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

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Annexes

SECTION A. General description of the project

A.1. Title of the project:

Reconstruction of Kirishskaya TPP with installation of 750 MW Combined-Cycle Unit
PDD Version 1.0 dated July 29, 2008

A.2. Description of the project:

Currently, the Kirishskaya TPP with the installed electrical capacity of 2,100 MW, including 1,800 MW of condensing capacity and 300 MW of combined heat and power, and 1234 Gcal/h of the thermal capacity is the largest power plant in the North-West region of Russia. Technologically, the Kirishskaya TPP features to simultaneously operating plants – CHP (6x50 MW, 1234 Gcal/h) and condensing plant (6x300 MW). The plant has been switched to fire natural gas since 2004.

The condensing plant works under dispatching regime with highly regulated capacity. During working day nights 300 MW blocks operate at 40% of installed capacity, while during weekends and holidays 3-4 blocks are left as reserve and remaining blocks are working at minimal output.

Kirishskaya TPP (CHP plant) supplies heat in form of steam and hot water via system of pipelines. Biggest consumer is company KINEF (75%) and town Kirishi (20%).
Produced electricity is transmitted via 330 and also 110, 35, 6 kV lines.

The essence of the project is the addition of two gas-turbine units with electrical capacity of 287 MW each with subsequent utilization of waste-gas heat in new recovery boilers within the reconstruction of the energy block No.6 at the Kirishskaya TPP site.
The energy block No.6 comprises one steam boiler aggregate feeding one steam turbine with nominal electricity output 300 MW. No heat is produced. Natural gas is used as a basic fuel.
After the construction of new gas-turbine units, waste-gases leaving the gas-turbines enter steam (recovery) boilers thus utilizing contained heat. The two recovery boilers will supply steam of three levels of pressure to one existing three-cylinder steam turbine with power output over 250 MW. Original boiler aggregate will be removed.
The whole combined cycle gas turbines unit can operate in primary regime with both gas turbines employed or with only one gas turbine unit in operation.
Project (2 gas-turbines + steam turbine) will supply 4212 thous. MWh.

The goals of the projects are as follows:

- increasing of the efficiency of electricity production: enhancement of efficiency, reduction of specific fuel consumption, reduction of pollutants emissions and GHG emissions;
- securing of system reliability of the OES North-West as a result of installation of up-to-date equipment;
- satisfying the rising demand for electricity and covering of prospective deficit of capacities in the OES North-West;
- improvement of the technical and economical performance of the Kirishskaya TPP.

As electricity will be produced in gas-turbines at relatively lower carbon intensity (taking into account highly efficient equipment and waste-gas heat utilization), the project brings CO_2 emission reduction against baseline situation.

Tab A.2. Financial plan by the expense items, mln. Euro

Expense items	**2007**	**2008**	**2009**	**Total**
Equipment	72.60	119.42	-	192.01
Construction and erection works	-	-	29.75	29.75
Design work, unforeseen costs, other expenses	19.07	19.32	-	38.39
Total without VAT	91.66	138.74	29.75	260.16
VAT (will be financed on own funds)	16.50	24.97	5.36	46.83
Total (including VAT):	**108.16**	**163.72**	**35.11**	**306.99**

Exchange rate NBR RUB/EUR 36.5125 as of 4 March 2008 applied

Expenses were indexed (1.113 for 2007, 1.092 for 2008 and 1.07 for 2009) for calculation of an investment efficiency (section B.).

A.3. Project participants:

Party involved	Legal entity project participant (as applicable)	Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)
Russian Federation (Host party)	• JSC "Sixth Wholesale Power Market Generating Company" • Energy Carbon Fund	No

JSC "Sixth Wholesale Power Market Generating Company" (WGC-6)
The Sixth Wholesale Power Market Generating Company JSC (JSC WGC-6; Russian: OGK-6) was founded on the basis of the order of RAO United Energy Systems (UES) of Russia dated March 16, 2005 as a part of the reformation of the power industry. Wholesale generating companies were created on the basis of major power stations belonging to RAO UES of Russia. At present JSC "WGC-6" is the sole executive body of six power stations: Novocherkassk TPP OJSC, Kirishi TPP OJSC, Ryazan TPP OJSC, Krasnoyarsk TPP-2 OJSC, Cherepovetsk TPP OJSC and TPP-24 OJSC. (Instead of "TPP", sometimes "SDPP" is used.) The total installed capacity of the stations amounts to 9,052 MW. The powers of the sole executive body were delegated to JSC "WGC-6" on the basis of contracts concluded with all the stations. The assets to be included in JSC "WGC-6" were selected in accordance with the principles which are common for all wholesale generating companies and which are fixed in legislation of the Russian Federation. First of all, all WGCs were created in accordance with the extra-territorial characteristic – they combine stations situated in different parts of the country. JSC "WGC-6" is the second company in terms of the installed capacity among the created thermal wholesale generating companies.

ECF Project Ltd. was established in July 2007 by Energy Carbon Fund under Russian JSC “Unified Energy System of Russia”, one of the largest energy utility companies in the world. ECF Project is designed as revolving investment mechanism for implementation of energy efficiency improvement projects to promote sustainable development by taking the opportunities of market based mechanisms laid down in the Kyoto protocol to the United National Framework Convention on Climate Change.
The main activities of the ECF Project are the follows:

- ECF Project is conducting of the inventory of the greenhouse gas emissions and development of the GHG emission monitoring system at former RAO "UES of Russia" enterprises (the inventories were completed for 107 entities);
- ECF Project carried out the analysis of all projects including in the Investment Program of RAO "UES of Russia" till 2010;
- ECF Project provides complete cycle for JI project from PIN to signing ERPA.

A.4. Technical description of the project:

A.4.1. Location of the project:

Kirishskaya TPP is located on the right side of Volkhov river in the industrial area 3 km from the town Kirishi, Leningrad Oblast. Refinery PO Kirishi-Nefteorgsintez (KINEF) is situated next to Kirishskaya TPP.

A.4.1.1. Host Party(ies):

Russian Federation

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

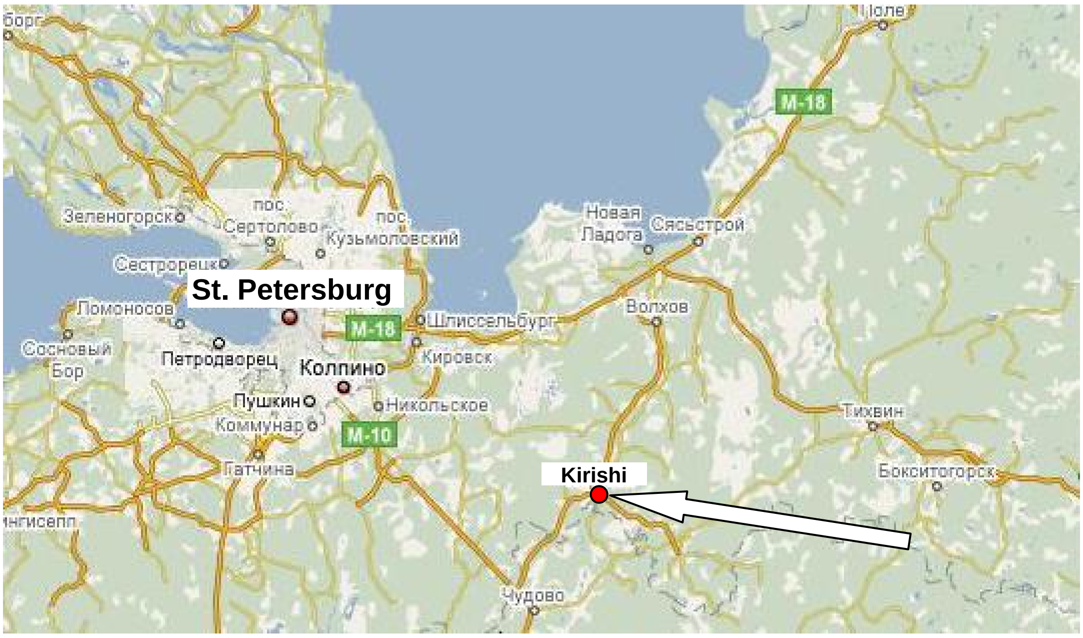
Leningrad Oblast

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

Town Kirishi

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

Kirishskaya TPP is located on the right side of Volkhov river in the industrial area 3 km from the town Kirishi, Leningrad Oblast. Distance from St. Petersburg to town Kirishi is 150 km by motorway direction south-east. Refinery PO Kirishi-Nefteorgsintez (KINEF) is situated next to Kirishskaya TPP.



Leningrad Oblast is a federal subject of Russia. The administrative center of the oblast is Saint Petersburg, although it constitutes a separate federal subject (a federal city) and is administratively separate from the oblast. Leningrad Oblast is bordered by Finland in the northwest, Estonia in the west, as well as five federal subjects of Russia: Republic of Karelia in the northeast, Vologda Oblast in the east, Novgorod Oblast in the south, Pskov Oblast in the southwest, and the federal city of Saint Petersburg it surrounds. The oblast has an area of 84,500 km² and a population 1,669,205 (as of the 2002).
Kirishi (Russian: Кириши; population: 55,400) is a town in Leningrad Oblast, Russia, situated on the right bank of the Volkhov River, 115 km south-east of St. Petersburg.

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

Total installed electrical capacity of the Kirishskaya TPP is 2100 MW, including 1800 MW of condensing capacity and 300 MW of combined heat and power, and 1234 Gcal/h of heat. Technologically, the Kirishskaya TPP features to simultaneously operating plants – CHP (6x50 MW, 1234 Gcal/h) and Condensing plant (6x300 MW). Natural gas is used as a basic fuel, heavy oil as a reserve fuel. In 2007, power output of Kirishskaya TPP was 6 645 thous. MWh, heat output 11 154 TJ.
The energy block No.6 comprises one steam boiler aggregate TGMP-324 feeding one steam turbine K-300-240-1 with nominal electricity output 300 MW. No heat is produced. Natural gas is used as a basic fuel.

It is planned under the project that two gas-turbine units Siemens SGT5-4000F (formerly known as V94.3A) with electrical capacity of 287 MW each (specification by Siemens) will be constructed in new building next to site of energy block No.6 in Condensing plant. Together with each gas-turbine the three section (low pressure, intermediate pressure and high pressure section) heat recovery steam generator (recovery boiler) will be constructed for subsequent utilization of waste-gas heat from gas-turbine.

The two recovery boilers will supply steam of three levels of pressure to one existing three-cylinder steam turbine K-300-240-1 with power output over 250 MW. Original boiler aggregate will finish operation.
The whole CCU can operate in primary regime with both GTU employed or with only one GTU in operation.

Some other necessary works:

- extension of 330 kV line
- construction of two transformers open-air station
- construction of gas pipeline 5.25 km (pressure 5.4 MPa)

The project will exploite existing infrastructure of Kirishskaya TPP as much as possible.

Tab A.4.2.1. Installed equipment

Installed equipment BEFORE beginning of implementation of the project:

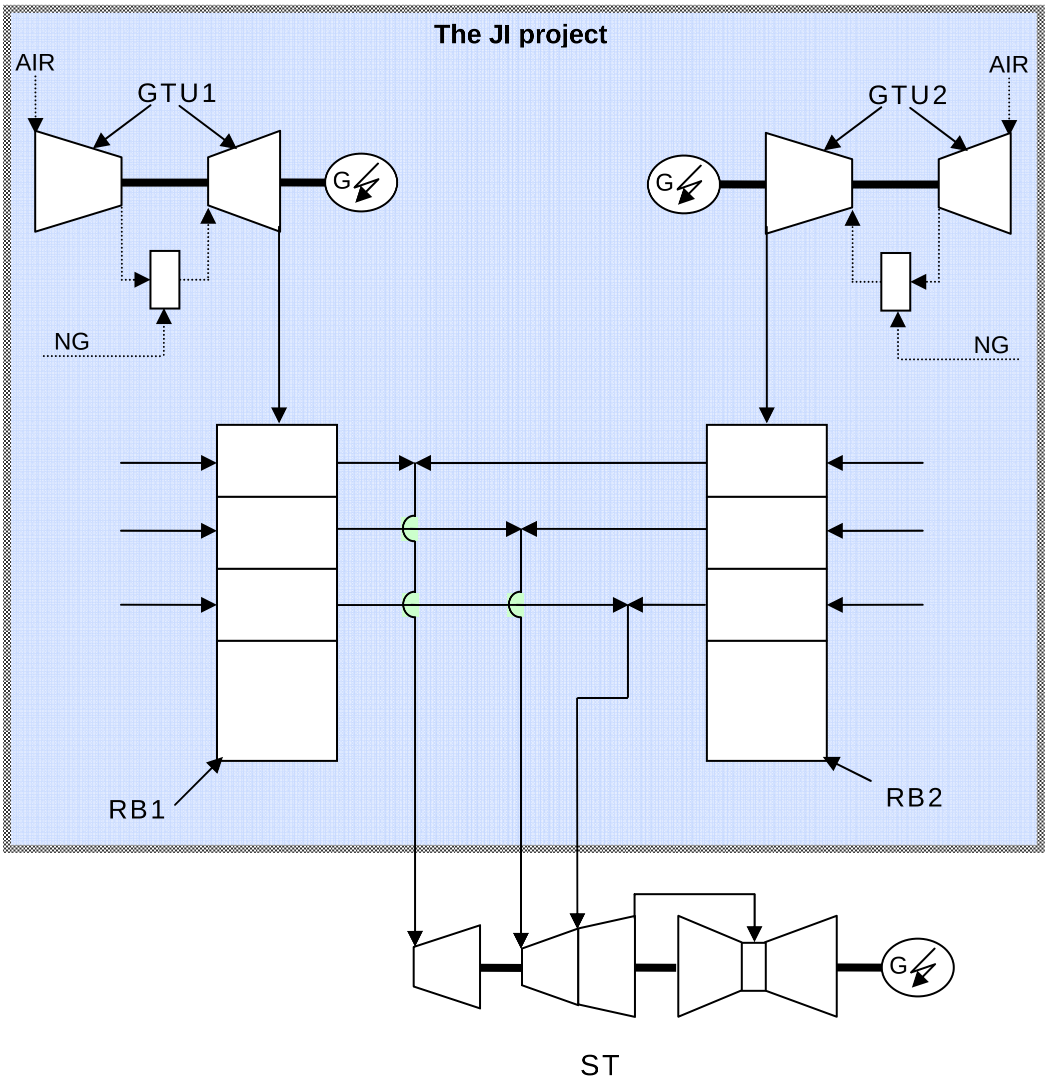
Type	Pieces	Installed Capacity		Manufacturer
Condensing plant				
TURBINES		electricity (MW)	heat (Gcal/h)	
K-300-240	6	300	0	OJSC LMZ, Russia
BOILERS		parameters of steam		
TGMP-114	3	(255 kg/cm^2; 545°C)		Taganrog Boiler Factory
TGMP-324A*)	3	(255 kg/cm^2; 535°C)		Taganrog Boiler Factory
CHP plant				
TURBINES		electricity (MW)	heat (Gcal/h)	
PT-50-130/7	2	50	110	TMZ
PT-60-130/13	2	60	139	TMZ
R-40-130	2	40	164	OJSC LMZ, Russia
BOILERS		parameters of steam		
TGM-84B**)	6	420 t/h (steam 140 kg/cm^2, 550°C)		Taganrog Boiler Factory
KVGM-100***)	2			

Installed equipment AFTER full implementation of the project:

Type	Pieces	Installed Capacity		Manufacturer
Condensing plant				
TURBINES		electricity (MW)	heat (Gcal/h)	
K-300-240	6	300	0	OJSC LMZ, Russia
SGT5-4000F	2	280	0	Siemens AG, Germany
BOILERS		parameters of steam		
TGMP-114	3	(255 kg/cm^2; 545°C)		Taganrog Boiler Factory
TGMP-324A*)	2	(255 kg/cm^2; 535°C)		Taganrog Boiler Factory
recovery boiler	2			
CHP plant				
No change				

*) KP 04 is type TGMP-324
**) KP 1T and KP 2T are type TGM-84; KP 3T is type TGM-84A
***) Hot water boilers
OJSC LMZ = Open joint-stock company Leningradsky Metallichesky Zavod, Russia

Figure A.4.2.1. Scheme of Kirishskaya TPP – the project of reconstruction of block No.6



GTU – gas turbine SGT5-4000F
RB – recovery boiler
ST – steam turbine K-300-240-1
G – electrical generator
NG – natural gas

Table A.4.2.2. Main characteristics of Kirishskaya TPP (Condensing plant) and the project

Parameter	Project	Condensing plant (2011)	
		Without project	With project
Gas-turbine unit	SGT5-4000F		
Steam/Recovery boiler	2 new		
Steam turbine	K-300-240-1		
Installed electrical capacity, MW	840*)	1800	2340
Installed heat capacity, Gcal/h	0	0	0
Electricity generation, thous. MWh	4500	4 673	8 394
Power output, thous. MWh	4212	4 374	7 857
Heat generation, TJ	0	0	0
Fuel consumption			
natural gas, thous. Nm^3	813 366	1 081 378	1 714 514
heavy fuel oil, t	0	208 760	173 966
Electrical efficiency of the plant, %	55.45	35.3	43.8

*) GTUs: 2x288, ST: 264

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

The anthropogenic emissions of greenhouse gases by sources are to be reduced by the proposed JI project by increasing energy (electricity) production efficiency. The new gas-turbines will be added to existing steam turbine.

A gas turbine extracts energy from a flow of combustion gas when air is mixed with natural gas and ignited in the combustor. The resulting gases are directed over the turbine's blades, spinning the turbine. After turbine, gases still containing significant volume of heat are used in heat recovery steam generator (recovery boiler).

After full implementation of the project the Condensing plant of the Kirishskaya TPP will deliver more electricity than currently (up to 7857 thous. MWh in total), therefore additional electricity amount will be supplied into public grid, replacing electricity produced by current power plants pool within OES North-West and import from OES Center.

In absence of the project, the Condensing plant of the Kirishskaya TPP would continue producing electricity on steam turbines and remaining quantity of electricity (7857-4374=3483 thous. MWh) would be produced by power plants within OES North-West and OES Center at higher overall CO_2 emission factor comparing to the project gas turbines.

Therefore, if project is not implemented, production of the same quantity of electricity would lead to higher CO_2 emissions.

Table A.4.3.1. Emission factors

Emissions per unit of produced electricity (emission factor) [tCO_2/MWh]		
Current status (steam turbines)	Baseline scenario (grid)	Project scenario (CCGT)
0.6100	0.5199	0.4773

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

	Years
Length of the crediting period	2
Year	Estimate of annual emission reductions in tonnes of CO_2 equivalent
2008	not applicable
2009	not applicable
2010	not applicable
2011	729 124
2012	728 601
TOTAL	**1 457 726**
Annual average	728 863

A.5. Project approval by the Parties involved:

The Parties' Letters of Approval will be received later.

SECTION B. Baseline

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

The methodology selection

According to the JISC document: Guidance on Criteria for Baseline Setting and Monitoring, version 01, paragraph 20 (b), the project participants may establish a baseline that is in accordance with appendix B of the JI guidelines. In doing so, selected elements or combinations of approved CDM baseline and monitoring methodologies or approved CDM methodological tools may be used, as appropriate.
Based on that, the Approved baseline methodology AM0029 "Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas", version 02 has been tested for applicability.

Applicability test:

Condition	Aplicable?	Justification
The project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant	YES	New natural gas fired gas-turbine units will be constructed and connected to the grid
The geographical/physical boundaries of the baseline grid can be clearly identified and information pertaining to the grid and estimating baseline emissions is publicly available	YES	Baseline grid is identified as OES North-West ans OES Center and data for estimating baseline emissions are available
Natural gas is sufficiently available in the region or country, e.g. future natural gas based power capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity	YES	Natural gas is definitely sufficiently available in the region

Therefore, the Approved baseline methodology AM0029 "Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas", version 02 is applicable to the project.

The methodology AM0029 has been applied with following deviations:

1/ For baseline CO_2 emission factor the option 2 (the combined margin 50/50) is selected directly.

In this case, methodology AM0029 requests to use lowest emission factor out of three options:

Option 1: The build margin EF, calculated according to "Tool to calculate emission factor for an electricity system";

Option 2: The combined margin EF, calculated according to "Tool to calculate emission factor for an electricity system", using a 50/50 OM/BM weight; and

Option 3: The EF of the technology (and fuel) identified as the most likely baseline scenario.

