limit of the coal methane content was used to estimate methane emissions from these mines, which is consistent with IPCC Good Practice Guidelines. The maximum allowable methane content by the Ukrainian safety standard is 5 m^3 per tonne. Based on this, emissions factor of 3.4 kg of CH_4 per tonne of coal produced was derived. Since the mines have incentive to inflate the concentrations of methane measured to be classified as gassy (i.e. dangerous), this estimate is strongly on the conservative side.

6.2.2 Surface mining

There are currently six surface mines in the western section of the Donbass Basin. Only three mines, which mine brown coal, are active. The other three mines are in the process of closure and produce only small amounts of coal (two to three thousand tonnes per year) for local needs. The coal produced by the surface mines is of a low rank that has minor methane content; consequently, the mines do not report their methane emissions. In order to determine methane emissions from surface mines, based on expert estimates and taking into account the range of 0.3 to 2.0 m^3/tonne recommended in 1996 IPCC Guidelines, an emission factor of 1.4 m^3/tonne (0.938 kg/tonne) was applied.[14]

6.2.3 Post-Mining Emissions

Post-mining activities such as processing, storage, and transportation also produce methane emissions; however, these emissions are not reported. Therefore, a separate study was carried out in 2001 by the Donetsk Expert and Technical Center of the Gosnadzorohrantruda (State Committee on Labor Safety) to estimate Ukraine methane emissions from post-mining activities in Ukraine. The methane emissions from coal after mining by each particular mine were calculated taking into account the following factors:

[14] Good Practice Guidance recommends applying a conservative value of 1.5 m^3/tonne.

$$I_e = f\,(A_m\ X_n\ X_r;\ T_s\ T_u\ W\ A^C\ H\ H_0\ V^{daf}),\ \text{where}$$

I_e - methane emissions, m^3; A_m - amount of coal delivered to the surface, t; X_n - natural gas content of the coal seam, m^3/t dry and ash free; X_r - remaining gas content of the coal, m^3/t daf; T_s - storage time of coal on the surface after mining, days (minutes); T_u - storage underground after mining, hours; W - coal moisture, before cleaning, %; A^C - coal ash content, before cleaning, %; H - depth of mining, m; H_0 - depth of the upper level of methane gas zone, m; V^{daf}- volatility, %.

The amount of methane released from the coal after mining can be determined based on the data about each mine and the characteristics of coal it produces. The statistic methods were used to average this information for each individual mine and coal seam. The initial data gathered from the mines consisted of over a thousand factors. The research was heavily based on the historic data collected over the last 20–25 years to determine the natural methane content of the industrial coal seams. The information about industrial coal seams volatility was obtained from the technical tests of coal. Most of the data was double-checked with the mines. The transportation and storage time was assumed to be 5 days, after that methane emissions were discounted. Crushing of coal was also discounted.

The study arrives at an estimate of 200.89 million m^3, or 136.4 Gg in total methane emissions from post-mining activities in 2001. Taking into account total coal production for that year, 82.49 million tonnes, an emission factor of **2.44 m^3 /tonne** was derived.[15]

6.2.4 Utilization of Coal-Mining Methane (CMM)

Of all CMM liberated by coal mines, approximately 12.4% is currently extracted through degasification systems, and only 3.5% is utilized. Forty-five mines in Ukraine used degasification systems in 2000, and only 12 mines utilized methane for their needs: 7 mines use methane as a substitute for coal in hot water boilers, one mine uses methane as fuel for cars and trucks, several use methane for power generation at diesel electric generators.

6.2.5 Emission factor estimation

In analyzing the results of the study, it appears that the general trend of the methane emissions is in balance with the general trend of the coal production. Compared to previous estimates of Ukrainian methane emissions from coal mines (First National Communication), the inventory indicates slightly lower values (5% less 1990 and 8% for 1998). This difference is because IPCC Tier 1 methodology was applied for the purposes of the First National Communication. The later estimates, however, appear to be more precise as they are derived from a combination of actual and calculated data.