Lowest emission factor would be BM emission factor calculated from production data of five power plants put in operation most recently in Russian Federation. All these power plants produce electricity by employing combined cycle with high efficiency. As a consequence, the build margin emission factor is nearly equal to emission factor for gas turbine with high efficiency (implemented within the project). It is certainly not realistic to expect that within period till 2012 electricity will be produced on all fossil fuel power plants of OES North West and OES Center with such high efficiency as corresponds to build margin emission factor. There will be always some coal-fired power plants in both OESs in order to sustain diversified fuel supply and as a reaction to steep increase of natural gas price. (In fact, within OES Center growing share of coal-fired power plants is expected.) In addition, build margin represents only 1.9 % of such a big systems as OES Center and OES North-West (installed capacity in total

60 thous. MW, 107 power plants) and to replace or reconstruct such a big number of power plants within 4 years (until 2012) is impossible.

The approach using combined margin EF applying a 50/50 OM/BM weight reflects reality much better and it is still sufficiently conservative assuming that 50% of power plants of OES North-West and OES Center reach electricity production efficiency corresponding the build margin EF.

2/ When identifying the cohort of power units to be included in the build margin, the set of five power units that have been built most recently was used.
According to "Tool to calculate emission factor for an electricity system", the sample group of power units used to calculate the build margin consists of either:

(a) The set of five power units that have been built most recently, or

(b) The set of power capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently.

Project participants should use the set of power units that comprises the **larger annual generation**. However, if the set comprising the larger annual generation from two choices is used, it leads to inclusion of relatively old power plants (older than 20 years). Reason is that both whole Russia or even OES North West + OES Center are very big systems which did not experienced intense additions within last 20 years. Therefore set of five power units that have been built most recently is considered as better reflecting expected development and represents more conservative approach, too.

3/ AM0029 requires for the assessment of additionality within Step 1: Benchmark investment analysis, accomplishment of **sub-step 2b Option III: Benchmark analysis** of the latest version of the “Tool for demonstration assessment and of additionality”.

Purpose of benchmark analysis is to demonstrate that the proposed CDM (here applied for JI) project activity is unlikely to be financially attractive. However, benchmark analysis of IRR does not bring sound results if applied to JI projects in Russia. Reason is that though usual Russian commercial banks' loan interest rate e.g. 12% might be considered as a benchmark, real level of IRR cannot be calculated as in Russia the prices for electricity are regulated by the State. Future electricity price is difficult to predict, however, IRR is highly sensitive to it thus comparison of IRR of alternatives in question provides much better result because state regulation and price changes would be the same for all alternatives. Hence, option II (investment comparison analysis) is used.

For more information regarding the methodology and its consideration by the JI Supervisory Committee please refer to http://cdm.unfccc.int/methodologies/approved.

The methodology of the carbon intensity calculation – replaceable electricity

Pursuant to the "Tool to calculate emission factor for an electricity system" (Version 01), the **baseline emission factor** (**$EF_{grid,CM,y}$**) is calculated as a **combined margin (CM)**, consisting of the combination of **operating margin (OM)** and **build margin (BM)** factors. Calculations for the combined margin is based on data from an official source, where available and made publicly available. As explained in B.3, relevant electric power system encompasses OES North West and OES Center.

Pursuant to AM0029, for baseline CO_2 emission factor the option 2 (the combined margin 50/50) is selected directly (explanation above). Furthermore, if either option 1 (BM) or option 2 (CM) are selected, they will be estimated *ex post*, as described in “Tool to calculate emission factor for an electricity system”. Therefore, **ex-post** option for data vintages was selected for both OM and BM. The selected ex-post approach will reflect much better changes in electricity production pattern.

Selection an operating margin (OM) method

The simple OM method was used for Calculation of the Operating Margin emission factors, because:

- low-cost/must-run resources constitute less than 50% of total grid generation;
- dispatch data are not available;
- fuel consumption data is available for each power plant.

Regarding first condition (i.e. low-cost/must-run resources constitute less than 50% of total grid generation), real share of low-cost/must-run generation ranges closely around 50%. According to forcasted capacity development in OES North-West (В. Непомнящий, В. Рябов: Энерго-экономические и экологические проблемы вывода из эксплуатации действующих блоков Ленинградской и Кольской АЭС), the share of low-cost/must-run generation will fall from 52% in 2004 to 48,6% in 2010 and 43,2% in 2015. It means that when project starts operation in 2011, low-cost/must-run generation will constitute less than 50% of total generation of OES North-West.
In OES Center low-cost/must-run resources generation is projected to constitute 38% of total generation in 2008.

Calculation of the operating margin emission factors

For the baseline determination shall only account CO_2 emissions from electricity generation in fossil fuel fired power plants that is displaced due to the project activity.
The simple OM emission factor is calculated as the generation-weighted average emissions per unit net electricity generation (tCO_2/MWh) of all generating power plants serving the system, not including low-cost/must-run power plants. Calculation is based on data on fuel consumption and net electricity generation of each power plant (option A):

$$EF_{grid,OMsimple,y} = \frac{\sum_{i,m} FC_{i,m,y} \cdot NCV_{i,y} \cdot EF_{CO2,i,y}}{\sum_{m} EG_{m,y}}$$

Where:

$EF_{grid,OMsimple,y}$	=	Simple operating margin CO_2 emission factor in year y (tCO_2/MWh)
$FC_{i,m,y}$	=	Amount of fossil fuel type i consumed by power plant / unit m in year y (mass or volume unit)
$NCV_{i,y}$	=	Net calorific value (energy content) of fossil fuel type i in year y (GJ / mass or volume unit)
$EF_{CO2,i,y}$	=	CO_2 emission factor of fossil fuel type i in year y (tCO_2/GJ)
$EG_{m,y}$	=	Net electricity generated and delivered to the grid by power plant / unit m in year y (MWh)
m	=	All power plants / units serving the grid in year y except low-cost / must-run power plants / units
i	=	All fossil fuel types combusted in power plant / unit m in year y
y	=	The applicable year during monitoring (ex post option)

The project site and all power plants connected physically to the electricity system that the Kirishskaya TPP is connected to and that can be dispatched without significant transmission constraints is represented by set of power plants grouped in OES North-West. Thus, for the purpose of determining the electricity emission factor, OES North-West represents the relevant electric power system.

Therefore, calculation of operating margin emission factors was based on analysis of structure of set of power plants grouped in OES North-West. For this purpose number of 30 fossil fuel power plants within OES North-West was selected out of regional generating companies from Arkhangelskoe RDU, Karelskoe RDU, Kolskoe RDU, Komi RDU, Leningradskoe RDU, Novgorodskoe RDU, Vologodskaya oblast and Pskovskaya oblast. Low-cost power plants preferably connected to grid (renewable energy sources) were not included in selection.

Total capacity of sources within OES North-West is 12 266.6 MW. Installed capacity of selected fossil fuel power plants is 10 766 MW (51.5%), capacity of nuclear, hydro and biomass power plants is 8 618.3 MW (41.3%). Remaining capacity belongs to industrial power plants with capacity 1 500.9 MW (7.2%).

As OES North-West imports power from OES Center, after project implementation import will drop; thereby certain amount of electricity produced in OES Centre is replaced by Kirishskaya TPP production.

Total capacity of sources within OES Center is 49 312 MW. Installed capacity of selected fossil fuel power plants is 32 499 MW (66%), capacity of nuclear, hydro and biomass power plants is 14 099 MW (28%). Remaining capacity belongs to industrial power plants with capacity 2 715 MW (5.5%). There is surplus installed capacity in OES Center 1 423.1 MW.

After implementation of the project, Kirishskaya TPP will supply to the grid 9 173 thous. MWh of electricity annualy. From this amount, enhanced production of electricity (3 483 thous. MWh) will replace part of electricity generated in OES North-West (2 771 thous. MWh) and part of electricity generated in OES Center (712 thous. MWh) by fossil fuel power plants. These figures also represent replaced electricity split between above-mentioned OESs. Simple operating margin CO_2 emission factor will therefore consist of respective simple operating margin CO_2 emission factors for OES North-West (weight 0.796 or 79.6%) and OES Center (weight 0.204 or 20.4%).

Furthermore, as a part of the project realization, the 300 MWe steam turbine K-300-240 will be removed from energoblock No.6 and with lowered capacity becomes a part of new turbo-aggregate (i.e. 2 gas turbines with recovery boilers and the steam turbine). Thus part of electricity generated by Kirishskaya TPP in absence of the project (729 thous. MWh) will be replaced under project scenario by electricity generated by new turbo-aggregate.

Simple operating margin CO_2 emission factor for both energy systems (OES North-West and OES Center) for year 2006 was calculated according to simple OM methodology using amount of produced electricity, fuel consumed, calorific values and CO_2 emission factors at each single power plant in each OES. For calculation are used local values of NCVi and IPCC default values $EF_{CO2,i}$.

Calculation of the baseline emission factor ($EF_{grid,OMsimple,y}$) as the weighted average of the OES North-West baseline emission factor ($EF_{NorthWest,OMsimple,y}$) and the OES Center baseline emission factor ($EF_{Center,OMsimple,y}$):

$$\mathbf{EF_{grid,OMsimple,y} = w_{NorthWest,,y} \times EF_{NorthWest,OMsimple,y} + w_{Center,y} \times EF_{Center,OMsimple,y}}$$

where the weights are:

$w_{NorthWest,,y}$ = 79.6%

$w_{Center,y}$ = 20.4%.

$EF_{NorthWest,OMsimple,y}$ and $EF_{Center,OMsimple,y}$ are calculated as described above and are expressed in tCO_2/MWh.

Calculation of the operating margin emission factors

Table B.1.1. Operating margin emission factor ($EF_{grid,OMsimple,2006}$) calculated according to the simple OM method (ex post option)

	Year	2 006	
		OES North-West	OES Center
Electricity	thous.MWh	34 267	132 330
Emission	tCO_2	21 273 983	72 213 168
$EF_{OMsimple,2006}$	**tCO_2/MWh**	**0.6208**	**0.5457**
weight		**0.796**	**0.204**

Thereby: $EF_{grid,OMsimple,2006} = 0.796 \times 0.6208 + 0.204 \times 0.5457 = \mathbf{0.6055}$

Because operating margin emission factors OES North-West and OES Center were calculated assuming the ex post option, the emissions factors will be calculated again using data vintage of the year in which the project activity displaces grid electricity, requiring to monitor and recalculate the emissions factors annually during the crediting period. If the data required to calculate the emission factor for year *y* is usually only available later than six months after the end of year *y*, alternatively the emission factor of the previous year *(y-1)* may be used.

The cohort of power units to be included in the build margin (BM)

The build margin CO_2 emission factor (**$EF_{grid,BM,y}$**) was calculated from data on amount of produced electricity, fuel consumption, heat content values and CO_2 emission factors for each out of five power plants most recently put in operation:

Table B.1.2. Data on amount of produced electricity, fuel consumption, heat content values and CO_2 emission factors

Power plant	**Year**	**Electricity MWh**	**Emission tCO_2**	**EFBM tCO_2/MWh**
Sotchinskaya TEC	2004	411 195	182 798	0.4446
Tyumenskaya PGU-190/220 st.No.1	2004	777 834	340 028	0.4371
OAO Kaliningradskaya TEC-2	2005	2 468 183	1 076 041	0.4360
GTU TEC LUTCH	2005	318 326	120 607	0.3789
Ivanovskiye PGU	2007	224 292	104 686	0.4667
TOTAL		**4 199 830**	**1 824 160**	**0.4343**

Calculation of the build margin emission factor

The build margin CO_2 emission factor is the generation-weighted average emission factor (tCO_2/MWh) of all power units *m*, during the most recent year y for which power generation data is available, calculated as follows:

$$EF_{grid,BM,y} = \frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

Where:

$EF_{grid,BM,y}$	=	Build margin CO_2 emission factor in year y (tCO_2/MWh)
$EG_{m,y}$	=	Net quantity of electricity generated and delivered to the grid by power unit m in year y (MWh)
$EF_{EL,m,y}$	=	CO_2 emission factor of power unit m in year y (tCO_2/MWh)
m	=	Power units included in the build margin
y	=	Most recent historical year for which power generation data is available

The CO_2 emission factor of each power unit m ($EF_{EL,m,y}$) was determined as for the simple OM, using for y the most recent historical year for which power generation data is available, and using for m the power units included in the build margin.

For estimating of the build margin emission factor the ***Option 2*** has been chosen – the BM emission factor $EF_{grid,BM,y}$ must be updated annually ex-post for the year in which actual project generation and associated emissions reductions occur. The sample group ***m*** consists of the five power plants that have been built within Russia most recently.

Calculation of the combined margin emission factor

The combined margin emissions factor is calculated as follows (Tool to calculate the emission factor for an electricity system ver.01, formula 13):

$$\mathbf{EF_{grid,CM,y} = EF_{grid,OM,y} \times w_{OM} + EF_{grid,BM,y} \times w_{BM}}$$

Where:

$EF_{grid,BM,y}$	=	Build margin CO_2 emission factor in year y (tCO_2/MWh)
$EF_{grid,OM,y}$	=	Operating margin CO_2 emission factor in year y (tCO_2/MWh)
w_{OM}	=	Weighting of operating margin emissions factor (%)
w_{BM}	=	Weighting of build margin emissions factor (%)

As explained above, values used for w_{OM} and w_{BM} are $w_{OM} = 0.5$ and $w_{BM} = 0.5$.

Table B.1.3. Calculated baseline emission factor for grid electricity system (OES North-West + OES Center) $EF_{grid,CM,y}$

Year		2008	2009	2010	2011	2012
$EF_{grid,OM,y}$	tCO_2/MWh	0.6055	0.6055	0.6055	0.6055	0.6055
$EF_{grid,BM,y}$	tCO_2/MWh	0.4343	0.4343	0.4343	0.4343	0.4343
$EF_{grid,CM,y}$	**tCO_2/MWh**	**0.5199**	**0.5199**	**0.5199**	**0.5199**	**0.5199**

Identification of the baseline scenario

Identification of alternatives to the project activity consistent with current laws and Regulations

The alternative baseline scenarios include all possible realistic and credible alternatives that provide outputs or services comparable with the proposed JI project activity (including the proposed project activity without JI benefits), i.e., all type of power plants that could be constructed as alternative to the project activity within the grid boundary:

1/ The project activity not implemented as a JI project (no ERUs sale);

2/ Steam turbine with natural gas fired boiler;

3/ Steam turbine with coal fired boiler;

4/ Steam turbine with biomass fired boiler;

5/ Production of electricity on existing capacities within the relevant electric power system.

Prediction of electricity generation for project and baseline was based on source presented in Table Annex.2.9. (see Annex 2). Regarding baseline, two options were considered:

1/ Capacities of condensing plant (1800 MW) continue working the same number of hours annually regardless the project implementation (approx. 3620 hours). In case of the project, fall in electricity generation on condensing plant (by approx. 1100 thous. MWh) is due to removal of 300 MW steam turbine from energy block No.6 and its inclusion into new turbo-aggregate. The difference in electricity generation will be covered by the project – new turbo-aggregate.

2/ Capacities of condensing plant (1800 MW) will reduce annual working hours from approx. 3620 hours (before the project implementation) to 2596 in 2011 and 2577 hours in 2012. Therefore, in baseline electricity generation on condensing plant falls (approx. from 6515 to 4650 thous. MWh) due to reduced time of operation. Removal of 300 MWe steam turbine from energy block No.6 and its inclusion into new turbo-aggregate in case of the project will be responsible for further drop of electricity generation of 779 and 773 thous. MWh (in 2011 and 2012 respectively). Only this difference in electricity generation due to removal of the steam turbine will be covered by the project.

In case of both options, actual power supply into the grid is lower due to own consumption and related loses (6.4% in total).

Real electricity generation on condensing plant will stay between the two options. As the option 2 leads to lower emission reduction and therefore is more conservative, the option 2 was applied.

Furthermore, in following analysis, CHP plant of Kirishskaya TPP has not been considered because its all parameters remain unchanged whether the project is implemented or not.

Alternative 1 - The proposed project is not undertaken as JI project – two new gas turbine units will be installed with electrical capacity of 287 MW each with subsequent utilization of waste-gas heat in new recovery boilers that will supply steam to one existing steam turbine unit with power output 250 MW. CO_2 emission reduction would not be converted into ERUs. Implementation of the project without being treated as JI would mean drop in income of approx. 372.577/638.702 mln. RUB (10.204/17.493 mln. € at price 7 and 12 €/t ERU respectively; against Alternative 5) within period 2008-2012.

Table B.1.4. Alternative 1 parameters

Indicators	**Unit**	**2008**	**2009**	**2010**	**2011**	**2012**
Investment costs	mil. €	365.020				
Natural gas consumption	thous.m^3	1 509 180	1 505 848	1 389 631	1 714 514	1 708 034
HFO consumption	t	291 347	290 703	268 268	173 966	172 715
Electricity output	MWh	6 104 030	6 090 552	5 620 500	7 856 784	7 830 576
NG EF CO_2	tCO_2/TJ	56.1	56.1	56.1	56.1	56.1
HFO EF CO_2	tCO_2/TJ	77.3	77.3	77.3	77.3	77.3
TPP - CO_2 emission	tCO_2	3 723 494	3 715 272	3 428 538	3 749 743	3 733 756
Replaceable electricity	MWh	0	0	0	0	0
Combined EF CO_2	tCO_2/MWh	0.5199	0.5199	0.5199	0.5199	0.5199
CO_2 emission-repl.electricity	tCO_2	0	0	0	0	0
CO_2 emission (Alternative 1)	**tCO_2**	**3 723 494**	**3 715 272**	**3 428 538**	**3 749 743**	**3 733 756**

Alternative 2 - Installation of new steam turbines together with gas boilers within 2007-2010. Total quantity of power produced by new steam turbines will be the same as quantity of power produced by gas turbine units installed under the project. The existing equipment will continue operation with current capacity. Electricity production in TPP will be therefore the same as with the project. The emissions of CO_2 in consequence of higher consumption of natural gas and heavy fuel oil will be higher than in project.

Table B.1.5. Alternative 2 parameters

Indicators	**Unit**	**2008**	**2009**	**2010**	**2011**	**2012**
Investment costs	mil. €	68.470				
Natural gas consumption	thous.m^3	1 509 180	1 505 848	1 389 631	1 942 537	1 936 057
HFO consumption	t	291 347	290 703	268 268	375 006	373 755
Electricity output	MWh	6 104 030	6 090 552	5 620 500	7 856 784	7 830 576
NG EF CO_2	tCO_2/TJ	56.1	56.1	56.1	56.1	56.1
HFO EF CO_2	tCO_2/TJ	77.3	77.3	77.3	77.3	77.3
TPP - CO_2 emission	tCO_2	3 723 494	3 715 272	3 428 538	4 792 684	4 776 697
Replaceable electricity	MWh	0	0	0	0	0
Combined EF CO_2	tCO_2/MWh	0.5199	0.5199	0.5199	0.5199	0.5199
CO_2 emission-repl.electricity	tCO_2	0	0	0	0	0
CO_2 emission (Alternative 2)	**tCO_2**	**3 723 494**	**3 715 272**	**3 428 538**	**4 792 684**	**4 776 697**

Alternative 3 - Installation of new steam turbines together with coal fired boilers (fluid bed) within 2007-2010. Total quantity of power produced by new steam turbines will be the same as quantity of power produced by gas turbine units installed under the project. The existing equipment will continue operation with current capacity. Electricity production in Kirishskaya TPP will be therefore the same as with the project. The emissions of CO_2 in consequence of consumption of coal will be much higher than in other alternatives.

Table B.1.6. Alternative 3 parameters

Indicators	Unit	2008	2009	2010	2011	2012
Investment costs	mil. €	686.500				
Natural gas consumption	thous.m^3	1 509 180	1 505 848	1 389 631	1 081 378	1 073 463
HFO consumption	t	291 347	290 703	268 268	208 760	207 232
Coal consumption	t	0	0	0	1 686 163	1 688 972
Electricity output	MWh	6 104 030	6 090 552	5 620 500	7 856 784	7 830 576
NG EF CO_2	tCO_2/TJ	56.1	56.1	56.1	56.1	56.1
HFO EF CO_2	tCO_2/TJ	77.3	77.3	77.3	77.3	77.3
Coal EF CO_2	tCO_2/TJ	94.5	94.5	94.5	94.5	94.5
TPP - CO_2 emission	tCO_2	3 723 494	3 715 272	3 428 538	5 995 249	5 981 265
Replaceable electricity	MWh	0	0	0	0	0
Combined EF CO_2	tCO_2/MWh	0.5199	0.5199	0.5199	0.5199	0.5199
CO_2 emission-repl.electricity	tCO_2	0	0	0	0	0
CO_2 emission (Alternative 3)	**tCO_2**	**3 723 494**	**3 715 272**	**3 428 538**	**5 995 249**	**5 981 265**

Alternative 4 - Installation of new steam turbines together with biomass (wood/wood waste) fired boilers within 2007-2010. Total quantity of power produced by new steam turbines will be the same as quantity of power produced by gas turbine units installed under the project. The existing equipment will continue operation with current capacity. Electricity production in Kirishskaya TPP will be therefore the same as with the project. The emissions of CO_2 in consequence of consumption of biomass (wood/wood waste) will be much lower than in other alternatives and in project, too.

Table B.1.7. Alternative 4 parameters

Indicators	Unit	2008	2009	2010	2011	2012
Investment costs	mil. €	n.a.				
Natural gas consumption	thous.m^3	1 509 180	1 505 848	1 389 631	1 081 378	1 073 463
HFO consumption	t	291 347	290 703	268 268	208 760	207 232
Biomass consumption	t	0	0	0	2 279 779	2 283 577
Electricity output	MWh	6 104 030	6 090 552	5 620 500	7 856 784	7 830 576
NG EF CO_2	tCO_2/TJ	56.1	56.1	56.1	56.1	56.1
HFO EF CO_2	tCO_2/TJ	77.3	77.3	77.3	77.3	77.3
Biomass EF CO_2	tCO_2/TJ	0	0	0	0	0
TPP - CO_2 emission	tCO_2	3 723 494	3 715 272	3 428 538	2 668 007	2 648 480
Replaceable electricity	MWh	0	0	0	0	0
Combined EF CO_2	tCO_2/MWh	0.5199	0.5199	0.5199	0.5199	0.5199
CO_2 emission-repl.electricity	tCO_2	0	0	0	0	0
CO_2 emission (Alternative 4)	**tCO_2**	**3 723 494**	**3 715 272**	**3 428 538**	**2 668 007**	**2 648 480**

Alternative 5 - Electricity production will continue in Kirishskaya TPP with current capacity and the required quantity of electricity for consumption will be provided by the existing equipment of Kirishskaya TPP and other power plants of the OES North-West and OES Center.

Table B.1.8. Alternative 5 parameters

Indicators	**Unit**	**2008**	**2009**	**2010**	**2011**	**2012**
Investment costs	mil. €	0				
Natural gas consumption	thous.m^3	1 509 180	1 505 848	1 389 631	1 081 378	1 073 463
HFO consumption	t	291 347	290 703	268 268	208 760	207 232
Electricity output	MWh	6 104 030	6 090 552	5 620 500	4 373 741	4 341 730
NG EF CO_2	tCO_2/TJ	56.1	56.1	56.1	56.1	56.1
HFO EF CO_2	tCO_2/TJ	77.3	77.3	77.3	77.3	77.3
TPP - CO_2 emission	tCO_2	3 723 494	3 715 272	3 428 538	2 668 007	2 648 480
Replaceable electricity	MWh	0	0	0	3 483 043	3 488 846
Combined EF CO_2	tCO_2/MWh	0.5199	0.5199	0.5199	0.5199	0.5199
CO_2 emission-repl.electricity	tCO_2	0	0	0	1 810 860	1 813 877
CO_2 emission (Alternative 5)	**tCO_2**	**3 723 494**	**3 715 272**	**3 428 538**	**4 478 868**	**4 462 358**

<u>*Identification of plausible baseline scenarios*</u>

Alternative 1 - The proposed project is not undertaken as JI project - it would mean drop in income of approx. 372.577/638.702 mln. RUB (10.204/17.493 mln. € at price 7 and 12 €/t ERU respectively) within period 2008-2012. Such a shortfall would affect the project adversely during start phase.

Alternative 2 - Installation of new steam turbines together with gas boiler within 2007-2010. Total quantity of power produced by new steam turbines will be the same as quantity of power produced by gas turbine units installed under the project. The main barrier in becoming the Alternative 2 a baseline is less efficient electricity generation compared to gas turbines (with the relative high investment costs of steam turbines). The emissions of CO_2 in consequence of higher consumption of natural gas and heavy fuel oil will be higher than in project.

Alternative 3 - Installation of new steam turbines together with coal fired boilers (fluid bed) within 2007-2010. Total quantity of power produced by new steam turbines will be the same as quantity of power produced by gas turbine units installed under the project. The existing equipment will continue operation with current capacity.
Main barriers in becoming the Alternative 3 a baseline are the high investment costs of fluid boiler, less efficient electricity generation by steam turbines compared to gas turbines and longer time period required for completion of the construction.
Based on economic evaluation (current fuel prices) this alternative is not better than combined cycle gas turbine plant of same capacity. Regarding the fluid blocks construction, the project design, building of infrastructure for solid fuel delivery, storage and manipulation and disposal site for ash and other solid waste is highly time consuming. Therefore, it is not likely that new power plant would be put in operation in 2011.

Alternative 4 - Installation of new steam turbines together with biomass (wood/wood waste) fired boiler within 2007-2010. Total quantity of power produced by new steam turbines will be the same as quantity of power produced by gas turbine units installed under the project. The existing equipment will continue operation with current capacity.
Except less efficient electricity generation of steam turbines compared to gas turbines, the main barriers in becoming the Alternative 4 a baseline are following:
There is in fact no infrastructure for biomass supply existing in Russia. Waste wood produced at wood processing enterprises does not reach quality necessary for utilisation in power industry. In addition, no sources of biomass in required quantity (2.3 mln. tonnes per year to produce 3 483 GWh) are currently available and would not be created within 2-3 years time horizon.
Furthermore, there is absent capacity of machinery industry to supply needed equipment in Russia and imported equipment is too expensive. Equipment on the market is not available in big enough capacities (above 30 MW only exceptionally).
Due to above reasons, biomass boilers are not often installed in Russia (almost never, in fact). Biomass boiler(s) construction therefore could not be considered as a realistic alternative.

Alternative 5 - Electricity production will continue in Kirishskaya TPP with current capacity and the required quantity of electricity for consumption will be provided by the existing equipment of Kirishskaya TPP and other power plants of the OES North-West and OES Center. The main drawback of Alternative 5 is less efficient electricity generation of the whole OES North-West and OES Center compared to gas turbines and increasing dependence on electricity from public grid. Nevertheless, the latter would not play significant role because electricity could be easily supplied to consumers from public grid. As an advantage, the Alternative 5 involves nearly zero investment cost and no change in operations including maintenance.

Conclusion
All alternative baseline scenarios are in compliance with all applicable legal and regulatory requirements. However, **Alternative 4** is not realistic due to existing barriers (lacking infrastructure) and thus excluded from consideration under investment analysis.

Identification the economically most attractive baseline scenario alternative

The economically most attractive baseline scenario alternative is identified using investment analysis. For the baseline scenario alternative has been applied Investment comparison analysis based on the IRR, NPV during 15-years period. In this case a discount rate of 10 % is used, the annual rate of inflation 8.5 %.

Table B.1.9. Key information used to assess the different baseline alternatives

Parameters	**Unit**	**2008**	**2009**	**2010**	**2011**	**2012**
Natural Gas	EUR/1000 m^3	68.7	87.7	112.0	142.2	153.6
Heavy fuel oil	EUR/t	140.7	153.4	168.7	178.9	193.2
Hard coal	EUR/t	33.0	35.5	38.1	40.7	42.9
Electricity	EUR/MWh	34.2	40.6	51.7	59.4	66.7
Electricity Output Alt.1	MWh/year	6 104 030	6 090 552	5 620 500	7 856 784	7 830 576
Electricity Output Alt.2	MWh/year	6 104 030	6 090 552	5 620 500	7 856 784	7 830 576
Electricity Output Alt.3	MWh/year	6 104 030	6 090 552	5 620 500	7 856 784	7 830 576
Electricity Output Alt.5	MWh/year	6 714 433	6 699 607	6 182 550	4 811 115	4 775 903

There were four alternatives considered for baseline emission estimation, i.e. in absence of the project:

Alternative 1: The project activity not implemented as a JI project (no ERUs sale);
Alternative 2: Steam turbines with natural gas fired boilers;
Alternative 3: Steam turbines with coal fired boilers;
Alternative 5: Production of electricity on existing capacities within the OES North-West and OES Center

Alternative 1 - The proposed project is not undertaken as JI project

Table B.1.10. Alternative 1 analysis

	IRR	NPV	Pay-back (years)
Alternative 1	34.4%	1 094 mln. €	6

Table B.1.11. Sensitivity analysis of IRR – Alternative 1

Parameter	Fluctuation				
	-10%	-5%	0%	5%	10%
Investment costs	37.4%	35.8%	34.4%	33.0%	31.8%
Fuel costs	39.5%	36.9%	34.4%	31.9%	29.5%
Electricity price	25.9%	30.1%	34.4%	38.5%	42.7%
Production elect.	30.7%	32.5%	34.4%	36.2%	38.0%

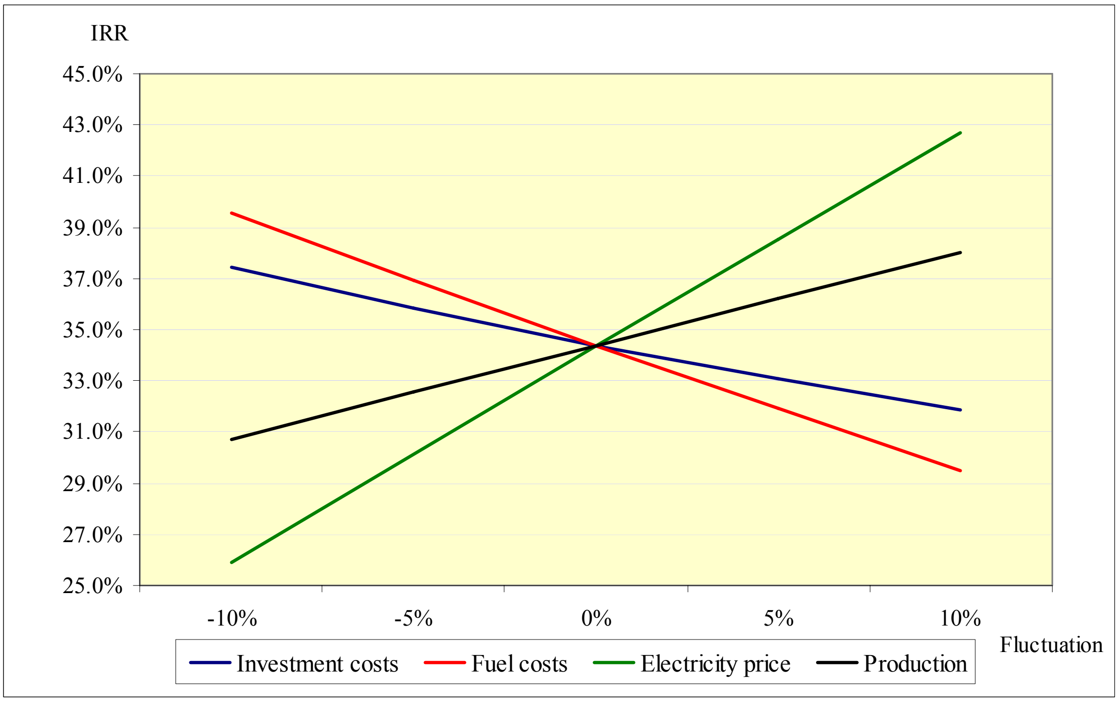


Figure B.1.1. Sensitivity analysis

Sensitivity analysis was applied to evaluate sensitivity of the Alternative 1 to changes that might occur during its implementation and operation.
Analysis of the investment cost within range -10% and +10% showed that IRR changes within 37.4%-31.8%. These values are higher than usual Russian commercial banks' loan interest rate 12% and slightly lower than IRR in the project.
Another factor that might influence IRR and NPV of the alternative is change of price of fuels above projected price range. Based on analysis, IRR values range from 39.5% to 29.5% (without ERUs sale) within -10% and +10% change of fuels price. The conclusion is the same as in above case.
Changes of electricity sale price affect IRR and NPV the opposite way as it is in the case of investment cost change and fuels price change. The range of IRR change (25.9%-42.7%, without ERUs sale) indicates that the Alternative 1 is most sensitive to change of electricity price. The price of electricity in 2007 was 1 044 RUB/MWh.

Alternative 2 - Installation of new steam turbines together with gas boilers within 2007-2010. Total quantity of power produced by new steam turbines will be the same as quantity of power produced by gas turbine units installed under the project. The existing equipment will continue operation with current capacity. Electricity production in Kirishskaya TPP will be therefore the same as in the project.

Table B.1.12. Alternative 2 analysis

	IRR	NPV	Pay-back (years)
Alternative 2	131.6%	964.65 mln. €	2

Table B.1.13. Sensitivity analysis of IRR – Alternative 2

Parameter	Fluctuation				
	-10%	-5%	0%	5%	10%
Investment costs	160.7%	144.3%	131.6%	121.3%	112.9%
Fuel costs	263.8%	178.8%	131.6%	101.4%	80.2%
Electricity price	52.0%	80.8%	131.6%	272.0%	2259.9%
Production elect.	110.8%	121.2%	131.6%	141.9%	152.3%

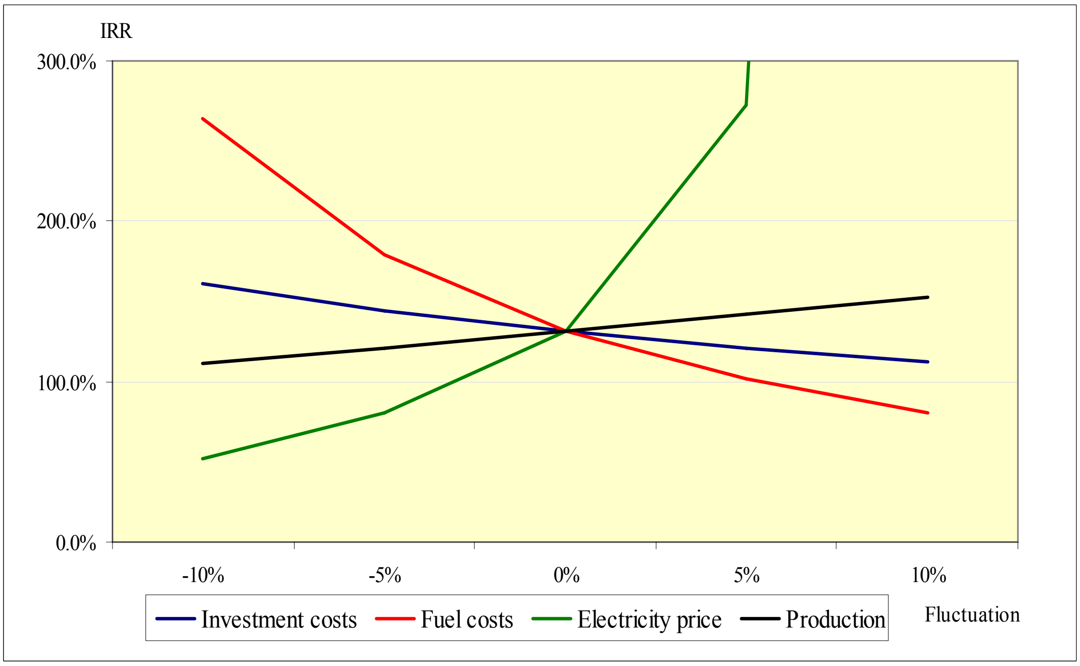


Figure B.1.2. Sensitivity analysis baseline scenario

Analysis of the investment cost within range -10% and +10% showed that IRR changes within 160.7% - 112.9%. These values are significantly higher in all range of fluctuation than IRR in project and usual Russian commercial banks' loan interest rate 12%, too.
Based on analysis of fuel (natural gas) price change above considered price range (-10% and +10%), IRR values range from 263.8% to 80.2%. Similarly, in the case electricity price change (-10% and +10%), IRR values range from 52.0% to 2259.9%. Large range of IRR change indicates that alternative 2 is most sensitive to changes of fuel and electricity price.

Alternative 3 - Installation of new steam turbines together with coal fired boilers within 2007-2010. Total quantity of power produced by new steam turbines will be the same as quantity of power produced by gas turbine units installed under the project. The existing equipment will continue operation with current capacity. Electricity production in Kirishskaya TPP will be therefore the same as in the project.

Table B.1.14. Alternative 3 analysis

	IRR	NPV	Pay-back (years)
Alternative 3	18.5%	625.77 mln. €	9

Table B.1.15. Sensitivity analysis of IRR – Alternative 3

Parameter	Fluctuation				
	-10%	-5%	0%	5%	10%
Investment costs	20.3%	19.4%	18.5%	17.7%	17.0%
Fuel costs	20.6%	19.6%	18.5%	17.5%	16.4%
Electricity price	12.6%	15.6%	18.5%	21.3%	24.1%
Production elect.	15.9%	17.2%	18.5%	19.7%	21.0%

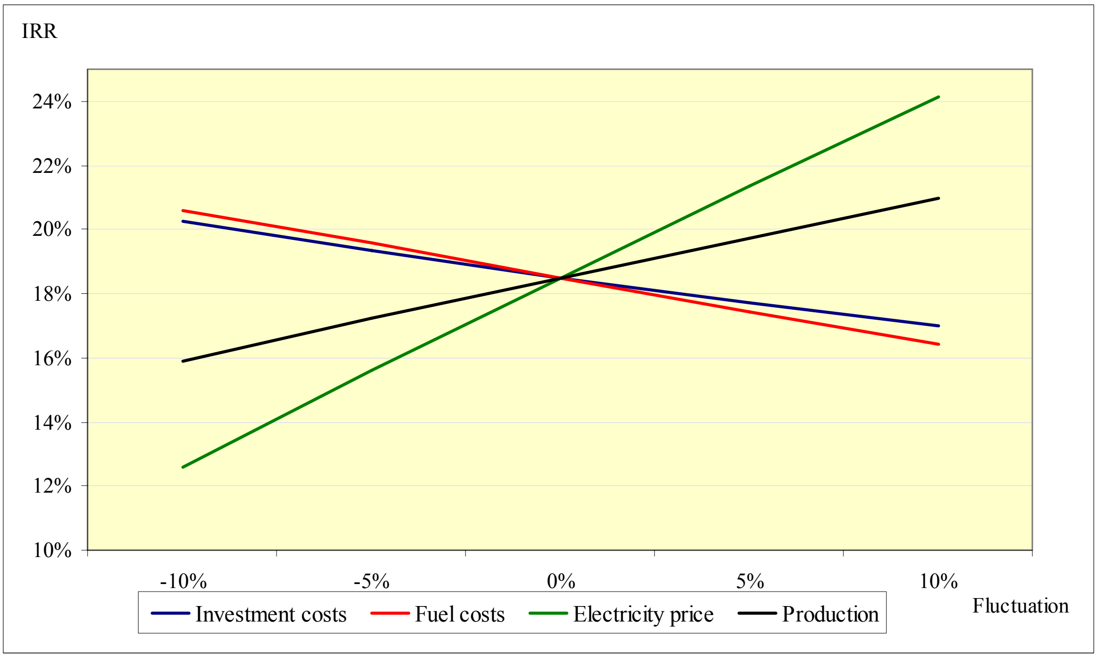


Figure B.1.3. Sensitivity analysis baseline scenario

Analysis of the investment cost within range -10% and +10% showed that IRR changes within 20.3%-17.0%. These values are higher in all range of fluctuation than usual Russian commercial banks' loan interest rate 12%. Based on analysis of fuels (natural gas and coal) price change within considered price range (-10% and +10%), IRR values range from 20.6% to 16.4%. In the case electricity price change (-10% and +10%), IRR values range from 12.6% to 24.1%. Similarly, as in the case of Alternative 1 and 2, Alternative 3 is most sensitive to changes of electricity price.

Alternative 5 - Electricity production will continue in Kirishskaya TPP with current capacity and the required quantity of energy for consumption will be provided by the existing equipment of Kirishskaya TPP and other power plants of the OES North-West and OES Center.

Table B.1.16. Alternative 5 analysis

	IRR	NPV
Alternative 5	n.a.	538.62 mln. €

Under this alternative the investment costs are not envisaged, therefore assessment of the alternative based on the efficiency indexe (IRR) cannot be carried out.