[15] 1996 Revised IPCC Guidelines recommend methane emission factor of 0.2 to 4.0 m^3 per tonne.

The country specific emission factor that can be derived from the inventory, 16.55 m^3/tonne on average between 1990 and 2001 is close to the lower edge of the range recommended as IPCC default value for Former Soviet Union region (17.8 – 22.2 m^3/tonne).

Figure 6.1. Methane Emissions from Ukrainian mines 1990-2001

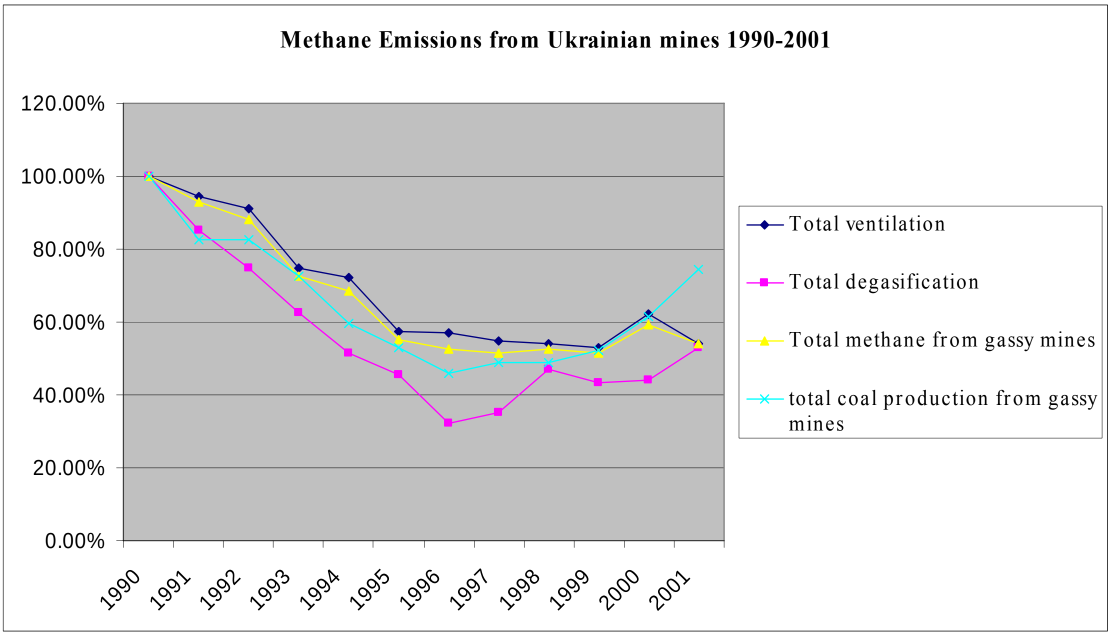

Table 6.1. Methane Emissions and Emission Factors from Ukrainian Mines, 1990-1991