Table B.1.17. Sensitivity analysis of NPV – Alternative 5

Parameter	Fluctuation				
	-10%	-5%	0%	5%	10%
Fuel costs	673.960	606.291	538.623	470.954	403.285
Electricity price	281.817	410.795	538.623	666.450	794.277
Production elect.	455.587	497.105	538.623	580.140	621.658

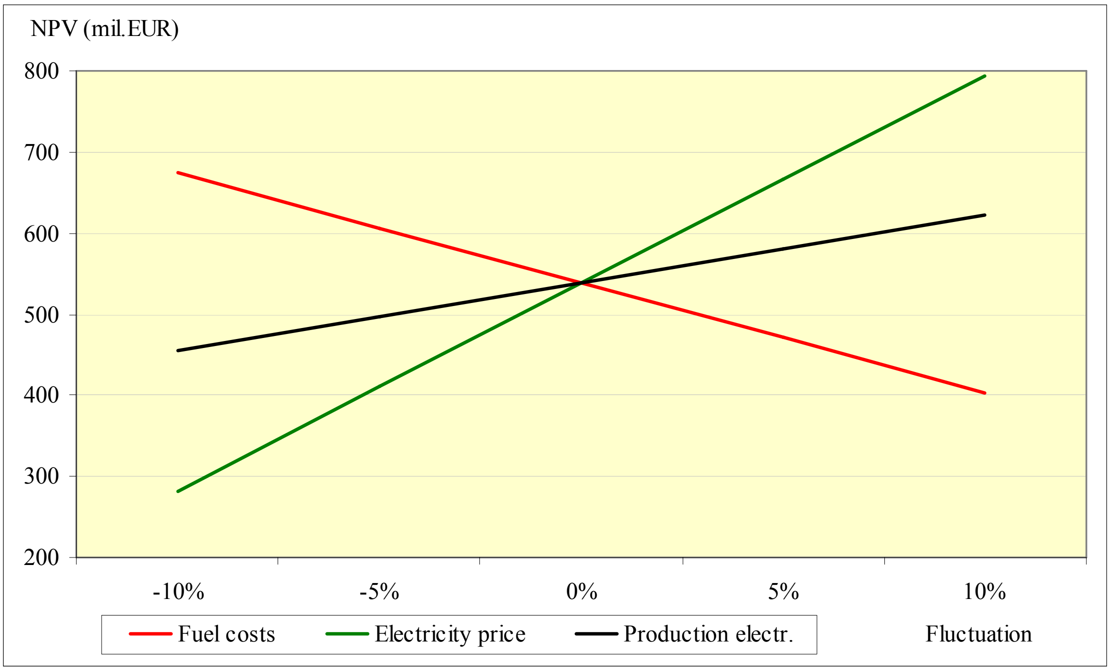


Figure B.1.4. Sensitivity analysis of NPV – Alternative 5

NPV is in case of Alternative 5 sensitive to electricity price.

The levelized cost of electricity production

The levelized cost of electricity production in (€/MWh) in alternatives 1,2,3,5 should be considered as financial indicator, too.

Table B.1.18. The levelized cost of electricity production

	Constant annual cost value (C_0) (thous. €)	Electricity production (thous. MWh/y)	Levelized cost of electricity production (€/MWh)
Alternative 1	511 189.6	7 830.6	65.28
Alternative 2	526 652.1	7 830.6	67.26
Alternative 3	567 164.7	7 830.6	72.43
Alternative 5	337 749.7	4 341.7	77.79

Table B.1.19. All considered alternatives - indicators summary

	IRR (%)	NPV (mln. €)	Pay-back (years)	Levelized cost of electricity production (€/MWh)	CO_2 emission (tCO_2)
Alternative 1	34.4	1 094.00	6	65.28	18 350 804
Alternative 2	131.6	964.65	2	67.26	20 436 686
Alternative 3	18.5	625.77	9	72.43	22 843 818
Alternative 5	n.a.	538.62	n.a.	77.79	19 808 530

Conclusion

The IRR and NPV for Alternative 3 is lower than for Alternative 2 and for Alternative 1, too.
The IRR for Alternative 2 is higher than for the Alternative 1 (IRR: 131.6% against 34.4%) and NPV is lower (964.65 mln.€ against 1 094.00 mln.€).
Levelized cost of electricity production is highest in Alternative 3 and 5.
GHG emissions in Alternative 1, 2 and 5 are lower as in Alternative 3. In Alternatives 2, 3 and 5 lower efficiency equipment would work (steam condensation turbines) producing electricity with lower efficiency than in the Alternative 1.

Based on the efficiency index IRR, Alternatives 1 and 3 are not that attractive as Alternative 2.
From point of view of NPV the Alternative 5 has lovest value, having at the same time highest levelized cost of electricity production.

In case of Alternative 5 the investment costs are not envisaged, therefore comparison of IRR cannot be performed. Absence of the investment costs will be the dominant factor there. It is explained by specificity of the power sector of the Russian Federation. The prices for heat and electricity are regulated by the State, therefore, in most cases the expenses for construction or retrofitting of the plants are compensated hardly or are not compensated quite. This fact is confirmed by the following: currently about 40 % of installed electrical capacity of turbo units of the thermal power plants of RAO “UES of Russia” has been exceeded of its lifetime in accordance with equipment certificate. In the existing conditions the customary practice is overhauling of renewal period of the equipment. Avoiding investment costs is obviously attractive option and Alternative 5 is thereby highly attractive.

Thus, Alternative 2 and Alternative 5 are justified as the most financially/economically attractive although their comparison cannot be fully conclusive.

Pursuant to methodology AM0029, in such a case, the baseline scenario alternative with the lowest emission rate among the alternatives that are the most financially and/or economically attractive (i.e. Alternatives 2 and 5) should be selected:

Table B.1.20. Emission rate (gCO_2/kWh)

	unit	2008	2009	2010	2011	2012
Alternative 2	gCO_2/kWh	610.0	610.0	610.0	**610.0**	**610.0**
Alternative 5	gCO_2/kWh	610.0	610.0	610.0	**570.1**	**569.9**

Within Alternative 5 electricity production will continue in Kirishskaya TPP with current capacity and the required increased quantity of energy for consumption will be provided by the existing equipment of Kirishskaya TPP and other power plants of the OES North-West and OES Center. Under this alternative the investment costs are not envisaged. From year, when the project is expected to start operation (2011), CO_2 emission rate is lower at Alternative 5 by more than 6.5 % against Alternative 2. Emission rate will decrease within Alternative 5 due to satisfying of growing electricity demand by higher electricity generation within OES North-West and OES Center at better efficiency as is reached in Kirishskaya TPP on steam turbines where electricity is supplied to the grid and heat is not exploited (Condensing Plant).
Emission rate does not change within Alternative 2 as addition of new steam turbines to existing steam turbines does not affect efficiency.

Based on thorough considerations (thereinbefore) the **Alternative 5** appears being most plausible scenario in absence of the project and therefore representing **baseline scenario**.

Table B.1.21. Baseline CO_2 emissions

Parameters	Years					
	Unit	2008	2009	2010	2011	2012
TPP - CO_2 emission	tCO_2	3 723 494	3 715 272	3 428 538	2 668 007	2 648 480
CO_2 emission-repl.electricity	tCO_2	0	0	0	1 810 860	1 813 877
Baseline CO_2 emission	**tCO_2**	**3 723 494**	**3 715 272**	**3 428 538**	**4 478 868**	**4 462 358**

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

The anthropogenic emissions of greenhouse gases are reduced due to lower CO_2 emissions in case of project activity against higher CO_2 emissions in case of baseline scenario – production of the same quantity of electricity on power plants working within OES North-West and OES Center.

Justification of distinction between baseline and the project activity is done through the assessment of additionality. The assessment of additionality comprises the following steps:
Step 1: Investment analysis
Step 2: Common practice analysis
Former Step 3: Impact of CDM (JI) registration – request to evaluate impact of CDM registration (here the project treatment under JI mechanisms) as substance of the step 5 of Tool for the demonstration and assessment of additionality was removed from the Tool by EB 29 (February 2007) and therefore no longer obtains.

Identification of alternatives to the project activity consistent with current laws and regulations:

1/ The project activity not implemented as a JI project (no ERUs sale);

2/ Steam turbine with natural gas fired boiler;

3/ Steam turbine with coal fired boiler;

4/ Steam turbine with biomass fired boiler;

5/ Production of electricity on existing capacities within the relevant electric power system.

As concluded above (B.1.), all alternative scenarios are in compliance with all applicable legal and regulatory requirements. However, **Alternative 4** is not realistic due to existing barriers (lacking infrastructure) and thus excluded from consideration under investment analysis.

Step 1: Investment analysis

Sub-steps are numbered in accordance with "Tool for the demonstration and assessment of additionality" version 04.

Sub-step 2b. Option II: Investment comparison analysis
The IRR is identified as most suitable indicator for the project.
As the IRR is an indicator of the efficiency of an investment, it is considered as best tool for comparison of alternate investments (investing in other projects). The IRR is used as significant parameter in decision-making by investing company.

Sub-step 2c. Calculation and comparison of financial indicators
Investment comparison analysis based on the IRR, NPV during 15-years period has been applied for the project activity. In this case a discount rate of 10 % is used, the annual rate of inflation 8.5 %. The total cost of the project is € 365.020 mln. (exchange rate of Central Bank of Russia 36.5125 RUB/€ as of 4 March 2008). Income from ERUs sales is 10.204/17.493 mln. € at price 7 and 12 €/t ERU (Alternative 5 assumed as baseline scenario) within period 2008-2012.

Parameters used to assess different scenarios are listed in table B.1.9. above and at individual alternatives.

Table B.2.1. The IRR and NPV analysis results – the project

ERU price	IRR	NPV
7 €/t ERU	34.6%	1 099.56 mln. €
12 €/t ERU	34.7%	1 103.53 mln. €

The obtained indicators generally confirm that the project is viable. These figures show that the revenue from the sale of ERUs improves economic indicators NPV and IRR of the project.

Such up-to-date technique as planned gas turbines is far more expensive than other commonly used techniques. Income from ERUs sale is therefore relatively small. However, income from ERUs sale improves financial status and significantly facilitates implementation of the project especially during beginning phase when large volume of financial means is needed within relatively short period of time.

Table B.2.2. Sensitivity analysis – the project

Parameter	Fluctuation				
	-10%	-5%	0%	5%	10%
Project analysis IRR (with ERUs sales at 12 €/t ERU)					
Investment costs	37.8%	36.2%	34.7%	33.4%	32.1%
Fuel costs	39.9%	37.3%	34.7%	32.2%	29.8%
Electricity price	26.2%	30.5%	34.7%	38.9%	43.0%
Production elect.	31.4%	33.0%	34.7%	36.3%	38.0%

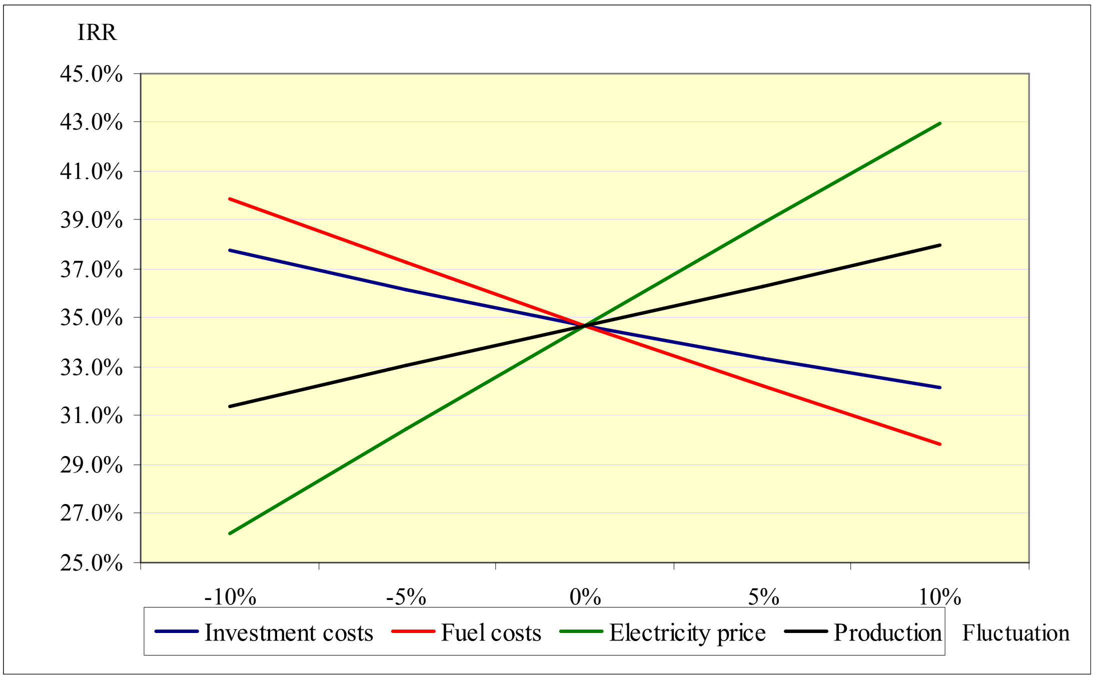


Figure B.2.1. Sensitivity analysis – the project

Sensitivity analysis was applied to evaluate sensitivity of the project to changes that might occur during project implementation and operation.

Analysis of the investment cost within range -10% and +10% showed that IRR changes within 37.8%-32.1%. These values are higher than usual Russian commercial banks' loan interest rate 12%. Therefore, the project is considered to be viable and will generate sufficient income even in the case of financing the project by loan and brings profit even if above changes of investment cost occur.

Another factor that might influence project's IRR and NPV is change of price of fuels above projected price range. Based on analysis, IRR ranges from 39.9% to 29.8% within -10% and +10% change of fuel price. The conclusion is the same as in above case.

Electricity is produced by the project after its implementation, therefore changes of electricity price affect project's IRR and NPV the opposite way as it is in the case of investment cost change and fuels price change. The range of IRR change (26.2%-43.0%) indicates that project is sensitive to change of electricity price. The price of electricity in 2007 was 1 044 RUB/MWh. As it is widely forecasted, price of electricity and natural gas will grow. If natural gas price grows significantly, increased expenses will be compensated by increased electricity prices.

Table B.2.3. The project and considered alternatives - indicators summary

	ERU price (€/t ERU)	IRR (%)	NPV (mln. €)	Levelized cost of electricity production (€/MWh)
Project	7.00	34.6	1 099.56	65.15
Project	12.00	34.7	1 103.53	65.06
Alternative 1	n.a.	34.4	1 094.00	65.28
Alternative 2	n.a.	131.6	964.65	67.26
Alternative 3	n.a.	18.5	625.77	72.43
Alternative 5	n.a.	n.a.	538.62	77.79

Conclusion: The Alternative 2 has significantly higher IRR than the project, therefore the JI project activity can not be considered as the most financially attractive.

Step 2: Common practice analysis

The dominant technique in the Russian power sector is the Rankine cycle employing steam turbines. In Russia the share of gas turbines amounts only 1.4 % (2006) of total capacities of the power plants. Consequently, the proposed project activity is not widely diffused practice in the Russian power sector.
For example, at projected growth of electricity demand in OES Center it is expected that share of coal fired condensing power plants on electricity production will grow as well. Until 2010, coal fired power plants production will increase 2.1 times against year 2005 at 20% increase of installed capacity. Therefore, penetration of combined cycle gas turbine power stations will not be higher than marginal.
There are several similar activities under preparation in Russia, but as far as known all of them attempt to gain resources within JI mechanism.

Conclusion: Occassionaly similar activities are observed, but they strive to get JI status as well. Activity similar to the project but not treated as JI is not common practice, therefore the project is additional.

CONCLUSION

As both steps 1 and 2 are satisfied, the project is considered additional.

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

The spatial extent of the project boundary includes the project site and all power plants connected physically to the baseline grid as defined in "Tool to calculate emission factor for an electricity system".

Present electricity production is carried out in boundaries of energy systems. The energy system is a complex of jointly working power plants and networks, with the general mode of operation and the centralized dispatching management.

The basic part of Russia energy systems is incorporated for parallel work within the limits of OES (Consolidated Energy Systems) and UES of Russia. There are six Consolidated Energy Systems in structure of UES of Russia: Center, Srednaya Volga (=Middle Volga), Ural, North-West, Yuga (=South) and Siberia. OES of Far East works separately from UES of Russia.

Fig. B.3.1. Scheme of UES of Russia as divided into the Consolidated Energy Systems (Russian: Obyedinennye energosistemy - OES)

The spatial extent of the project boundary includes the project site and all power plants connected physically to the electricity system that the JI project power plant is connected to which is represented by set of power plants grouped in OES North-West, thus all fossil fuel power plants within OES North-West were included into project boundaries. Furthermore, as OES North-West imports power from OES Center, after project implementation import will drop and certain amount of electricity produced in OES Centre is replaced by Kirishskaya TPP production. Therefore, OES Center fossil fuel power plants are included into project boundaries, too.

Set of 30 fossil fuel power plants within OES North-West was selected out of regional generating companies from Arkhangelskoe RDU, Karelskoe RDU, Kolskoe RDU, Komi RDU, Leningradskoe RDU, Novgorodskoe RDU, Vologodskaya oblast and Pskovskaya oblast. Low-cost power plants preferably connected to grid (renewable energy sources) were not included in selection.

Total capacity of sources within OES North-West is 12 266.6 MW. Installed capacity of selected fossil fuel power plants is 10 766 MW (51.5%), capacity of nuclear, hydro and biomass power plants is 8 618.3 MW (41.3%). Remaining capacity belongs to industrial power plants with capacity 1 500.9 MW (7.2%).

Regarding OES Center, set of 77 fossil fuel power plants was considered. Low-cost/must-run power plants preferably connected to grid were not included in selection. Total capacity of sources within OES Center is 49 312 MW. Installed capacity of considered fossil fuel power plants is 32 499 MW (66%), capacity of nuclear, hydro and biomass power plants (i.e. low-cost/must-run sources) is 14 099 MW (28%). Remaining capacity belongs to industrial power plants with capacity 2 715 MW (5.5%).

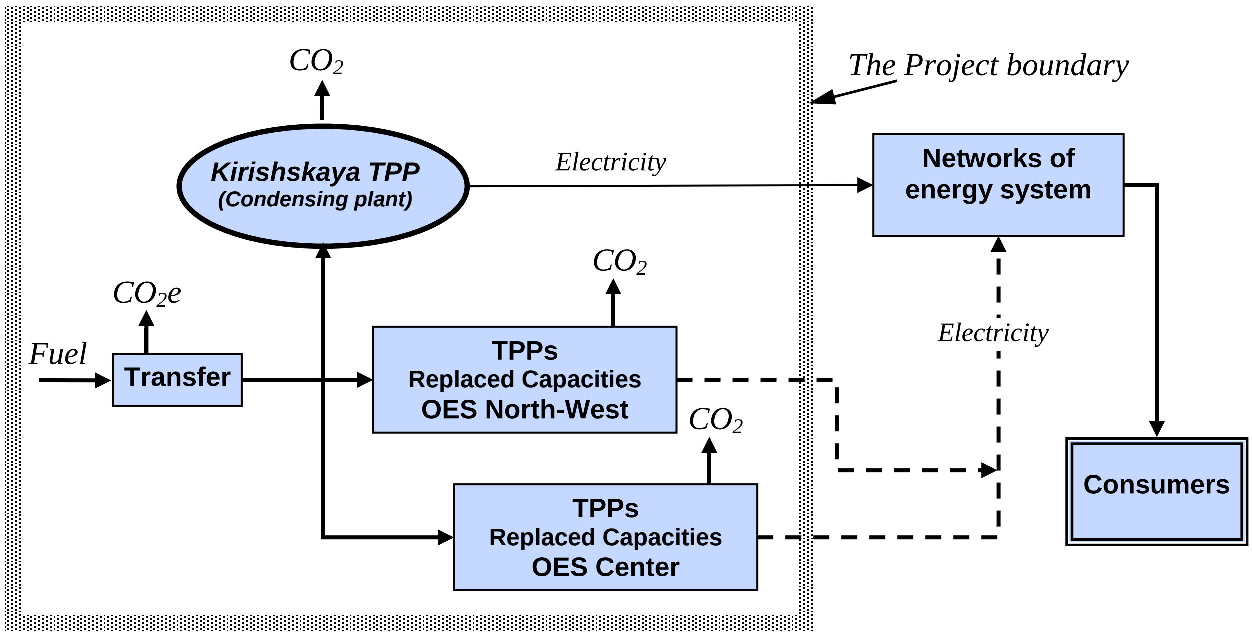


Figure B.3.2. Project boundary

The greenhouse gases included in or excluded from the project boundary are shown in Table 3.1.

Table B.3.1. Overview of emissions sources included in or excluded from the project boundary

	Source	Gas	Included?	Justification / Explanation
Baseline	Power generation in baseline	CO_2	Yes	Main emission source
		CH_4	No	Excluded for simplification. This is conservative.
		N_2O	No	Excluded for simplification. This is conservative.
Project Activity	On-site fuel combustion due to the project activity	CO_2	Yes	Main emission source
		CH_4	No	Excluded for simplification.
		N_2O	No	Excluded for simplification.