Gassy Mines (Measured Emissions)									Non-Gassy Mines		Total underground mines coal production and methane emissions		
Year	Total ventilation m^3	Total degasification, m^3	Total methane from gassy mines	Total methane less utilization	Share of methane utilized	Total coal production from gassy mines	Emission factor total	Emission factor less utilization	Coal produced mln raw tonnes	CH_4 emitted m^3	Total coal produced mln raw tonnes	Total methane emitted m^3	National emission factor
1990	1,946.46	403.73	2350.19	2251.73	0.04	106.08	22.15488	21.22672	49.44	167.85	155.52	2,419.58	15.557999
1991	1,839.30	344.52	2183.82	2089.98	0.04	87.76	24.884	23.81472	40.69	138.14	128.45	2,228.12	17.3462047
1992	1,771.09	302.75	2073.84	2013.84	0.03	87.74	23.6362	22.95236	40.08	136.06	127.81	2,149.90	16.8210625
1993	1,455.83	252.21	1708.04	1660.85	0.03	76.88	22.21696	21.60315	34.73	117.89	111.6	1,778.74	15.9385305
1994	1,402.95	207.29	1610.24	1545.7	0.04	63.45	25.37809	24.36091	28.33	96.19	91.78	1,641.89	17.8894095
1995	1,114.91	183.68	1298.59	1238.04	0.05	56.23	23.09426	22.01743	25.08	85.15	81.31	1,323.19	16.2733981
1996	1,110.01	129.60	1239.61	1206.92	0.03	48.58	25.51688	24.84397	21.5	72.99	70.07	1,279.91	18.2661624
1997	1,069.66	142.45	1212.11	1173.52	0.03	51.7	23.44507	22.69865	22.77	77.3	74.47	1,250.82	16.7962938
1998	1,049.02	190.27	1239.29	1182.66	0.05	51.92	23.86922	22.77851	22.85	77.57	74.77	1,260.23	16.8547546
1999	1034.03	174.31	1208.34	1154.66	0.04	55.56	21.74838	20.78222	24.32	82.55	79.87	1,237.21	15.4902967
2000	1,211.60	177.79	1389.39	1339.8	0.04	65.3	21.27703	20.51761	13.91	47.29	79.21	1,387.09	17.5115516
2001	997.28	182.15	1179.42	1088.09	0.08	65.48	18.01191	16.61714	17	57.72	82.49	1,145.81	13.8902897
						average	22.93607	22.01778					16.5529961
						sd	2.080238	2.181828					1.21191648
						confidence interval	0.037656	0.039495					0.02193791

6.3 KAZAKHSTAN [34]

Kazakhstan is the third largest producer of coal in Former Soviet Union region after Russia and Ukraine and ranks the eighth among the world producers. On per capita basis, Kazakhstan takes first place in the Former Soviet Union with coal production of 4.5 t/per capita, which is 3 times higher than in Russia and Ukraine. There are about 100 coal deposits in Kazakhstan with geological reserves estimated at 176.7 billion tonnes. However only 40 of the deposits have been explored and the estimated production reserves amount to 34.1 billion tonnes.

Kazakhstan produces either sub-bituminous coals or lignite from both surface and underground mines. Ekibastuz, Kuuchekinsky and Borlinsky coal deposits are sub-bituminous of low quality (high ash, sulfur content, and low heat content). These are mainly used at power plants to produce electricity and heat. The Shubarkol, Karaganda and Maykyuben coal deposits are of high quality and used mainly as a fuel in industrial and residential sectors.

The largest coal basins, Karaganda and Ekibastuz, are responsible for about 95 % of the total coal production in Kazakhstan. The main coal deposits are located throughout the central part of the country, which is geographically convenient for coal transportation throughout the country. Nevertheless, transportation difficulties occur due to the low scale of development and carrying capacity of the railway system.

Kazakhstan mines are aggregated into several coal producing associations (enterprises), of which three are the largest.

6.3.1 Underground Coal Mining

Underground mining is present only in the Karaganda basin, which is the largest coal mining region in Kazakhstan. These coals have relatively high ash content and are difficult to wash. In 1990, 26 underground mines operated in Kazakhstan. By 1995, with many inefficient and unprofitable mines closed. Of the 12 mines remaining in 1995, only eight were still operating in 2001 and four have nearly stopped production.

Mines in the Karaganda basin are considered to be very "gassy" with a high methane content. The coal is mined at the depth of 650-700 m and production of 1 tonne of coal is accompanied by release of about 33 m^3 methane to the mine. Thus special attention is paid to lower the methane content in the mines and provide for its utilization. Surface wells are widely used in the basin to provide degasification of the strata. The level of methane utilization is very low although some portion of methane is recovered and used as fuel for heating. About 10-12 million m^3 is recovered and combusted in 3-4 boiler installations. In addition, a portion of methane emissions have been flared since 1999.

For safety reasons methane emissions from mine ventilation and degasification systems are measured and recorded, therefore a detailed Tier 3 methodology, as recommended by Revised IPCC Guidelines was applied. However, because of the restructuring of the mining inventory, only the data from operating underground mines were analyzed. "Ispat-Karmet" JSC that operates the eight remaining mines was contacted for information. Total emissions from underground mines were estimated as the sum of the methane emissions measured from each mine's ventilation and degasification systems. The amount of methane utilized for internal purposes was then subtracted from the total to estimate the amount flared.

6.3.2 Surface Mining

Surface coal mining in Kazakhstan occurs throughout the country and accounts for an increasing share of total coal production -- from 73% in 1990 to 89% in 2000. There are numerous coal basins in Kazakhstan suitable for surface mining, but only a few are currently exploited.

Ekibastuz basin is the center of the surface coal mining industry in Kazakhstan and has been exploited since 1955. The main deposit contains about 7 billion tons of coal with over 75 billion m^3 of methane embedded. Coal is produced at 3 open pit mines. Ekibastuz coal is characterized by high content of ash, sulfur, and mineral gangu. The Ekibastuz basin open pit mines are the largest in Kazakhstan, responsible for 75-85% of the total surface coal production in the Republic.

There are a number of small open pit coal mines located in different regions of Kazakhstan that account for the remaining 15-25% of surface coal production, these include: one open pit mine at *Shubarcolskoe* deposit producing high-quality coals, *Borlinskoe* deposit producing low-quality sub-bituminous coal, two open pits producing low quality coals at *Kuuchekinskoe* deposit north of Karaganda city, one open pit mine at *Maykyubensky* basin, and *Lowili deposit* with a large seam of lignite with high ash and low sulfur content.

Surface mines in Kazakhstan are considered to be very gassy for open mining pattern. Special efforts are therefore made to remove methane by blowing air through the tunnels, resulting in roughly 70% of methane escaping to the atmosphere in the form of ventilation air. Methane emissions from open pit mines were estimated separately for big mines and the numerous small mines. The Tier II methodology was applied to estimate the CH4 emissions from the three largest open pit mines in the Ekibastuz basin. Experts from two coal-producing enterprises operating the mines were contacted to obtain additional data.

Table 6.2. Data used for methane emissions estimation from surface coal mining[16]

	Coal Production, million t			In-situ gas content
Years	Severny mine	Bogatyr mine	Vostochny mine	for Bogatyr, m^3 $CH4^{/t}$
1990	15.0	37.0	20.9	9
1991	14.5	34.8	22.8	9
1992	13.9	32.7	21.7	9
1993	13.4	30.5	21.1	9
1994	12.9	28.3	19.3	9
1995	12.4	26.1	19.9	9
1996	11.8	24.0	17.0	9
1997	11.3	21.8	14.8	9.1
1998	15.1	21.4	10.9	8.6
1999	10.7	17.1	11.1	9.2
2000	12.7	23.1	16.0	9.2

Data on the in-situ gas content obtained for the "Bogatyr" open pit mine for 1997-2000 were applied as the in-situ gas content for the 1990-1996 period. The in-situ gas content of the “Vostochny” was assumed to be equal to that of "Bogatyr" as these two mines have a similar methane bearing capacity (about 8-12 m^3 per ton) as they are located in the same deposit close to

[16] 1990-2000 coal production data were available only for "Vostochny" mine. For "Severny" and "Bogatyr" mines 1997-2000 production data were interpolated to 1990-1996 period.

each other and have similar coal characteristics and mining conditions. According to expert judgment at the "Severny" mine, coal is produced in the methane-free strata (above 200 m) thus CH_4 emissions from this mine are negligible.

The number of open pit mines is rather high and not all submitted the requested data. Methane emissions from the rest of the open pit coal mines were estimated using the Tier I methodology. Coal production from these mines was defined as the difference between total coal production in Kazakhstan minus the coal production by the "Ispat-Karmet" underground mines and by the "Bogatyr", "Vostochny" and "Severny" open pit mines. The emission factor was taken from the Revised IPCC Guidelines (Tier I).