See Table 1 in AM0029 ver.02

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

Date of completion of the PDD: July 29, 2008

Name of person/entity determining the baseline:

- JSC "Sixth Wholesale Power Market Generating Company" (WGC-6)
- ECF Project

See Annex 1 for detailed contact information.

SECTION C. Duration of the project / crediting period

C.1. Starting date of the project:

01.01.2011

C.2. Expected operational lifetime of the project:

Lifetime of the existing equipment of Kirishskaya TPP will allow exploiting of it till 2012.
Lifetime of the new gas turbines is 15 years.
Therefore equipment lifetime does not determine the emission reductions by project.

For calculation of financial parameters period of activity 15 years was used.

C.3. Length of the crediting period:

2 years (24 months from 1 January 2011 to 31 December 2012).

SECTION D. Monitoring plan

D.1. Description of monitoring plan chosen:

All data collected as part of monitoring should be archived electronically and be kept at least for 2 years after the end of the last crediting period. 100% of the data should be monitored if not indicated otherwise in the tables below. All measurements should be conducted with calibrated measurement equipment according to relevant industry standards. Some parameters listed below under "data and parameters" either need to be monitored continuously during the crediting period or need to be calculated only once for the crediting period, depending on the data vintage chosen, following the provisions in the baseline methodology procedure outlined above and the guidance on "monitoring frequency" for the parameter.
The calculation of the operating margin and build margin emission factors are documented electronically in a spreadsheet that are attached to the JI-PDD. This should include all data used to calculate the emission factors, including:

- For grid-connected power plant the following information:
    - Information to clearly identify the plant;
    - The date of commissioning;
    - The capacity (MW);
    - The fuel type(s) used;
    - The quantity of net electricity generation in the relevant year(s);
    - If applicable: the fuel consumption of each fuel type in the relevant year(s);
    - Information whether the plant / unit is a low-cost / must-run plant /unit;
- Net calorific values used;
- CO_2 emission factors used;
- Plant efficiencies used;
- Identification of the plants included in the build margin and the operating margin during the relevant time year(s);

The data should be presented in a manner that enables reproducing of the calculation of the build margin and operating margin grid emission factor.

Requirements for fuel accounting
The fuel accounting in the power sector is based on existing system of fuel control and registration "Instructions on Fuel Accounting at TPPs. RD 34.09.105.96". According to this document all fuel that is delivered to a power plant must be strictly accounted.
The accounting includes:

- Determination of quantity and quality of the fuel;
- Periodic inventory;
- Claims to the fuel deliverers in case the fuel does not meet the contracted parameters.

To account fuel quantity and define fuel quality thermal power plants should be equipped by special meters, devices and apparatus. The data on fuel delivered and consumed is to be presented in state statistical reports as well as in inter-corporative reports. Primary data on fuel consumption is registered in special register books, in invoices and are used to prepare monthly and annual reports (the so called form No. 15506, form No. 6-TP), both presenting the main performance parameters of a power plant. The latter report includes the aggregated data on the delivered and consumed fuel.
Besides, the annual report 6-TP includes aggregated monthly data, namely, the following:

- installed capacities of a TPPs (electrical and thermal);
- power and heat output;
- fuel used for power and heat production;
- type and quantity of burned fuel.

The quantity and quality of liquid and solid fuels should be controlled (1) before the fuel take-over from the supplier and (2) before fuel burning.
Fuel quality control is conducted by special chemical laboratories of TPPs, which periodically make tests of the fuel got from suppliers and taken from TPPs' stores for burning. Failure in meeting the contracted quality is the cause to claim the suppliers.
The list of the main parameters of fuel consumption is as follows:

Gas:	gas pressure at the measuring device (diaphragm);
	gas temperature before and after diaphragm.
Heavy oil:	weight of oil when emptying the railway tanks;
	oil level in tanks;
	oil temperature in tanks;
	oil density in tanks.

The statistical reports “15506” and “6-TP” can serve as basic documents for GHG emission monitoring provision. The report “15506” is filled in monthly used primary data on daily fuel delivery, its consumption, generation of energy.

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

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

ID number *(Please use numbers to ease cross-referencing to D.2.)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
1. $\boldsymbol{FC_{i,y}}$	Annual quantity of fuels type 'i' consumed in year 'y' in project activity	Fuel flow meter reading at project boundary	mass or volume unit	m	Daily	100%	Electronic/ paper	The total fuels consumption will be monitored both at supplier and project end for cross-verification.
2. $\boldsymbol{NCV_{i,y}}$	Net Calorific Value of fuels type 'i' consumed in year 'y' in project activity	Fuel Supplier, Local Authority, Country specific, IPCC	GJ/m^3	e	Fortnightly	100%	Electronic	The fuels supplier of the power plants in invoices or Regional or national average default values or IPCC default values as provided in Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG inventories

3. ***OXID***	Oxidation Factor of gas and liquid fuels	IPCC	--	e	Annual	100%	Electronic	IPCC default values as provided in Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories
4. $\boldsymbol{EFCO2_{i,,y}}$	Emission factor of fuels type 'i' consumed in year 'y' in project activity	Local/ Regional/ Global (IPCC)	tCO_2/GJ	e	Annual	100%	Electronic	The fuel supplier of the power plants in invoices or Regional or national average default values, IPCC default values as provided in table 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories
5. $\boldsymbol{COEF_{i,y}}$	CO_2 emission Coefficient of fuels type 'i' consumed in year 'y' in project activity	Calculated under project activity	tCO_2/ mass or volume unit	c	Annual	100%	Electronic	
6. $\boldsymbol{PE_y}$	Project emission due to combustion of fuels	Calculated under project activity	tCO_2	c	Annual	100%	Electronic	

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

The project activity is on-site combustion of natural gas to generate electricity and heat. The CO_2 emissions from electricity and heat generation (***PE_y***) are calculated as follows:

$$PE_y = \Sigma FC_{i,y} * COEF_{i,y}$$

Where:

$FC_{i,y}$ = Total quantity of fossil fuel type 'i' consumed in year 'y' (mass or volume unit) in the project plant(CCGT) and Condensing plant

$COEF_{i,y}$ = CO_2 emission coefficient (tCO_2/mass or volume unit) for fossil fuel type 'i' in year 'y' and is obtained:

$$COEF_{i,y} = \Sigma NCV_{i,y} * EFCO2_{i,y} * OXID$$

Where:

$NCV_{i,y}$ = Net calorific value (energy content) of fossil fuel type 'i' in year 'y' (GJ / mass or volume unit)

$EF_{CO2,i,y}$ = CO_2 emission factor of fossil fuel type 'i' in year 'y' (tCO_2/GJ)

$OXID$ = oxidation factor of liquid and gas fuels

For startup fuels, IPCC default calorific values and CO_2 emission factors are acceptable, if local or national estimates are unavailable.

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

ID number *(Please use numbers to ease cross-referencing to D.2.)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	For which baseline method(s) must this element be included	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
7. $EF_{grid,CM,y}$	CO_2 emission	Calculated as a weighted sum of	tCO_2 /MWh	c	Simple OM	Yearly	100%	Electronic	The baseline emission factor is

	factor of the grid	the OM and BM emission factors							calculated as a combined margin, consisting of the combination of operating margin and build margin factors.
8. $EF_{grid,OMsimple,y}$	CO_2 Operating Margin emission factor of the grid	Calculated as indicated in the relevant OM baseline method above	tCO_2 / MWh	c	Simple OM	Yearly	100%	Electronic	The simple OM emission factor is calculated as the generation-weighted average CO2 emissions per unit net electricity generation of all generating power plants serving the system
9. $EF_{grid,BM,y}$	CO_2 Build Margin emission factor of the grid	Calculated as $[\Sigma iF_{i,m,y}*COEF_{i,m}]$ / $[\Sigma m\ GEN_{m,y}]$ over recently built power plants defined in the baseline methodology	tCO_2 / MWh	c	BM	Yearly	100%	Electronic	The build margin emissions factor is the generation-weighted average emission factor of all power units m during the most recent year y for which power generation data is available
10. $FC_{i,m,y}$	Fuel Quantity type 'i' consumed in year 'y'	Obtained from the power producers, dispatch centers or latest local statistics	Mass or volume	m	Simple OM	Yearly	100%	Electronic	Amount of each fossil fuel i consumed by each power source/ plant

11. ***$NCV_{i,y}$***	Net calorific value of fuel type 'i' consumed in year 'y'	Fuel Supplier, Local Authority, Country specific, IPCC	(GJ / mass or volume unit)	e	Simple OM	Yearly	100%	Electronic	The fuel supplier of the power plants in invoices or Regional or national average default values or IPCC default values as provided in Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories
12. ***$EF_{CO2,i,y}$***	CO_2 emission factor of fossil fuel type i in year y	Fuel Supplier, Local Authority, Country specific, IPCC	(tCO_2/GJ)	e	Simple OM	Yearly	100%	Electronic	The fuel supplier of the power plants in invoices or Regional or national average default values IPCC default values as provided in table 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories
13. ***$EG_{m,y}$***	Electricity quantity	Obtained from the power producers, dispatch centers or latest local statistics.	MWh/a	m	Simple OM	Yearly	100%	Electronic	Electricity generation of each power source / plant j, k or n

14. $EF_{EL,m,y}$	CO_2 emission factor	CO_2 emission factor of power unit m in year y	tCO_2/MWh	e	BM	Yearly	100%	Electronic	Calculation of the build margin emissions factor
15.	Plant name	Identification of power source / plant for the OM	Text	e	Simple OM	Yearly	100% of set of plants	Electronic	Identification of plants (j, k, or n) to calculate OM EF
16.	Plant name	Identification of power source / plant for the BM	Text	e	BM	Yearly	100% of set of plants	Electronic	Identification of plants (m) to calculate Build Margin emission factors
17. $GEN_{IMPORTS,,y}$	Electricity quantity	Electricity imports to the project electricity system	kWh	c	Simple OM	Yearly	100%	Electronic	Obtained from the latest local statistics. If local statistics are not available, IEA statistics are used to determine imports.
18. $EF_{IMPORTS,,y}$	Emission factor coefficient	Emission factor is calculated as the generation-weighted average CO_2 emissions per unit net electricity generation of all	tCO_2 /MWh	c	For setting baseline emissions	Yearly	100%	Electronic	CO_2 emission coefficient of electricity imported from connected electricity systems (if

		generating power plants serving in connected electricity systems							imports occur)
19. $EG_{CCProj,y}$	Electricity quantity	Electricity generated in the project plant CC GT	MWh	m	For setting baseline emissions	Yearly	100%	Electronic	The electricity production will be monitored in project activity
20. $EG_{KES\text{-}TP,baseline,y}$	Electricity quantity	The electricity generated in Condensing plant without project activity	MWh	m	For setting baseline emissions	Yearly	100%	Electronic	The electricity production will be monitored without project in original facilities
21. $EG_{KES\text{-}TP,project,y}$	Electricity quantity	The electricity generated in Condensing plant with project activity	MWh	m	For setting baseline emissions	Yearly	100%	Electronic	The electricity production will be monitored in project activity in original facilities
22. ε_{BP}	Energy efficiency	Electricity generated in the absence of the project activity in Condensing plant		e	For setting baseline emissions	Once a year	100%	Electronic	Energy efficiency for electricity generated without project in original facilities will be measured
23. $EFBP_{E,CO2,y}$	CO_2 emission factor	CO_2 emission factor from power unit(in original facilities) TPP in year y	tCO_2/MWh	e	For setting baseline emissions	Yearly	100%	Electronic	Calculation of the baseline emissions from electricity production without project in original facilities

24. ***$EFCO2_{NG,y}$***	CO_2 emission factor	CO_2 emission factor per unit of energy of natural gas in year 'y'	tCO_2/GJ	e	For setting baseline emissions	Yearly	100%	Electronic	Determined by the fuel supplier, wherever possible, otherwise from local or national data and IPCC default values;
25. ***$EFCO2_{HFO,y}$***	CO_2 emission factor	CO_2 emission factor per unit of energy of heavy fuel oil in year 'y'	tCO_2/GJ	e	For setting baseline emissions	Yearly	100%	Electronic	Determined by the fuel supplier, wherever possible, otherwise from local or national data and IPCC default values;
26. ***$BE_{electricity,\ y}$***	Baseline emissions electricity generation displaced due to the project activity in fossil fuel power plants	Calculated under project activity	tCO_2	c	For setting baseline emissions	Annual	100%	Electronic	Calculation of the baseline emissions from electricity generation displaced due to the project activity
27. ***$BE_{elect.\ prod,\ y}$***	Baseline emissions from the electricity production without project in original facilities	Calculated under project activity	tCO_2	c	For setting baseline emissions	Annual	100%	Electronic	Calculation of the baseline emissions from electricity production without project in original facilities in year y

28. BE_y	Total baseline emissions	$BE_{electricity,y}$ + $BE_{elect.\ prod,\ y}$	tCO_2	c	For setting baseline emissions	Annual	100%	Electronic	Calculation of the total baseline emissions

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

1. Replaceable electricity

The baseline emission factor $(EF_{grid,CM,y})$ is calculated as a combined margin **(CM)**, consisting of the combination of operating margin **(OM)** and build margin **(BM)** factors.

Calculation of the operating margin emission factor according to the selected method

Calculation of the Operating Margin emission factors ($EF_{grid,OMsimple,y}$) is based on the Simple OM method as the generation-weighted average emissions per electricity unit (tCO_2/MWh) of all generating sources serving the system, not including low-operating cost and must-run power plants:

$$EF_{grid,OMsimple,y} = \Sigma(FC_{i,m,y} * NCV_{i,y} * EF_{CO2,i,y}) / \Sigma EG_{m,y}$$

Where:

$EF_{grid,OMsimple,y}$ = Simple operating margin CO_2 emission factor in year ‘y’ (tCO_2/MWh)

$FC_{i,m,y}$ = Amount of fossil fuel type ‘i’ consumed by power plant / unit m in year ‘y’ (mass or volume unit)

$NCV_{i,y}$ = Net calorific value (energy content) of fossil fuel type ‘i’ in year ‘y’ (GJ / mass or volume unit)

$EF_{CO2,i,y}$ = CO_2 emission factor of fossil fuel type ‘i’ in year ‘y’ (tCO_2/GJ)

$EG_{m,y}$ = Net electricity generated and delivered to the grid by power plant / unit ‘m’ in year ‘y’ (MWh)

m = All power plants / units serving the grid in year ‘y’ except low-cost / must-run power plants / units

i	=	All fossil fuel types combusted in power plant / unit 'm' in year 'y'
y	=	Either the three most recent years for which data is available at the time of submission of the CDM-PDD to the DOE for validation (ex ante option) or the applicable year during monitoring (ex post option), following the guidance on data vintage in step 2

For the simple OM emissions factor was chosen "ex post option" - the year in which the project activity displaces grid electricity, requiring the emissions factor to be updated annually during monitoring.

As described above, the simple OM emission factors are calculated for **OES North-West** ($EF_{NorthWest,OMsimple,y}$) and **OES Center** ($EF_{Center,OMsimple,y}$).
The baseline simple OM CO_2 ($EF_{grid,OMsimple,y}$) is calculated as the weighted average of the **OES North-West** OM emission factor ($EF_{NorthWest,OMsimple,y}$) and the **OES Center** OM emission factor ($EF_{Center,OMsimple,y}$):

$$EF_{grid,OMsimple,y} = w_{NorthWest,,y} * EF_{NorthWest,OMsimple,y} + w_{Center,y} * EF_{Center,OMsimple,y}$$

where the weights are:

$w_{NorthWest,,y}$ = 79.6%
$w_{Center,y}$ = 20.4%.

Calculation of the build margin emission factor

The build margin emissions factor is the generation-weighted average emission factor (tCO_2/MWh) of all power units 'm' during the most recent year 'y' for which power generation data is available, calculated as follows:

$$EF_{grid,BM,y} = \Sigma(EG_{m,y} * EF_{EL,m,y}) / EG_{m,y}$$

Where:

$EF_{grid,BM,y}$	=	Build margin CO_2 emission factor in year 'y' (tCO_2/MWh)
$EG_{m,y}$	=	Net quantity of electricity generated and delivered to the grid by power unit 'm' in year 'y' (MWh)
$EF_{EL,m,y}$	=	CO_2 emission factor of power unit 'm' in year 'y' (tCO_2/MWh)
m	=	Power (the five power plants that have been built most recently) units included in the build margin
y	=	Most recent historical year for which power generation data is available

For estimating of the Build Margin emission factor $EF_{BM,y}$ the ***Option 2*** has been chosen – the Build Margin emission factor $EF_{BM,y}$ must be updated annually "ex-post" for the year in which actual project generation and associated emissions reductions occur. The sample group ***m*** consists of the five power plants that have been built most recently.

Calculation of the combined margin emission factor

The combined margin emissions factor is calculated as follows:

$$EF_{grid,CM,y} = EF_{grid,OM,y} * w_{OM} + EF_{grid,BM,y} * w_{BM}$$

Where:

$EF_{grid,BM,y}$	=	Build margin CO_2 emission factor in year y (tCO_2/MWh)
$EF_{grid,OM,y}$	=	Operating margin CO_2 emission factor in year y (tCO_2/MWh)
w_{OM}	=	Weighting of operating margin emissions factor (%)
w_{BM}	=	Weighting of build margin emissions factor (%)

The following default values should be used for w_{OM} and w_{BM}:

w_{OM} = 0.5 and w_{BM} = 0.5 for the first crediting period, and w_{OM} = 0.25 and w_{BM} = 0.75 for the second and third crediting period

Baseline emissions from grid electricity generation displaced in fossil fuel power plants due to the project activity are calculated from the electricity quantity generated in the project plant – CCGT ($EG_{CCProj,y}$) and from the electricity quantity generated in the Condensing plant with and without project activity ($EG_{KES\text{-}TP, baseline,y} - EG_{KES\text{-}TP,project,y}$), as follows:

$$BE_{electricity,y} = (EG_{CCProj,y} - (EG_{KES\text{-}TP,baseline,y} - EG_{KES\text{-}TP,project,y})) * EF_{grid,CM,y}$$

2. Electricity generated in the absence of the project activity

Baseline emissions from electricity production are calculated by multiplying the electricity generated in the Condensing plant without project activity ($EG_{KES\text{-}TP, baseline,y}$) with a baseline CO_2 emission factor ($EFBP_{E,CO2,y}$):

$$BE_{elect.\ prod,\ y} = EG_{KES\text{-}TP,\ baseline,y} * EFBP_{E,CO2,y}$$

Where:

$EFBP_{E,CO2,y}$ = CO_2 emission factor (tCO_2/MWh) in certain year for the technology generating electricity in the absence of the project activity and is obtained as:

$$EFBP_{E,CO2,y} = ((0.814*EFCO2_{NG,y} + 0.186*EFCO2_{HFO,y}) / \varepsilon_{BP})*3.6$$

Where:

$EFCO2_{NG,y}$ = CO_2 emission factor per unit of energy of natural gas in year 'y' (tCO_2/GJ)

$EFCO2_{HFO,y}$ = CO_2 emission factor per unit of energy of heavy fuel oil in year 'y' (tCO_2/GJ)

ε_{BP} = the energy production efficiency of the electricity generated technology in the Condensing plant without project

0.814 = share of natural gas on the electricity production in the Condensing plant without project activity

0.186 = share of heavy fuel oil on the electricity production in the Condensing plant without project activity

3. Total baseline emissions (BE_y) is obtained as:

$$BE_y = BE_{electricity,y} + BE_{elect.\ prod,\ y}$$

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

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

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

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

Not applicable

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

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

ID number *(Please use numbers to ease cross-referencing to D.2.)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
29. **FC_y**	Fuel quantity	Amount of Natural gas consumed by project plant	m^3	m	Daily	100%	Electronic/ paper	The total fuel consumption will be monitored both at supplier and project end for cross-verification.
30. **$FC_{BL,y}$**	Fuel quantity	Amount of Natural gas consumed by in the absence of the project activity	m^3	m	Daily	100%	Electronic/ paper	The total fuel consumption will be monitored both at supplier and project end for cross-verification.
31. **NCV_y**	Net Calorific Value of Natural gas	Fuel Supplier, Local Authority, Country specific, IPCC	GJ/m^3	e	Fortnightly	100%	Electronic	Using supplier-provided data, local data, country-specific values, that order of preference. IPCC values

								can be used for startup fuel.
32. **$EF_{NG,upstream,CH4}$**	Emission factor	Fugitive methane emissions from of natural gas from production, transportation, distribution	CH_4 per GJ fuel supplied to final consumers	e	Yearly	100%	Electronic	Reference for emission factor range in Volume 3 of the 1996 Revised IPCC Guidelines
33. **$EF_{BL,upstream,CH4}$**	Emission factor	Fugitive methane emissions occurring in the absence of the project activity	CH_4 per MWh electricity generation	c	Yearly	100%	Electronic	The calculation is consistent with the calculation of CO_2 emissions in the combined margin
34. **GWP_{CH4}**	Global warming potential of CH_4				Valid for the relevant commitment period			IPCC default values
35. **$EG_{PJ,y}$**	Electricity quantity	Electricity generated in the project plant	MWh	m	Yearly	100%	Electronic	The total electricity production will monitored in project
36. **$EF_{j,k}$**	Fuel quantity	Fuel consumption in the plant i included in the build margin	Mass or volume unit	m	Yearly	100%	Electronic	Obtained from the power producers, dispatch centers or latest local statistics.
37.	Fuel quantity	Fuel	Mass or	m	Yearly	100%	Electronic	Obtained from

$EF_{i,k}$		consumption in the plant i included in the operating margin	volume unit					the power producers, dispatch centers or latest local statistics.
38. **$EG_{j,y}$**	Electricity quantity	Electricity generation in the plant j included in the build margin	MWh	m	Yearly	100%	Electronic	Obtained from the power producers, dispatch centers or latest local statistics.
39. **$EG_{i,y}$**	Electricity quantity	Electricity generation in the plant i included in the operating margin	MWh	m	Yearly	100%	Electronic	Obtained from the power producers, dispatch centers or latest local statistics.