Emissions from the surrounding strata were assumed to be negligible, as the surrounding strata consists mostly of sand and rocks.

6.3.3 Post-Mining Emissions

A national emission factor equal to 1 m^3 of CH_4 per ton of coal produced was used to estimate post-mining emissions from underground mines, based on the expert assessment of "Ispat-Karmet" JSC. This value reflects the normative emissions in accordance with "Guidelines for designing of ventilation systems at coal mines" and "Handbook for designing of coal-mining buildings and processing plants with highly explosive and fire-risk conditions". Post-mining emissions from surface mining were assumed to be negligible. No estimates were made of the emissions from abandoned mines because of data availability issues.

Based on actual measurements from underground mines and activity data combined for surface mines, overall methane emissions from coal-mining activities in Kazakhstan were estimated. The inventory compilers estimated overall uncertainty as ±20%.

Figure 6.2. Trends in Underground Coal Production and CMM Emissions in Kazakhstan, 1990-2000

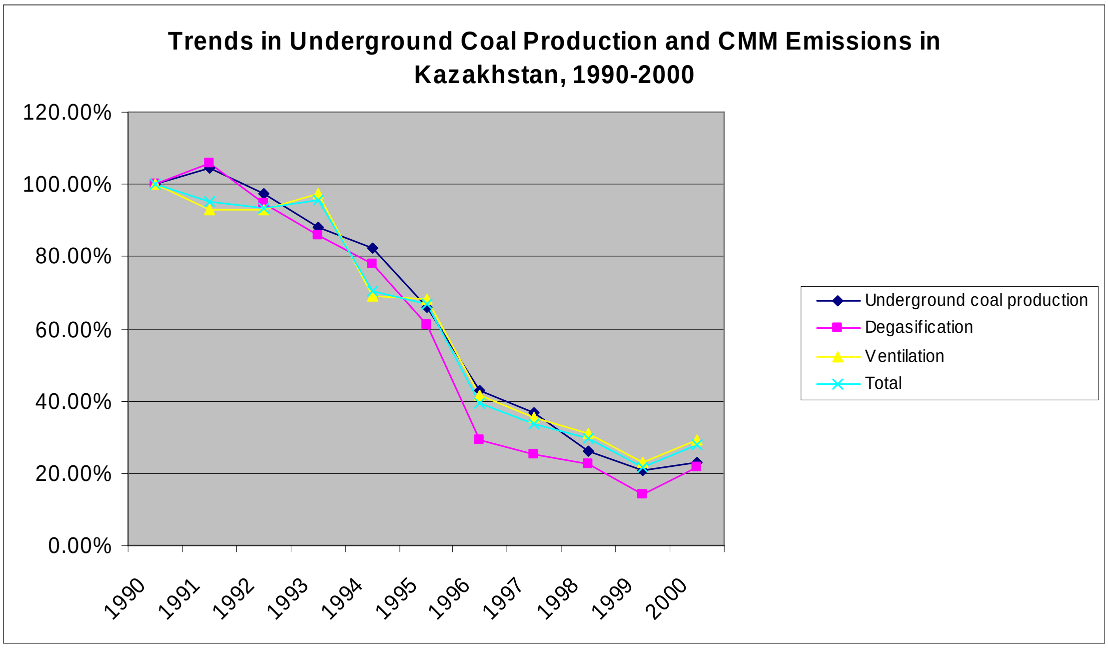

Table 6.3. Data used for methane emissions estimation from surface coal mining[17]

Years	Total Coal Production, mln t	Underground Coal Production, mln t	Measured methane emissions, mln m3			Emission factor for underground coal	Methane utilized and/or flared, mln m3	EF for underground coal less methane utilization	Calculated methane emissions, mln m3			Total Emitted Methane, m^3	National emission factor, m^3
			Degasification	Ventilation	Total				Surface mines, Tier II	Surface mines, Tier I,	Post-mining activities		
1990	131.44	35.31	189.84	983.66	1173.50	33.23	9.09	32.98	521.28	46.43	35.31	1767.43	13.45
1991	130.38	36.91	200.83	914.75	1115.58	30.22	11.16	29.92	519.00	42.67	36.91	1703.00	13.06
1992	126.54	34.40	179.97	915.52	1095.49	31.85	11.30	31.52	488.90	47.75	34.40	1655.24	13.08
1993	111.88	31.10	162.96	957.82	1120.78	36.04	13.25	35.61	463.94	31.63	31.10	1634.21	14.61
1994	104.63	29.14	148.31	678.12	826.43	28.36	5.74	28.16	428.19	30.04	29.13	1308.06	12.50
1995	83.36	23.30	115.80	671.37	787.17	33.78	6.10	33.52	414.24	3.34	23.30	1221.94	14.66
1996	76.83	15.10	55.40	408.00	463.40	30.69	3.60	30.45	369.16	17.76	15.10	861.84	11.22
1997	72.59	12.90	48.20	347.45	395.65	30.67	4.03	30.36	331.43	23.60	12.90	759.57	10.46
1998	69.71	9.20	42.60	303.45	346.05	37.61	10.70	36.45	282.24	26.21	9.19	653.00	9.37
1999	58.20	7.30	27.20	227.32	254.52	34.87	11.60	33.28	257.07	24.03	7.30	531.31	9.13
2000	74.87	8.20	41.00	286.23	327.23	39.91	12.50	38.38	356.43	29.76	8.19	709.13	9.47
					average	33.38		32.78					11.91
					SD	3.33		2.96					1.98

[17] 1990-2000 coal production data were available only for "Vostochny" mine. For "Severny" and "Bogatyr" mines 1997-2000 production data were interpolated to 1990-1996 period.

GHG emissions are generated by the calcination process, which is the chemical transformation of input materials into cement, and the combustion of fuels to generate the heat necessary for calcinations to occur. In 2002, Ukrainian Agency for Rational Energy Use and Ecology conducted an inventory of GHG emissions from cement manufacturing sector, which among other included CO_2 emissions from chemical processes during clinker production. [43]

As background, CO2 is produced during clinker production, an intermediate product from which cement is made. In the temperature range of 820-907^{0}C CaCO3 from lime decomposes into CaO and CO_2, the latter being a byproduct of the reaction. Silica, aluminum, and iron oxides react with CaO to mineralize the clinker and form calcium silicate. The clinker, the end product of the baking process, is a system of artificial minerals: $3CaO \cdot SiO_2$, $2CaO \cdot SiO_2$, $3CaO \cdot Al_2O_3$ and $2CaO \cdot Fe_2O_3$, which contains intermediate products from the unfinished reactions, as well as various admixtures of inactive ballast compounds.

Since clinker consists of different artificial minerals and based on the fraction of each mineral in clinker, the CO2 inventory factors for the calcination process might be specified by using the atomic mass of each chemical components of the minerals. In general, the CO2 estimation factor for calcination is specified based on the information related to clinker production, using the following formula

$$K_{CO_2}^{cl} = 0.785 \sum \delta_i \xi_i \, , \qquad (13)$$

where,

$K_{co_2}^{cl}$	CO_2 emission factors for calcination process, t CO2/t clinker
0.785	ratio of molecular weight of CO2 and CaO, relative units
i	index of artificial mineral, that contained in clinker
δ_i	content of CaO in i-mineral, relative units
ξ_i	content of each artificial mineral in clinker, relative units.