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

Leakage emission sources are considered fugitive CH_4 emissions associated with fuel extraction, processing, transportation, and distribution of natural gas used in the project plant, and fossil fuels used in the grid in the absence of the project activity.
Fugitive methane emissions are estimated by multiplying the quantity of natural gas consumed by the project in year y with an emission factor for fugitive CH_4 emissions ($EF_{NG,upstream,CH4}$) from natural gas consumption and subtracting the emissions occurring from fossil fuels used in the absence of the project activity, as follows:

$$LE_{CH4,y} = [(FC_{,y} - FC_{BL,y}) * NCV_y * EF_{NG,upstream,CH4} - EG_{PJ,y} * EF_{BL,upstream,CH4}] * GWP_{CH4}$$

where:

$LE_{CH4,y}$ = Leakage emissions due to fugitive upstream CH_4 emissions in the year 'y' in t CO_2e

$FC_{,y}$ = Quantity of natural gas combusted in the project plant during the year 'y' in m^3

$FC_{BL,y}$	=	Quantity of natural gas combusted in the absence of the project activity during the year 'y' in m³
$NCV_{NG,y}$	=	Average net calorific value of the natural gas combusted during the year 'y' in GJ/m³
$EF_{NG,upstream,CH4}$	=	Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, and distribution in t CH_4 per GJ fuel supplied to final consumers
$EF_{BL,upstream,CH4}$	=	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in t CH_4 per MWh electricity generation in the project plant, as defined below
GWP_{CH4}	=	Global warming potential of methane valid for the relevant commitment period
$EG_{PJ,y}$	=	Electricity generation in the project plant during the year in MWh are calculated from the electricity generated in the project plant – CCGT ($EG_{CCProj,y}$) and from the electricity generated in the Condensing plant with and without project activity ($EG_{KES\text{-}TP,\ baseline,y}$ - $EG_{KES\text{-}TP,project,y}$), as follows:

$$EG_{PJ,y} = EG_{CCProj,y} - (EG_{KES\text{-}TP,\ baseline,y} - EG_{KES\text{-}TP,project,y})$$

The emission factor for upstream fugitive CH_4 emissions occurring in the absence of the project activity ($EF_{BL,upstream,CH4}$) is calculated consistent with the baseline emission factor CO_2 ($EF_{grid,CM,y}$) used in equation (Option 2:Combined Margin), as follows:

$$EF_{BL,upstream,CH4} = 0.5*\Sigma(EF_{j,k} * EF_{k,upstream,CH4}) / \Sigma EG_j + 0.5*\Sigma(EF_{i,k} * EF_{k,upstream,CH4}) / \Sigma EG_i$$

where:

$EF_{NG,upstream,CH4}$	=	Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, and distribution in t CH_4 per GJ fuel supplied to final consumers
j	=	Plants included in the build margin
$FF_{j,k}$	=	Quantity of fuel type 'k' combusted in power plant 'j' included in the build margin
$EF_{k,upstream,CH4}$	=	Emission factor for upstream fugitive methane emissions from production of the fuel type 'k' in t CH_4 per MJ fuel produced
EG_j	=	Electricity generation in the plant 'j' included in the build margin in MWh/a
i	=	Plants included in the operating margin
$FF_{i,k}$	=	Quantity of fuel type 'k' combusted in power plant 'i' included in the operating margin

EG_i = Electricity generation in the plant i included in the operating margin in MWh/a

The calculation is consistent with the calculation of CO_2 emissions in the combined margin, i.e. the same cohort of plants and data on fuel combustion and electricity generation are used, and the values for ***FF*** and ***EG*** are those already determined through the application of " Tool to calculate emission factor for an electricity system".

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

The following equation shall be applied for calculating the emission reductions:

$$ER_y = BE_y - PE_y - LE_y$$

Where:

ER_y = Emissions reductions in year y (t CO_2e)

BE_y = Emissions in the baseline scenario in year y (t CO_2e)

PE_y = Emissions in the project scenario in year y (t CO_2e)

LE_y = Leakage in year y (t CO_2e)

Where total net leakage effects are negative (*LEy* < 0), it should be assumed LEy = 0!

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

D.2. Quality control (QC) and quality assurance (QA) procedures undertaken for data monitored:

Data *(Indicate table and ID number)*	Uncertainty level of data (high/medium/low)	Explain QA/QC procedures planned for these data, or why such procedures are not necessary.

Fuel consumption (1, 10, 29, 30, 36, 37)	Low	Use is made of the measurement methods approved (certified) by the bodies of the State Standard of the Russian Federation. The measurement errors of the devices the readings of which are controlled in monitoring, meet the requirements laid down in the Rules effective in the Russian Federation. Actual sectoral standards on inaccuracy of measurements of: – coal weighing is not more than ±1.75%; – heavy oil volume measurement (which is recalculated further on in weight units) is not more than ± 0.5-0.8%; – direct gas consumption measurements is not more than ± 0.3-1.0%.
Electricity output (13, 17, 19, 20, 21, 35, 38, 39)	Low	The power output is determined via the inductive method by the standardized electricity meters
NCV_y (2,11,31)	Low	No additional QA/QC procedures may need to be planned.
OXID (3)	Low	No additional QA/QC procedures may need to be planned.
Emissions factors (4, 7, 8, 9, 12, 14, 18, 23, 24, 25, 32, 33)	Low	No additional QA/QC procedures may need to be planned.
COEFy (5)	Low	No additional QA/QC procedures may need to be planned.

QA/QC procedures include:

- monitoring of natural gas consumption by the gas meter;
- monitoring of electricity production by the electricity meter;
- monitoring of heat production by meter and other auxiliary devices.

The metering devices are subject to calibration according to manufacturer's manuals.
Monitoring of natural gas quality is performing by gas supplier's laboratory and under control by TPP on the basis of monthly reporting/passports.

All measurement devices using for monitoring data indicated by monitoring plan will be subject to a regular maintenance and testing regime to ensure accuracy according to valid legislation and State Standard of the Russian Federation. JSC "Sixth Wholesale Power Market Generating Company" is responsible for the project implementation, general management and TPP for performance of the plant under the projected mode, "everyday" control and project monitoring during the crediting period. TPP will designate a system manager to be in charge of and accountable for the generation of ERUs including monitoring, record keeping, computation and recording of ERUs, validation and verification. The system manager will officially sign off on all worksheets used for the recording and calculation of ERUs. Defined protocols and routine procedures, with good, professional data entry, extraction and reporting procedures will make it considerably easier for the determinator and verifier to do their work.
The monitoring manual will be compiled and the working staff in the monitoring department will fulfill their responsibilities using this manual.

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

Collection of information required for calculations of reductions of GHG emissions as a result of the project is performed in accordance with the procedure common for the enterprise, as monitoring requires no additional information to be obtained, apart from the data already being collected and processed.

Authority and responsibility of project management, registration, monitoring, measurement and reporting

JSC "Sixth Wholesale Power Market Generating Company":

- organizes monitoring (the appropriate orders and instructions may be issued, specifying the responsible executors, monitoring and reporting are carried out),
- control of monitoring and submission of GHG emissions reporting.

Kirishskaya TPP:

- organizes and conducts personnel training and education,
- recording the required data, monitoring and reporting on the project GHG emissions at the TPP
- operations of power plant equipment,
- recording the required data, monitoring and reporting on the project GHG emissions at the TPP.

Table D.3.1.The internal monitoring of the project implementation and internal audit are presented below:

Organization	**Responsibilities**
JSC "Sixth Wholesale Power Market Generating Company"	• confirmation of annual Monitoring Protocol; • relation with fuel suppliers; • general supervision; • decision making; • internal audits; • appropriate inspections;

Kirishskaya TPP	• analysis of the initial data; • preparation of annual Monitoring Protocol; • reporting on all project parameters; • collection and archiving of data; • primary registering and reporting of the whole scope of project parameters; • archiving of data; • operation of the plant in a projected mode; • calibration of measuring devices.

Procedures identified for training of monitoring personnel

The management of the personnel training and retraining at TPP is carried out by the Technical Director, and the control of implementation thereof – by the Head of the enterprise.

Depending on the category of the personnel, the following methods are applied:

- checking the knowledge of the rules, norms and instructions on technical operation, labor protection, industrial and fire safety;
- on-going training and retraining.

The activity with the personnel is organized and carried out in accordance with the plans approved by the Technical Director of the enterprise that include the following:

- entry training;
- personnel training in second and allied professions;
- retraining;
- organizing the activity of the technical libraries, technical materials rooms and simulator training facilities.

Procedures identified for emergency preparedness for cases where emergencies can cause unintended emission

To prevent emergency at all main components of energy equipment the protection system is envisaged.

The single situation where unintended emission can arise is an emergency at the gas distribution station and gas pipelines. Leakages of natural gas in the gas supply system cannot be allowed according to operation condition. In this situation immediate cutting-off of natural gas delivery and elimination of defects are carried out.

Period between moment of appearance of emergency conditions and moment of cutting-off of natural gas delivery is a short time interval. In case of gas pipeline damage GHG emissions will not be great as gas delivery at the damaged section will be stopped in minimum time. During the period of carrying out of repair works (fixed time limit – up to 1-3 days) the power plant has to be fired reserved fuel (heavy oil) and this is led to increasing of GHG emissions. The volume of GHG emissions under reserved fuel firing is equal less than 1 % of annual GHG project emissions as only three-day reserve of heavy oil is envisaged at the plant.

Procedures identified for calibration of monitoring equipment

Company's authorized department provides the operation of measuring equipment and carries out control of correctness of its reading. The control equipment and devices are checked up periodically in accordance with calibration schedule. Calibration is carried out at stands with using of standard devices. There is also reserve base of control equipment at the plant which can be used in case of failure of any measuring equipment.

Procedures identified for maintenance of monitoring equipment and installations

Management of maintenance at the plant is carried out by manufacturers of the equipment based on contract terms of after-sale services of the delivered main equipment (gas turbine unit) in operation and by specialized companies for maintenance of auxiliary equipment as well as buildings.
Duration and periodicity of inspections and repairs of gas turbine unit corresponds to recommended periodicity of inspections and maintenance of GTE.

Maintenance and current repairs of electric equipment and facilities of automated control system of technological process will be carried out by personnel of Kirishskaya TPP.

Fulfillment of capital and mid-life repairs of main equipment are envisaged with the assistance of firms and manufacturers of the equipment based on contract terms especially gas turbine unit as well as with attracting of additional personnel of other specialized companies for maintenance of auxiliary equipment and buildings.

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

The entities setting the monitoring are as follows:

- **JSC "Sixth Wholesale Power Market Generating Company"**

General Director – Mr. Valentin M. Sanko

Postal address:

JSC "OGK-6"
21, Mytnaya street, Moscow, 115162, Russia.
Phone: +7(495) 380-0410
e-mail: office@ogk6.ru

- **ECF Project Ltd**

General Director – Mr. Oleg A. Korkhov
Address: 18, Bolshaya Kommunisticheskaya, 109004, Moscow, Russia
Tel. +7 495 785 80 46
Email: ecf@energyfund.ru

- **PROFING s.r.o.**

Managing Partner - Ivan Mojik
Address: Mliekarenska 10, 824 92 Bratislava, Slovakia
Telephone: +421 2 5363 4861
E-mail: mojik@profing.eu

SECTION E. Estimation of greenhouse gas emission reductions

E.1. Estimated project emissions:

The project activity is on-site combustion of natural gas (and heavy fuel oil as reserve fuel) to generate electricity. The CO_2 emissions from electricity generation are calculated in accordance with AM0029. The oxidation factors ($OXID_f$) of natural gas and of heavy fuel oil both equal 0.995.

Table E.1.1. Initial information for calculation GHG project emissions

Parameters	Years					
	Unit	**2008**	**2009**	**2010**	**2011**	**2012**
Annual power output	thous. MWh	6 104	6 091	5 621	7 857	7 831
Specific NG consumption for electricity supplied	m^3/MWh	247.24	247.24	247.24	218.22	218.12
Specific HFO consumption for electricity supplied	kg/MWh	47.73	47.73	47.73	22.14	22.06
Annual NG consumption	thous. m^3	1 509 180	1 505 848	1 389 631	1 714 514	1 708 034
Annual HFO consumption	t	291 347	290 703	268 268	173 966	172 715
NG net calorific value	MJ/Nm^3	33.62	33.62	33.62	33.62	33.62
HFO net calorific value	MJ/kg	39.77	39.77	39.77	39.77	39.77
Coefficient of CO_2 emission NG burning	t CO_2/TJ	56.1	56.1	56.1	56.1	56.1
Coefficient of CO_2 emission HFO burning	t CO_2/TJ	77.3	77.3	77.3	77.3	77.3

Table E.1.2. Direct GHG project emissions

Parameters	Years					
	Unit	**2008**	**2009**	**2010**	**2011**	**2012**
CO_2 emissions from NG combustion	tCO_2	2 832 206	2 825 952	2 607 853	3 217 545	3 205 385
CO_2 emissions from HFO combustion	tCO_2	891 289	889 321	820 685	532 198	528 371
Emission factor for electricity production	gCO_2/kWh	610.0	610.0	610.0	477.3	476.8
Total direct CO_2 emissions	**t CO_2**	**3 723 494**	**3 715 272**	**3 428 538**	**3 749 743**	**3 733 756**

The estimated GHG emission by sources will be 18 350 804 tonnes of CO_2e.

E.2. Estimated leakage:

Leakage emissions are calculated in accordance with AM0029.

Parameters	Years					
	Unit	**2008**	**2009**	**2010**	**2011**	**2012**
TPP*) annual natural gas consumption – baseline	thous. m^3	1 509 180	1 505 848	1 389 631	1 081 378	1 073 463
TPP*) annual natural gas consumption – project	thous. m^3	1 509 180	1 505 848	1 389 631	1 714 514	1 708 034
Natural gas net calorific value	MJ/Nm^3	33.620	33.620	33.620	33.620	33.620
Coefficient of CH_4 emission natural gas burning	t CH_4/TJ	0.921	0.921	0.921	0.921	0.921
Replaceable electricity	thous. MWh	0	0	0	3 483 043	3 488 846
Combined coefficient of CH_4 replaceable electricity	tCH_4/MWh	0.00697	0.00697	0.00697	0.00697	0.00697
CH_4 leakages – baseline	t CH_4	46 730	46 627	43 029	57 767	57 563
CH_4 leakages – project	t CH_4	46 730	46 627	43 029	53 088	52 888
Total CH_4 leakages (project minus **baseline)**	**t CH_4**	**0**	**0**	**0**	**-4 679**	**-4 675**
Total CO_2e leakages (project minus **baseline)**	**t CO_2e**	**0**	**0**	**0**	**-98 262**	**-98 178**

*) Condensing plant

Estimated leakage emissions will be -196 440 tonnes of CO_2e.

Where total net leakage effects are negative ($LE_y < 0$), then $LE_y = 0$ should be assumed. As this is the case, leakages are assumed having value zero.

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

Parameters	Years					
	Unit	**2008**	**2009**	**2010**	**2011**	**2012**
CO_2 emissions project	t CO_2e	3 723 494	3 715 272	3 428 538	3 749 743	3 733 756
CO_2 leakages (project-baseline)	t CO_2e	0	0	0	0	0
Total CO_2 emissions (project + leakages)	**t CO_2e**	**3 723 494**	**3 715 272**	**3 428 538**	**3 749 743**	**3 733 756**

The estimated GHG emissions due to the project activity will be 18 350 804 tCO_2e comprising GHG emissions from E.1. GHG emissions by sources and E.2. leakage emissions.

E.4. Estimated baseline emissions:

Baseline emissions are calculated in accordance with AM0029 by multiplying the electricity generated in the project plant ($EG_{PJ,y}$) with a baseline CO_2 emission factor ($EF_{BL,CO2,y}$). The oxidation factors ($OXID_f$) of natural gas and of heavy fuel oil both equal 0.995.

Table E.4.1. Initial information for calculation GHG baseline emissions

Parameters	Years					
	Unit	**2008**	**2009**	**2010**	**2011**	**2012**
Annual power output	thous. MWh	6 104	6 091	5 621	4 374	4 342
Specific NG consumption for electricity supplied	m^3/MWh	247.24	247.24	247.24	247.24	247.24
Specific HFO consumption for electricity supplied	kg/MWh	47.73	47.73	47.73	47.73	47.73
Annual NG consumption	thous. m^3	1 509 180	1 505 848	1 389 631	1 081 378	1 073 463
Annual HFO consumption	t	291 347	290 703	268 268	208 760	207 232
NG net calorific value	MJ/Nm^3	33.62	33.62	33.62	33.62	33.62
HFO net calorific value	MJ/kg	39.77	39.77	39.77	39.77	39.77
Coefficient of CO_2 emission NG burning	t CO_2/TJ	56.1	56.1	56.1	56.1	56.1
Coefficient of CO_2 emission HFO burning	t CO_2/TJ	77.3	77.3	77.3	77.3	77.3
Replaceable electricity	thous. MWh	0	0	0	3 483	3 489
Combined coefficient of CO_2 replaceable electricity	tCO_2/MWh	0.5199	0.5199	0.5199	0.5199	0.5199

Table E.4.2 Results of the calculations of GHG baseline emissions

Parameters	Years					
	Unit	**2008**	**2009**	**2010**	**2011**	**2012**
Total GHG baseline emissions	**tCO_2**	**3 723 494**	**3 715 272**	**3 428 538**	**4 478 868**	**4 462 358**
GHG project emissions associated with replaceable electricity	tCO_2	0	0	0	1 810 860	1 813 877
GHG project emissions associated with electricity production	tCO_2	3 723 494	3 715 272	3 428 538	2 668 007	2 648 480
EF - replaceable electricity	**gCO_2/kWh**	**0.0**	**0.0**	**0.0**	**519.9**	**519.9**
EF - electricity production	**gCO_2/kWh**	**610.0**	**610.0**	**610.0**	**610.0**	**610.0**
EF mix - replaceable and production electricity	**gCO_2/kWh**	**610.0**	**610.0**	**610.0**	**570.1**	**569.9**

The estimated baseline emissions GHG will be 19 808 530 tCO_2e.

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

The estimated emissions reduction (2010-2012) will be **1 457 726** tCO_2e.