The CaO content in each artificial mineral contained in the clinker is estimated based on the molecular weight of each element contained in artificial mineral and the molecular weight of the whole artificial mineral.

$$\delta_i = \frac{N_i \mu_{CaO}}{\mu_i} \, , \qquad (14)$$

where,

δ_i	content of CaO in i-mineral, relative units
N_i	number of CaO molecules in each artificial mineral, units
μ_{CaO}	molecular weight of CaO, kg/mole
μ_i	molecular weight of each artificial mineral, contained in a clinker, kg/mole

To establish national CO_2 emission factors for each type of cement produced in Ukraine, Arena-ECO used reference data on cement quality from state standards, using formula (41). The factors are expressed in ton of CO_2 per one ton of clinker are presented in Table 7.1 below.

Table 7.1. CO_2 emission factor by cement types produced in Ukraine

Cement Sub-types	*Clinker content in cement, %*	*Artificial mineral in clinker*	*Mineralogical composition of clinker (% of weight)*	*CaO content in clinker, %*	*CO_2 emission factor, tCO_2/t clinker*	*Sources*
Cement for common construction purposes						
Portland cement	95-100	$3CaO\ SiO_2$ $2CaO\ SiO_2$ $3CaO\ Al_2O_3$ $4CaO\ Al_2O_3\ Fe_2O_3$	40-65 15-40 5-15 10-20	46.97- 92.51	0.369 - 0.726	[45,48]
Portland cement with slag	65-94	$3CaO\ SiO_2$+ +$3CaO\ Al_2O_3$ $2CaO\ SiO_2$+ +$4CaO\ Al_2O_3Fe_2O_3$	0-65 33	43.87- 16.87	0.344- 0.132	[45,48]
Portland cement	80-94	$3CaO\ SiO_2$ $2CaO\ SiO_2$ $3CaO\ Al_2O_3$ $4CaO\ Al_2O_3\ Fe_2O_3$	40-65 15-40 5-15 10-20	46.97-	0.369-	[45,44]
Portland cement with ash ejection	80-94	$3CaO\ SiO_2$ $2CaO\ SiO_2$ $3CaO\ Al_2O_3$ $4CaO\ Al_2O_3\ Fe_2O_3$	40-65 15-40 5-15 10-20	46.97- 92.51	0.369- 0.726	[45,44]
Portland cement limestone	80-94	$3CaO\ SiO_2$ $2CaO\ SiO_2$ $3CaO\ Al_2O_3$ $4CaO\ Al_2O_3\ Fe_2O_3$	40-65 15-40 5-15 10-20	46.97- 92.51	0.369- 0.726	[45,44]
Cement for asbestos cement products	80-94	$3CaO\ SiO_2$ $2CaO\ SiO_2$ $3CaO\ Al_2O_3$ $4CaO\ Al_2O_3\ Fe_2O_3$	40-65 15-40 5-15 10-20	46.97- 9.51	0.369- 0.726	[44,48]
Composite cement	65-94	$3CaO\ SiO_2$ $2CaO\ SiO_2$ $3CaO\ Al_2O_3$ $4CaO\ Al_2O_3\ Fe_2O_3$	40-65 15-40 5-15 10-20	46.97- 92.51	0.369- 0.726	[45,44]
Fast-hardening cement	90	3CaO SiO2+ +$3CaO\ Al_2O_3$ $2CaO\ SiO_2$+ +$4CaO\ Al_2O_3Fe_2O_3$	0-65 35	60.74	0.477	[48]
Road cement	95-100	$3CaO\ SiO_2$ $2CaO\ SiO_2$ $3CaO\ Al_2O_3$ $4CaO\ Al_2O_3\ Fe_2O_3$	40-65 15-40 5-15 10-20	46.97- 92.51	0.369- 0.726	[45,44]
Slag Portland cement	20-64	$3CaO\ SiO_2$ $2CaO\ SiO_2$ $3CaO\ Al_2O_3$ $4CaO\ Al_2O_3\ Fe_2O_3$	40-65 15-40 5-15 10-20	46.97- 92.51	0.369- 0.726	[45,44,48]
Pozzolan cement	45-79	$3CaO\ SiO_2$ $3CaO\ Al_2O_3$ $3CaO\ Al_2O_3$+ +$4CaO\ Al_2O_3Fe_2O_3$ Al2O3 MgO	Not standard 8 Not standard 5 5	45.74	0.359	[46,48]
Composite cement	20-64	$3CaO\ SiO_2$ $2CaO\ SiO_2$ $3CaO\ Al_2O_3$	40-65 15-40 5-15	46.97- 92.51	0.369- 0.726	[44,45]