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

Year	**2008**	**2009**	**2010**	**2011**	**2012**	**Total**
Baseline GHG emission (tCO_2e)	3 723 494	3 715 272	3 428 538	4 478 868	4 462 358	**19 808 530**
Project + leakages GHG emission (tCO_2e)	3 723 494	3 715 272	3 428 538	3 749 743	3 733 756	**18 350 804**
Emission reduction (tCO_2e)	**0**	**0**	**0**	**729 124**	**728 601**	**1 457 726**

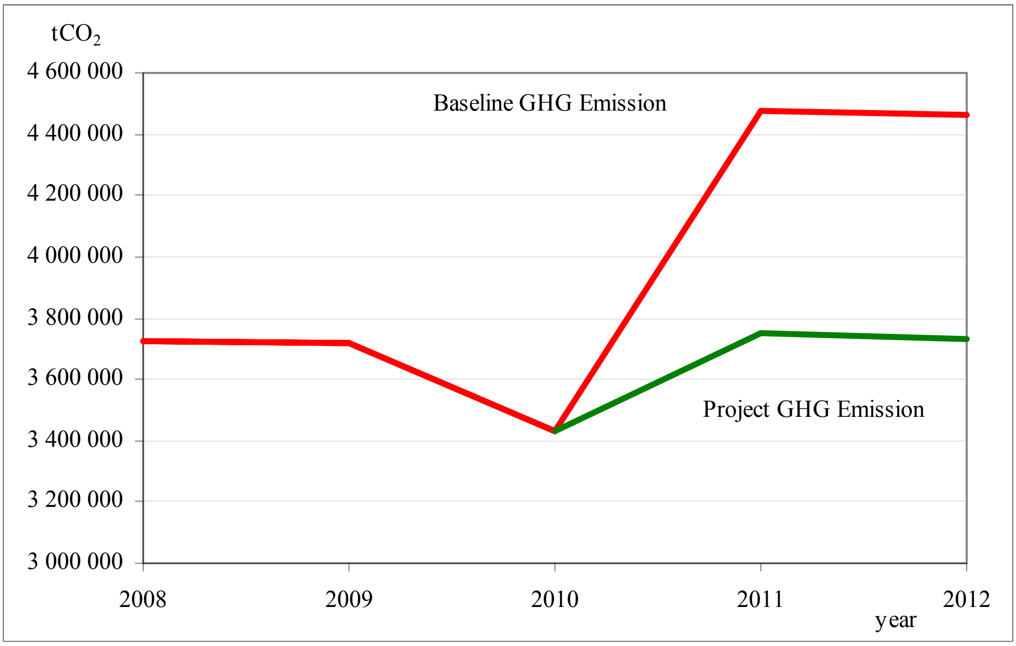


Figure E.6.1. GHG emissions in baseline and under the project implementation

SECTION F. Environmental impacts

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

The ecological effect gained from the project implementation (reduction of NO_X and SO_2) is reached by increasing of fuel combustion efficiency due to installation of highly efficient equipment – gas turbines.

On site emissions:

On site NO_X and SO_2 emissions calculation was based on emissions for electricity production in baseline scenario and project scenario:

Table F.1.1 NOx emissions in baseline and project scenarios

		2008	2009	2010	2011	2012
Baseline emissions						
NO_X –electricity production	tNO_X	4 240	4 230	3 904	3 502	3 476
Project emissions						
NO_X –electricity production	tNO_X	4 240	4 230	3 904	4 146	4 125
Baseline *minus* project	tNO_X	0	0	0	-644	-648

After project implementation, NO_X emissions from Kirishskaya TPP will **increase** by 646 t (annual average 2011-2012), against baseline scenario.

Table F.1.2 SO_2 emissions in baseline and project scenarios

		2008	2009	2010	2011	2012
Baseline emissions						
SO_2 –electricity production	t SO_2	16 024	15 989	14 755	11 482	11 398
Project emissions						
SO_2 –electricity production	t SO_2	16 024	15 989	14 755	11 308	11 226
Baseline *minus* project	t SO_2	0	0	0	174	171

After project implementation, SO_2 emissions from Kirishskaya TPP will **decrease** by 172.5 t (annual average 2011-2012), against baseline scenario.

However, dispersion study shows that concentration of pollutants in ambient air will not exceed 0.1 PDK (applied limit value) in none of points where concentration of pollutants was calculated. In addition, also when taking into account background concentration, hygienic standards will not be exceeded.

Regional emissions:

The same methodology as for estimation of emission factor EFCO2 was applied for calculation of emission factors for NO_X and SO_2 within power plants OES North-West and OES Center. Thus, overall NO_X and SO_2 emissions for considered set of plants operating within CES of North-West and Center have been calculated.

Following concentrations were assumed:

Table F.1.3. The concentrations of NO_X and SO_2

Fuel	NO_X (NO_2) stack concentration*) [mg/m³]	Sulfur content in fuel [%]
Solid (coal)	650	1.0
Liquid	450	2.75
Gaseous (NG)	350	0.0
Gas turbines	50	

*) Emission limit values from "UN ECE Protocol To The 1979 Convention On Long-Range Transboundary Air Pollution To Abate Acidification, Eutrophication And Ground-Level Ozone" applicable for existing installations

Table F.1.4. Regional NO_X emissions in baseline and project scenarios

Parameters	Years					
	Unit	2008	2009	2010	2011	2012
Baseline scenario						
Combined coefficient of NOx replaceable electricity	tNO_X/MWh	0.00071	0.00071	0.00071	0.00071	0.00071
Replaceable electricity	thous. MWh	0	0	0	3 483	3 489
NOx- replaceable electricity		0	0	0	2 473	2 478
NOx- electricity production	tNO_X	4 240	4 230	3 904	3 502	3 476
Total NOx emissions	tNO_X	4 240	4 230	3 904	5 975	5 954
Project scenario						
Coefficient of NOx electricity	tNO_X/MWh	0.0007	0.0007	0.0007	0.0005	0.0005
Annual power output	thous. MWh	6 104	6 091	5 621	7 857	7 831
NOx emissions electricity production	tNO_X	4 240	4 230	3 904	4 146	4 125
Total NOx emissions	tNO_X	4 240	4 230	3 904	4 146	4 125
Baseline *minus* project	tNO_X	0	0	0	1 830	1 829

In regional scope, NO_X emission from power plants within CES of Center will **decrease** by 1 830 t (annual average 2011-2012) against baseline scenario.

Change in sulphur dioxide emissions will occur due to replacement of electricity from grid by electricity generated in highly efficient gas turbines.

Table F.1.5. SO_2 emissions in baseline and project scenarios

Parameters		Years				
	Unit	2008	2009	2010	2011	2012
Baseline scenario						
Combined coefficient of SO_2 for replaceable electricity	tSO_2/MWh	0.0012	0.0012	0.0012	0.0012	0.0012
Replaceable electricity	thous. MWh	0	0	0	3 483	3 489
SO_2 – replaceable electricity	tSO_2	0	0	0	4 237	4 244
SO_2 – electricity production	tSO_2	16 024	15 989	14 755	11 482	11 398
Baseline – total emissions	tSO_2	16 024	15 989	14 755	15 719	15 642
Project scenario						
SO_2 – electricity production	tSO_2	16 024	15 989	14 755	11 308	11 226
Baseline *minus* project	tSO_2	0	0	0	4 411	4 415

In regional scope, SO_2 emission from power plants within CES of Center will **decrease** by 4 412.5 t (annual average 2011-2012) against baseline scenario.

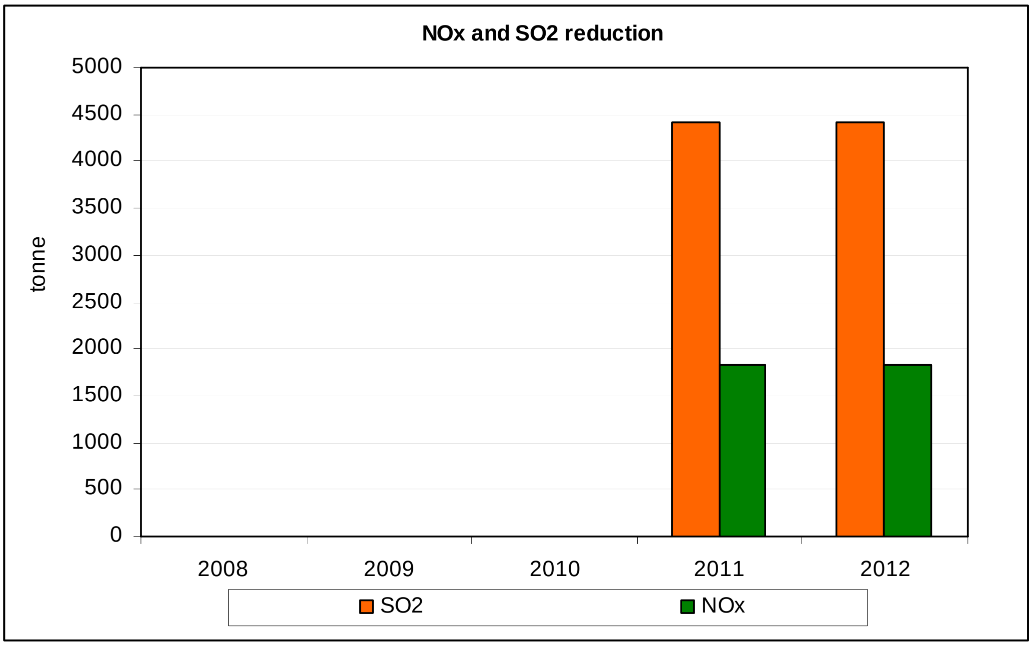


Figure F.1.1. SO_2 and NO_x emission reduction of the project

Transboundary transfer

The Russian Federation (emissions from the European Territory of Russia only) is party to two protocols to the UN Convention on Long-range Transboundary Air Pollution: *"The UN ECE 1985 Helsinki Protocol on the Reduction of Sulphur Emissions or their Transboundary Fluxes by at least 30 per cent"* and *"The UN ECE 1988 Sofia Protocol concerning the Control of Emissions of Nitrogen Oxides or their Transboundary Fluxes".*

The UN ECE 1985 Helsinki Protocol on the Reduction of Sulphur Emissions or their Transboundary Fluxes by at least 30 per cent

The Parties shall reduce their national annual sulphur emissions or their transboundary fluxes by at least 30 per cent as soon as possible and at the latest by 1993, using 1980 levels as the basis for calculation of reductions. The obligation of the Russian Federation refers to the European Territory of Russia only (within the EMEP area). The SO_2 emissions decreased from 7 323 kt in 1980 to 3 637 kt in 1990 (by 50.3%) and continued in decrease to 1 847 kt in 2005 (by 74.8%).
The regional decrease of 4 413 t SO_2 annually caused by the project will contribute to the downwards trend. The decrease by the project represents 1.17% change in SO_2 emissions originating from OES North-West and OES Centre large combustion sources (376 654 t; 2006).

The UN ECE 1988 Sofia Protocol concerning the Control of Emissions of Nitrogen Oxides or their Transboundary Fluxes

The Parties shall, as soon as possible and as a first step, take effective measures to control and/or reduce their national annual emissions of nitrogen oxides or their transboundary fluxes so that these, at the latest by 31 December 1994, do not exceed their national annual emissions of nitrogen oxides or transboundary fluxes of such emissions for the calendar year 1987. The obligation of the Russian Federation refers to the European Territory of Russia only (within the EMEP area). However, the NO_X emissions decreased from 3 411 kt in 1987 to 2 570 kt in 1995 (by 24.7%) increasing slightly to 2 795 kt in 2005 (still 18.1% below 1987 level).
The regional decrease of 1 830 t NO_X annually caused by the project will contribute to the downwards trend. The decrease by the project represents 1.02% change in NO_X emissions originating from OES North-West and OES Centre large combustion sources (179 930 t; 2006).

Conclusions:
Kirishskaya TPP is considered to be a source of emissions under the UN Convention on Long-range Transboundary Air Pollution and its two protocols. Implementation of the project will contribute to compliance of the Russian Federation with its commitments by decreasing NO_X and SO_2 emissions.

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

Locally, the project brings slight increase in NO_X emissions together with slight decrease of SO_2 emissions, however, in regional scope, due to project implementation emissions of NO_X and SO_2 will slightly decrease.
In general, environmental impacts should be considered as negligible.

SECTION G. Stakeholders' comments

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

The stakeholders identified for the project "Reconstruction of Kirishskaya TPP with installation of 750 MW Combined-Cycle Unit" are the local population, which is represented by town Kirishi and Leningrad Region as well as elected representatives and municipal bodies.

Under the Russian legislation (Federal Law No. 7 dated 10.01.2002 "On Environmental Protection" and Federal Law No. 174 dated 23.11.1995 "On Environmental Impact Assessment") the project was submitted for the environmental impact estimation to the Federal Service for Ecological, Technological and Atomic Supervision (RosTekhNadzor) and Ministry of Natural Resources, Federal Service for Supervision of Natural Resources (RosPrirodNadzor). Therefore, the official Orders from Regional Office of the Ecological and Technological Supervision of RosTekhNadzor and Regional Office of the Federal Nature Management Supervision Service of RosPrirodNadzor will be submitted as stakeholders' comments to the determinator during on-site visit.

Annex 1

CONTACT INFORMATION ON PROJECT PARTICIPANTS

Organisation:	Open JSC "Sixth Generation Company of the Wholesale Electricity Market" (JSC "OGK-6") Branch "Kirishskaya TPP"
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Represented by:	
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Annex 2

BASELINE INFORMATION

In the baseline methodology the build margin (BM) and operating margin (OM) approach is used as specified in "Tool for the demonstration and assessment of additionality" and calculation of GHG emissions was based on the baseline methodology AM0029 "Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas".

The project site and all power plants connected physically to the electricity system that the Kirishskaya TPP is connected to and that can be dispatched without significant transmission constraints is represented by set of power plants grouped in OES North-West. Thus, for the purpose of determining the electricity emission factor, OES North-West represents the relevant electric power system.

Therefore, calculation of operating margin emission factors was based on analysis of structure of set of power plants grouped in OES North-West. For this purpose number of 30 fossil fuel power plants within OES North-West was selected out of regional generating companies from Arkhangelskoe RDU, Karelskoe RDU, Kolskoe RDU, Komi RDU, Leningradskoe RDU, Novgorodskoe RDU, Vologodskaya oblast and Pskovskaya oblast. Low-cost power plants preferably connected to grid (renewable energy sources) were not included in selection.

Total capacity of sources within OES North-West is 12 266.6 MW. Installed capacity of selected fossil fuel power plants is 10 766 MW (51.5%), capacity of nuclear, hydro and biomass power plants is 8 618.3 MW (41.3%). Remaining capacity belongs to industrial power plants with capacity 1 500.9 MW (7.2%).

As OES North-West imports power from OES Center, after project implementation import will drop; thereby certain amount of electricity produced in OES Centre is replaced by Kirishskaya TPP production.

Total capacity of sources within OES Center is 49 312 MW. Installed capacity of selected fossil fuel power plants is 32 499 MW (66%), capacity of nuclear, hydro and biomass power plants is 14 099 MW (28%). Remaining capacity belongs to industrial power plants with capacity 2 715 MW (5.5%). There is surplus installed capacity in OES Center 1 423.1 MW.

After implementation of the project, Kirishskaya TPP will supply to the grid 9 173 thous. MWh of electricity annualy. From this amount, enhanced production of electricity (3 483 thous. MWh) will replace part of electricity generated in OES North-West (2 771 thous. MWh) and part of electricity generated in OES Center (712 thous. MWh) by fossil fuel power plants. These figures also represent replaced electricity split between above-mentioned OESs. Simple operating margin CO_2 emission factor will therefore consist of respective simple operating margin CO_2 emission factors for OES North-West (weight 0.796 or 79.6%) and OES Center (weight 0.204 or 20.4%).

Calculation of Operating Margin emission factors (*EFOM,simple,y*) was based on analysis of structure of set of power plants grouped in OES Center. For this purpose number of 77 fossil fuel power plants within OES Center was selected out of regional generating companies from regions Belgorod, Bryansk, Orel, Ryazan, Smolensk, Tambov, Tula, Voronezh, Kaluga, Kursk, Lipetsk, Nizhgorodsk, Vladimirsk, Moscow, Ivanovsk, Yaroslavsk, Tversk, Kostromsk, Vologodsk. Low-cost power plants preferably connected to grid (renewable energy sources) were not included in selection.
Average EF_{OM} for year 2006 were calculated according to Simple OM methodology using amount of produced electricity, fuel consumed, heating values and CO_2 emission factors at each single power plant (77 plants).

Table Annex.2.1. Operating Margin emission factors (structure of power plants grouped in OES North-West)

Structure of OES North-West 2006						
No.	**Installation**	**Company**	**RDU**	**Electricity**	**Emission**	**EF CO_2**
				GWh	tCO_2	tCO_2/MWh
1	Arkhangelskaya TEC	OAO "TGK-2"	Arkhangelskoe RDU	1 460	978 759	0.6702
2	Severodvinskaya TEC-1	OAO "TGK-2"	Arkhangelskoe RDU	1 028	1 049 914	1.0210
3	Severodvinskaya TEC-2	OAO "TGK-2"	Arkhangelskoe RDU	485	342 416	0.7066
4	Mezenskaya DES (Archenergo RSK)	MRSK Mezenskaya DES	Arkhangelskoe RDU	14	6 721	0.4934
5	Petrozavodskay TEC	OAO "TGK-1"	Karelskoe RDU	804	353 787	0.4402
6	Apatitskaya TEC	OAO "TGK-1"	Kolskoe RDU	369	332 460	0.9018
7	Murmanskaya TEC	OAO "TGK-1"	Kolskoe RDU	17	20 058	1.2125
8	Vorkutskaya TEC-1	OAO "TGK-9"	Komi RDU	96	131 449	1.3624
9	Vorkutskaya TEC-2	OAO "TGK-9"	Komi RDU	1 039	1 238 444	1.1918
10	Intinskaya TEC	OAO "TGK-9"	Komi RDU	44	50 469	1.1344
11	Petchorskaya GRES	OAO "OGK-3"	Komi RDU	3 274	1 772 543	0.5414
12	Sosnogorskaya TEC	OAO "TGK-9"	Komi RDU	1 445	928 861	0.6426
13	Kirishinskaya GRES	OAO "OGK-6"	Leningradskoe RDU	6 911	4 215 689	0.6100
14	Severo-Zapadnaya TEC	OAO Severo-Zapadnaya	Leningradskoe RDU	3 324	1 357 406	0.4084
15	Avtovskaya TEC-15	OAO "TGK-1"	Leningradskoe RDU	1 177	675 448	0.5739
16	Vasileostrovskaya TEC-7	OAO "TGK-1"	Leningradskoe RDU	553	286 580	0.5178
17	Vyborskaya TEC-17	OAO "TGK-1"	Leningradskoe RDU	1 047	563 844	0.5386
18	Dubrovskaya TEC-8	OAO "TGK-1"	Leningradskoe RDU	245	186 350	0.7607
19	Pervomaskaya TEC-14	OAO "TGK-1"	Leningradskoe RDU	759	463 368	0.6108
20	Pravoberezhnaya TEC-5	OAO "TGK-1"	Leningradskoe RDU	339	186 800	0.5515
21	Severnaya TEC-21	OAO "TGK-1"	Leningradskoe RDU	2 000	982 927	0.4914
22	CTEC-2 (g.S-Peterburg)	OAO "TGK-1"	Leningradskoe RDU	347	227 170	0.6540
23	CTEC-3 (g.S-Peterburg)	OAO "TGK-1"	Leningradskoe RDU	15	12 835	0.8671
24	Yuzhnaya TEC-22	OAO "TGK-1"	Leningradskoe RDU	2 616	1 236 780	0.4728
25	DES na o.Valaam(Petrozavodskoj TEC)	OAO "TGK-1"	Karelskoe RDU	3	2 227	0.8380
26	Novgorodskaya GRES	OAO "OGK-2"	Novgorodskoe RDU	685	424 166	0.6191
27	Tcherepoveckaya GRES	OAO "OGK-6"	Vologodskaya oblast	3 027	2 654 634	0.8771
28	Vologodskaya TEC	OAO "TGK-2"	Vologodskaya oblast	81	56 335	0.6994
29	Pskovskaya GRES	OAO "OGK-2"	Vologodskaya oblast	1 776	960 834	0.5409

30	KOMIENERGO	KOMIENERGO	KOMIENERGO	16	19 378	1.1825
Total				**34 267**	**21 273 983**	**0.6208**

Table Annex.2.2. Operating Margin emission factors (structure of power plants grouped in OES Center)

Structure of OES Center 2006							
No.	**RDU**	**Company**	**Installation**	**Region**	**Electricity**	**Emission**	**EF CO_2**
					GWh	tCO_2	tCO_2/MWh
1	Belgorod RDU	TGC-4	Belgorod CHPP	Belgorodskaya Oblast	88	55 024	0.6255
2	Belgorod RDU	TGC-4	Gubinskaya CHPP	Belgorodskaya Oblast	83	54 130	0.6494
3	Belgorod RDU	TGC-4	GTU CHPP Luch	Belgorodskaya Oblast	318	120 657	0.3790
4	Belgorod RDU	TGC-4	Shebekinskaya	Belgorodskaya Oblast	0	0	0
5	Voronezh RDU	TGC-4	Voronezhskaya	Voronezhskaya Oblast	145	522 247	0.6900
6	Voronezh RDU	TGC-4	Voronezhskaya	Voronezhskaya Oblast	6	4 112	0.6967
7	Kursk RDU	TGC-4	Kurskaya CHPP-1	Kurskaya Oblast	781	440 775	0.5643
8	Kursk RDU	TGC-4	Kurskaya CHPP-4	Kurskaya Oblast	11	7 035	0.6190
9	Lipeckoe RDU	TGC-4	Dankovskaya CHPP	Lipeckaya Oblast	33	25 923	0.7918
10	Lipeckoe RDU	TGC-4	Eleckaya CHPP	Lipeckaya Oblast	45	35 071	0.7758
11	Lipeckoe RDU	TGC-4	Lipeckaya CHPP-2	Lipeckaya Oblast	1 552	813 617	0.5242
12	Orlovskoe RDU	TGC-4	Orlovskaya CHPP	Orlovskaya Oblast	1 201	602 108	0.5014
13	Orlovskoe RDU	TGC-4	Livenskaya CHPP	Orlovskaya Oblast	40	27 564	0.6926
14	Ryazanskoe RDU	OGK-6	TPP-24 (Moscow)	Ryazanskaya Oblast	1 675	886 028	0.5290
15	Ryazanskoe RDU	OGK-6	Ryazanskaya TPP	Ryazanskaya Oblast	7 367	5 401 833	0.7333
16	Ryazanskoe RDU	TGK-4	Dyagilevskaya CHPP	Ryazanskaya Oblast	417	219 575	0.5271
17	Smolenskoe RDU	OGK-4	Smolenskaya TPP	Smolenskaya Oblast	2 213	1 629 043	0.7360
18	Smolenskoe RDU	TGC-4	Smolenskaya CHPP-	Smolenskaya Oblast	1 454	702 971	0.4836
19	Smolenskoe RDU	TGC-4	Dorogobuzhskaya	Smolenskaya Oblast	168	116 170	0.6901
20	Smolenskoe RDU	TGC-4	Bryanskaya TPP	Bryanskaya Oblast	67	59 203	0.8847
21	Smolenskoe RDU	TGC-4	Klincovskaya CHPP	Bryanskaya Oblast	33	22 695	0.6925
22	Smolenskoe RDU	TGC-4	Kaluzhskaya CHPP-1	Kaluzhskaya Oblast	27	28 848	1.0709
23	Tambovskoe RDU	TGC-4	Kotovskaya CHPP	Tambovskaya Oblast	180	121 428	0.6758
24	Tambovskoe	TGC-4	Tambovskaya CHPP	Tambovskaya Oblast	926	540 522	0.5839

25	Tulskoe	OGK-3	Tcherepetskaya TPP	Tulskaya Oblast	3 099	3 446 254	1.1119
26	Tulskoe	TGC-4	Aleksinskaya CHPP	Tulskaya Oblast	214	165 313	0.7710
27	Tulskoe	TGC-4	Eferemovskaya	Tulskaya Oblast	280	180 066	0.6420
28	Tulskoe	TGC-4	Novomoskovskaya	Tulskaya Oblast	423	295 912	0.6995
29	Tulskoe	TGC-4	Pervomayskaya	Tulskaya Oblast	393	246 141	0.6264
30	Tulskoe	TGC-4	Shchekinskaya TPP	Tulskaya Oblast	1 838	1 084 235	0.5898
31	Nizhegorodskoe	TGC-6	Dzerzhinskaya CHPP	Nizhegorodskaya	2 447	1 380 147	0.5640
32	Nizhegorodskoe	TGC-6	Nizhegorodskaya	Nizhegorodskaya	629	350 410	0.5574
33	Nizhegorodskoe	TGC-6	Igumnovskaya CHPP	Nizhegorodskaya	148	187 107	1.2654
34	Nizhegorodskoe	TGC-6	Nobogorkovskaya	Nizhegorodskaya	821	521 854	0.6359
35	Nizhegorodskoe	TGC-6	Sormovskaya CHPP	Nizhegorodskaya	1 181	732 310	0.6199
36	Vladimirskoe	TGC-6	Vladimirskaya CHPP	Vladimirskaya Oblast	1 923	984 003	0.5116
37	Vladimirskoe	TGC-6	CHPP Vladimirskikh	Vladimirskaya Oblast	0	0	0
38	Moskovskoe	OGK-1	Kashirskaya TPP-4	Moskovskaya Oblast	6 275	4 502 924	0.7176
39	Moskovskoe	OGK-4	Shaturskaya TPP-5	Moskovskaya Oblast	4 412	3 080 975	0.6983
40	Moskovskoe	TGC-3	HPP-1 m.Smidovicha	Moscow	294	75 892	0.2581
41	Moskovskoe	TGC-3	TPP-3 im.Klassona	Moskovskaya Oblast	151	90 792	0.6010
42	Moskovskoe	TGC-3	CHPP-6 [Moscow]	Moskovskaya Oblast	28	14 892	0.5345
43	Moskovskoe	TGC-3	CHPP-7 branch	Moscow	0	0	0
44	Moskovskoe	TGC-3	CHPP-8 [Moscow]	Moscow	2 886	1 509 211	0.5230
45	Moskovskoe	TGC-3	CHPP-9 [Moscow]	Moscow	1 230	561 353	0.4562
46	Moskovskoe	TGC-3	CHPP-11	Moscow	1 918	853 225	0.4449
47	Moskovskoe	TGC-3	CHPP-12 [Moscow]	Moscow	2 397	1 014 462	0.4231
48	Moskovskoe	TGC-3	CHPP-16 [Moscow]	Moscow	2 175	936 906	0.4309
49	Moskovskoe	TGC-3	CHPP-17 [Moscow]	Moskovskaya Oblast	543	394 197	0.7262
50	Moskovskoe	TGC-3	CHPP-20 [Moscow]	Moscow	4 104	1 882 929	0.4588
51	Moskovskoe	TGC-3	CHPP-21 [Moscow]	Moscow	8 348	2 995 958	0.3589
52	Moskovskoe	TGC-3	CHPP-22 [Moscow]	Moskovskaya Oblast	8 486	4 032 963	0.4753

53	Moskovskoe	TGC-3	CHPP-23 [Moscow]	Moscow	8 648	3 451 676	0.3991
54	Moskovskoe	TGC-3	CHPP-25 [Moscow]	Moscow	8 315	3 564 278	0.4287
55	Moskovskoe	TGC-3	CHPP-26 [Moscow]	Moscow	8 550	3 343 645	0.3910
56	Moskovskoe	TGC-3	CHPP-27 [Moscow]	Moskovskaya Oblast	1 162	397 284	0.3420
57	Moskovskoe	TGC-3	CHPP-28 [Moscow]	Moscow	83	29 807	0.3591
58	Moskovskoe	TGC-3	CHPP-29 (GTU-	Moskovskaya Oblast	0	0	0
59	Moskovskoe	CHP VTI	CHPP VTI	Moscow	61	54 428	0.8958
60	Ivanovskoe	TGC-6	Ivanovskaya CHPP-1	Ivanovskaya Oblast	45	20 816	0.4644
61	Ivanovskoe	TGC-6	Ivanovskaya CHPP-2	Ivanovskaya Oblast	536	392 230	0.7315
62	Ivanovskoe	TGC-6	Ivanovskaya CHPP-3	Ivanovskaya Oblast	953	544 217	0.5710
63	Ivanovskoe	BE-ServCce	Experimental stand	Ivanovskaya Oblast	180	111 243	0.6185
64	Yaroslavskoe	TGC-2	Yaroslavskoe CHPP-	Yaroslavskaya Oblast	394	255 940	0.6490
65	Yaroslavskoe	TGC-2	Yaroslavskoe CHPP-	Yaroslavskaya Oblast	734	472 144	0.6430
66	Yaroslavskoe	TGC-2	Yaroslavskoe CHPP-	Yaroslavskaya Oblast	1 097	637 955	0.5817
67	Tverskoe	OGC-5	Konakovskaya TPP	Tverskaya Oblast	8 149	4 429 410	0.5435
68	Tverskoe	TGC-2	Tverskaya CHPP-1	Tverskaya Oblast	55	45 753	0.8279
69	Tverskoe	TGC-2	Tverskaya CHPP -3	Tverskaya Oblast	973	472 990	0.4863
70	Tverskoe	TGC-2	Tverskaya CHPP-4	Tverskaya Oblast	356	222 505	0.6242
71	Tverskoe	TGC-2	Vyshnevolockaya	Tverskaya Oblast	13	11 368	0.8678
72	Kostromskoe	OGK-3	Kostromskaya TPP	Kostromskaya Oblast	12 359	6 428 826	0.5202
73	Kostromskoe	TGC-2	Kostromskaya	Kostromskaya Oblast	92	72 412	0.7846
74	Kostromskoe	TGC-2	Kostromskaya	Kostromskaya Oblast	967	497 989	0.5151
75	Kostromskoe	TGC-2	CHPP Sharinskaya	Kostromskaya Oblast	26	34 729	1.3241
76	Vologodskoe	OGK-6	Cherepobeckaya TPP	Vologodskaya Oblast	3 027	2 707 936	0.8947
77	Vologodskoe	TGC-2	Vologodskaya CHPP	Vologodskaya Oblast	81	56 575	0.7024
Total					**132 330**	**72 213 168**	**0.5457**

Table Annex.2.3. Build Margin (most recently built plants)

	Company	Installation	Year of beginning of operation	EFCO2	EFCH4
				tCO_2/MWh	tCH_4/MWh
1	Objekty BE "Servis"	OAO Kaliningradskaya TEC-2	2005	0.4360	0.0072
2	Objekty BE "Servis"	Ivanovskiye PGU	2007	0.4667	0.0078
3	OAO" Sotchinskaya TEC"	Sotchinskaya TEC	2004	0.4446	0.0074
4	TGK-10	Tyumenskaya PGU-190/220 st.No.1	2004	0.4371	0.0072
5	TGK-4	GTU TEC LUTCH	2005	0.3789	0.0063
	Weighted average			**0.4343**	**0.0072**

Table Annex.2.4. Calculation of Operation Margin EF CO_2 in OES North-West

OES North-West	**Unit**	**2006**
Electricity production	thous.MWh	34 267
CO_2 emission	tCO_2	21 273 983
$\mathbf{EF_{OMsimple,2006}}$	$\mathbf{tCO_2/MWh}$	**0.6208**

Table Annex.2.5. Calculation of Operation Margin EF CO_2 in OES Center

OES Center	**Unit**	**2006**
Electricity production	thous.MWh	132 330
CO_2 emission	tCO_2	72 213 168
$\mathbf{EF_{OMsimple,2006}}$	$\mathbf{tCO_2/MWh}$	**0.5457**

Table Annex.2.6. Calculation of the weighted average Operation Margin EF CO_2

	Year	2 006	
		OES North-West	OES Center
$EF_{OMsimple,2006}$	**tCO_2/MWh**	**0.6208**	**0.5457**
weight		**0.796**	**0.204**
Operation Margin EF CO_2 (weighted average)	**tCO_2/MWh**	**0.6055**	

Table Annex.2.7. Calculated baseline emission factor for grid electricity system (OES North-West + OES Center) $EF_{grid,CM,y}$

Year		2008	2009	2010	2011	2012
$EF_{grid,OM,y}$	tCO_2/MWh	0.6055	0.6055	0.6055	0.6055	0.6055
$EF_{grid,BM,y}$	tCO_2/MWh	0.4343	0.4343	0.4343	0.4343	0.4343
$EF_{grid,CM,y}$	**tCO_2/MWh**	**0.5199**	**0.5199**	**0.5199**	**0.5199**	**0.5199**

Table Annex.2.8. Basic data of Alternative 6 (Baseline of project)

Indicators	2008	2009	2010	2011	2012
Annual fuels consumption in Kirishskaya TPP (KES-PT), tce	**2 126 644**	**2 121 948**	**1 958 182**	**1 523 811**	**1 512 659**
Natural Gas, tce	1 731 245	1 727 422	1 594 105	1 240 495	1 231 416
Natural Gas, thousand m^3	1 509 180	1 505 848	1 389 631	1 081 378	1 073 463
HFO, tce	395 399	394 526	364 077	283 317	281 243
HFO, t	291 347	290 703	268 268	208 760	207 232
Annual fuels consumption per electricity production, tce	2 126 644	2 121 948	1 958 182	1 523 811	1 512 659
Specific fuel consumption per electricity unit KES-PT, g/kWh	348.4	348.4	348.4	348.4	348.4
Annual output electricity KES-PT, MWh	**6 104 030**	**6 090 552**	**5 620 500**	**4 373 741**	**4 341 730**
NG LHV, MJ/Nm^3	33.62	33.62	33.62	33.62	33.62
HFO LHV, MJ/kg	39.77	39.77	39.77	39.77	39.77
Efficiency -electricity production	35.3%	35.3%	35.3%	35.3%	35.3%
NG EF CO_2, tCO_2/TJ	56.1	56.1	56.1	56.1	56.1
HFO CO_2, tCO_2/TJ	77.3	77.3	77.3	77.3	77.3
CO_2 Emission (electricity production KES-PT) , tCO_2	**3 723 494**	**3 715 272**	**3 428 538**	**2 668 007**	**2 648 480**
Combined $EFCO_2$(replaceable electricity), tCO_2/MWh	0.5199	0.5199	0.5199	0.5199	0.5199
Replaceable electricity, MWh	0	0	0	3 483 043	3 488 846
CO_2 Emission (replaceable electricity), tCO_2	**0**	**0**	**0**	**1 810 860**	**1 813 877**
Baseline GHG Emission, (tCO_2)	**3 723 494**	**3 715 272**	**3 428 538**	**4 478 868**	**4 462 358**

KES-PT = condensing plant

Table Annex.2.9. Capacity and production in power plant from 2007 to 2025 with reconstruction of energy block No.6

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025
Electricity											
Production mln. kWh	7 074	7 873	7 872	6 999	9 800	9 800	9 800	9 800	9 800	9 950	9 950
KES-PT	5 744	6 521	6 507	5 621	3 894	3 866	3 837	3 807	3 779	3 776	3 776
TEC	1 330	1 352	1 365	1 379	1 406	1 435	1 463	1 493	1 522	1 675	1 675
PGU	0	0	0	0	4 500	4 500	4 500	4 500	4 500	4 500	4 500
Installed capacity, GW	2.1	2.1	2.1	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
KES-PT	1.8	1.8	1.8	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
TEC	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
PGU				0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Number of hours in operation	3 368	3 749	3 749	2 692	3 769	3 769	3 769	3 769	3 770	3 827	3 827
KES-PT	3 191	3 623	3 615	3 747	2 596	2 577	2 558	2 538	2 519	2 517	2 517
TEC	4 433	4 506	4 551	4 596	4 688	4 782	4 877	4 975	5 074	5 582	5 582
PGU					5 625	5 625	5 625	5 625	5 625	5 625	5 625
Heat											
Effective output, thous. Gcal	2 647	2 652	2 137	2 141	2 253	2 885	2 997	3 108	3 220	3 700	3 700

Source:
ОАО "СЕВЗАП НТЦ": Реконструкция энергоблока №6 Киришской ГРЭС на базе парогазовой установки; Технико-экономическое обоснование; Пояснительная записка; 617.ПТ-00.000.009; Том 9; 2007 - Таблица 1

KES-PT = condensing plant
TEC = CHP
PGU = combined cycle gas turbine

Annex 3

MONITORING PLAN

Form 6-TP

FEDERAL STATE STATISTICAL OBSERVATION

THE CONFIDENTIALITY IS PROVIDED BY THE INFORMATION RECEIVER

Non submission of information brings to account statute-established by the Law of the Russian Federation «On responsibility of breaching of order of State statistical accounting» No. 2761-1 dated 13.05.92

DATA ABOUT CHPP OPERATION FOR
20__

Submitting:	Date of submitting
TPPs and regional boiler-houses of the RAO UESR and AO-energos irrespective of capacity: - of higher organization	January 21
AO-energos of RAO UESR and subsidiaries of RAO UESR: – the body of the State Statistics on the place, established by the territorial body of Federal Statistical Committee of the Russian Federation in the republic, territory, region, city of federal value; – Economy department of RAO UESR and associated companies of RAO UESR; – governmental regulation body in the respective economics sector ; – regulation body of natural monopoly in the respective economics sector	February 7
other power plants with 500 kBW capacity and more: – the body of the State Statistics on the place, established by the territorial body of Federal Statistical Committee of the Russian Federation in the republic, territory, region, city of federal value; – Economy department of RAO UESR and associated companies of RAO UESR; – governmental regulation body in the respective economics sector ; – regulation body of natural monopoly in the respective economics sector	January 21

Form 6-TP

Approved by Regulation of the Federal Statistical Committee of the Russian Federation No. 54 dated 27.07.2001

Annual

Company name ____

Postal address
____

Code of form on OKUD	Code (stated by the reporting organization)							
	Reporting organization on OKPO	Kind of activity on OKDP	Sector on OKONKh	Territory on OKATO	Ministry (department), authority on OKOGU	Legal form on OKOPF	Property form on OKFS	Power plant category
1	2	3	4	5	6	7	8	9
0610095								

Charter 1. General data

Code on OKEI: kW - 214; Gcal/h - 238; hour - 356

Parameters	No of string	Installed capacities of TPPs at the end of year			Value and a cause of change of the installed capacity	Available capacities of TPPs at the end of year		Average installed capacities of the reporting year	
		power, kW	heat, Gcal/h			power, kW	Heat by turbo-units, Gcal/h	power, kW	Heat by turbo-units, Gcal/h
			total	Including by turbounits					
A	B	1	2	3	4	5	6	7	8
Actually	11								

Parameters	No of string	Average working power capacity of the reporting year, kW	The number of hours of utilization of the average annual installed power capacity, h (row2 gr.1 : row 1 gr.7) x 1000)	The number of hours of utilization of the average annual installed heat capacity of turbounits, h	Maximum of load		Technical causes of limitation of the installed capacity of TPP
					power, kW	heat, Gcal/h	
A	B	9	10	11	12	13	14
Actually	11						

Charter 2. Operational data

Code on OKEI: thous. kWh - 246; Gcal - 233

Parameters	No of string	Power production, thous. kWh		Heat output to external consumers, Gcal				Electricity auxiliary power consumption, thous. kWh		
		total	Including district heating cycle	total (gr.4 + gr.6)	From TPP		From district boiler-house of RAO UESR and AO-energo	For TPP		For district boiler-house of RAO UESR and AO-energo
					total	Including with spent steam		for electricity production	for heat output	
A	Б	1	2	3	4	5	6	7	8	9
Actually	22									
	23									

Code on OKEI: thous. kWh - 246; g/kWh - 510; kg/Gcal - 511

Parameters	No of string	Power output, thous. kWh (gr.1 - (gr.7+ gr.8))	Specific consumption of fuel equivalent				Specific electricity auxiliary power consumption		
			for electricity supplied, g/kWh	for heat supplied, kg/Gcal			for electricity production (gr.7:gr.1)x100	For heat output, kWh/Gcal	
				total	For TPP	For district boiler-house of RAO UESR and AO-energo		For TPP (gr.8 : gr.4) x 1000	For district boiler-house of RAO UESR and AO-energo (gr.9 : gr.6) x 1000
A	B	10	11	12	13	14	15	16	17
Standard	21	X					X	X	X
Actually	22								
	23								

18 ____________ 19 ____________

Charter 3. Fuel consumption of fuel equivalent for power and heat output

Code on OKEI: tce - 172

Expended fuel	No of string	On standard for actual output	Actually	Saving (-); surcharge (+); (gr.1 - gr.2)
A	B	1	2	3
Total (string 32 + string 33)	31			
For power output	32			
For heat output - total (string 34 + string 35)	33			
including: at TPP	34			
at district boiler-house of RAO UESR and AO-energo	35			
	36			

Charter 4. Fuel Balance

Fuel type	No of string	Units	Code on OKEI	Remaining fuel at the beginning of the year	Fuel receipt for the year	Fuel consumption for the year			Remaining fuel by the end of the year	Quality of burned fuel		
						Total	Including for power and heat output			Fuel heating value (Q_p), kcal/kg (kcal/nm^3)	Moisture content (W_p), %	Ash content (A_p), %
							natural	equivalent				
A	B	C	D	1	2	3	4	5	6	7	8	9
Heavy oil	41	t	168									
including: fuel oil	42	t	168									
Gas	43	thous. m^3	114	X					X			X
Coal - total	44	t	168									
Including coal on type and rank												
From total quantity of coal: Black coal	45	t	168									
Peat – total	46	t conditional moisture	179									
Shales - total	47	t	168									
Firewood	48	solid м^3	121									
Other fuel type	49											
Total 1)	50			X	X	X	X		X	X	X	X

1) Fuel consumption under string «Total» gr.5 is to be equal fuel consumption stated in the string 31 gr.2 charter 3.

Head of organization ______________ *(Name)* ______________ *(signature)*

Functionary,

responsible for the form filling in

	___________________ *(Position)*	___________________________ *(Name)*	_______________ *(signature)*
	___________________ *(contact telephone)*	«____» _________20__ *(date of document making)*	