		$4CaO\ Al_2O_3\ Fe_2O_3$	10-20			
Cement types for cementation without forming	20-64	$3CaO\ SiO_2$ $2CaO\ SiO_2$ $3CaO\ Al_2O_3$ $4CaO\ Al_2O_3\ Fe_2O_3$	40-65 15-40 5-15 10-20	46.97-92.51	0.369-0.726	[44,45]
Sulfate-resistant cements						
Sulfate-resistant Portland cement	100	$3CaO\ SiO_2$ $3CaO\ Al_2O_3$ $3CaO\ Al_2O_3+$ $+4CaO\ Al_2O_3Fe_2O_3$ Al_2O_3 MgO	0-50 0-5 0-22	51.37	0.403	[46,48]
Sulfate-resistant blended Portland cement	80-90	$3CaO\ SiO_2$ $3CaO\ Al_2O_3$ $3CaO\ Al_2O_3+$ $+4CaO\ Al_2O_3Fe_2O_3$ Al2O3 MgO	Not standard 5 22 5 5	60.96	0.478	[46,48]
Sulfate-resistant Slag Portland cement	20-50	$3CaO\ SiO_2$ $3CaO\ Al_2O_3$ $3CaO\ Al_2O_3+$ $+4CaO\ Al_2O_3Fe_2O_3$ Al2O3 MgO	Not standard 8 Not standard 5 5	56.48	0.443	[46,48]
Pozzolan Portland cement	20-40	$3CaO\ SiO_2$ $3CaO\ Al_2O_3$ $3CaO\ Al_2O_3+$ $+4CaO\ Al_2O_3Fe_2O_3$ Al_2O_3 MgO	Not standard 8 Not standard 5 5	56.48	0.443	[46]
Oil-well Portland cement						
Oil-well Portland cement without additives	100	$3CaO\ SiO_2$ $3CaO\ Al_2O_3$ $3CaO\ Al_2O_3+$ $+4CaO\ Al_2O_3Fe_2O_3$	Not standard 3 22	68.32	0.536	[47, 48]
Oil-well Portland cement with normal requirements at water cement rati	100	$3CaO\ SiO_2$ $3CaO\ Al_2O_3$ $3CaO\ Al_2O_3+4CaO$ $Al_2O_3\ Fe_2O_3$	48-65 3-8 24	49.69-65.33	0.390-0.513	[47]
Oil-well blended	80-94	$3CaO\ SiO_2$ $3CaO\ Al_2O_3$ $3CaO\ Al_2O_3+$ $4CaO\ Al_2O_3\ Fe_2O_3$	Not standard 5 22	68.32	0.536	[47, 48]
Oil-well Portland cement with special additives that control cement dough density	30-89	$3CaO\ SiO_2$ $3CaO\ Al_2O_3$ $3CaO\ Al_2O_3+$ $4CaO\ Al_2O_3\ Fe_2O_3$	Not standard 5 22	68.32	0.536	[47, 48]
Alumina cement						
Alumina cement	100	$CaO\ Al_2O_3$, $12CaO\ 7\ Al_2O_3$ $CaO\ 2\ Al_2O_3$ $2CaO\ Al_2O_3\ SiO_2$, FeO		40	0.314	[48,49] [50]
Gypsum and alumina expanding cement	70	$CaO\ Al_2O_3$, $12CaO\ 7\ Al_2O_3$ $CaO\ 2\ Al_2O_3$ $2CaO\ Al_2O_3\ SiO_2$ FeO		40	0.314	[48,49] [50]

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