



JOINT IMPLEMENTATION PROJECT DESIGN DOCUMENT FORM
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**SECTION A. General description of the project****A.1. Title of the project:**

“Installation of CCGT-400 at Shaturskaya TPP, OGK-4, Moscow area, Russia”.

Sectoral scope 1: Energy industries¹.

PDD version 3.1.

13 October 2009.

A.2. Description of the project:

OJSC “Fourth Generation Company of the Wholesale Electricity Market” (further in the text - OGK-4 in line with the Russian abbreviation) is one of the six thermal OGKs established during the Russian electricity sector reform. OGK-4 was incorporated in 2005 and completed the process of its corporate reorganization in 2006. E.ON Russia Power became owner of around 69% stock at the end of 2007. E.ON Russia Power owned 76% of stock by the end of 2008.

The OGK-4 Company core business is generation and wholesale of electricity. Generation, transmission and sale of heat are not crucial as it constitutes only around 2% of sales revenues.

The Company operates five thermal power plants (TPP) throughout Russia: Berezovskaya TPP (1,500 MW, Sharypovo, Krasnoyarsk territory), Surgutskaya TPP-2 (4,800 MW, Surgut, Tyumen area), Yajvinskaya TPP (600 MW, Yajva, Perm area), Shaturskaya TPP (1,100 MW, Shatura, Moscow area) and Smolenskaya TPP (630 MW, Ozerny, Smolensk area) each being a branch of the Company since 1 July 2006.

Total installed generation capacity of OGK-4 is 8,630 MW (that accounts for about 4% Russia’s total installed power capacity) and total installed thermal generation capacity is 2,179 Gcal/h. OGK-4 produced 56,676 MWh of electricity and 2,261 Gcal of heat in 2008. Gas accounted for 79% of the energy balance.

Shaturskaya TPP started operation in 1925 with installed capacity of 48 MW, based on peat and coal and was one of the thirty TPPs included in the First Plan of Energy System Development in the Soviet Union (GOELRO in Russian). In the 1970-s and 1980-s the capacity was increased and modernized and the fuel was gradually switched to natural gas in the 1980-s.

Currently Shaturskaya TPP is the third biggest branch of OGK-4. The installed electricity capacity is 1,100 MW and the heat capacity is 343.4 Gcal/h. The Company produced 9% of energy generated by OGK-4 in 2008 and operates mostly (95%) on natural gas. The Company produces 20% of the energy in Moscow area and 100% of heat in the town Shatura. The main technical data of the existing energy units is presented in the Table A.2.1 below.

¹ http://ji.unfccc.int/Ref/Documents/List_Sectoral_Scopes_version_02.pdf

Table A.2.1: Main technical data of existing energy units at Shaturskaya TPP

N	Type of energy unit	Amount	Unit capacity, MW	Commissioning year	Turbine type	Boiler type	Fuel
1-3	Two-boiler single-turbine units	3	200	1971-1972	K-200-130	TP (TII)-108	Peat, coal, gas, heavy fuel oil
4-5	One-boiler single turbine unit	2	210	1977-1986	K-210-130	TM-104A	Gas, heavy fuel oil
6	Cogeneration unit	1	80	1986	PT (IIT)-80-130	BKZ (BK3)-320-140	Gas, heavy fuel oil
-	Hot-water boiler	2		1990	-	KVGM (KBGM)-50	Gas, heavy fuel oil

Source: OGK-4

The project is to be implemented at Shaturskaya Thermal Power Plant. It is planned to build an additional electricity generating unit using the Combined Cycle Gas Turbine (CCGT) which is the most energy efficient and environmentally sound way of energy generation as of today. The purpose of this project is to demonstrate the utilisation of a Best Available Technology (BAT) and to decrease the specific CO₂ emissions per MWh generated and other negative anthropogenic impact.

Project scenario

A combined cycle gas turbine unit with electricity capacity of 400 MW will be installed at Shaturskaya TPP and commissioned in September 2010. The efficiency of new energy unit is expected to be approximately 56%. Natural gas will be used as fuel. After project implementation the new energy unit will supply electricity to the United Regional Energy System (URES) "Centre" grid (description of URES is provided in Annex 2). Electricity produced by the new generating unit, based on more efficient technology of energy generation, will replace electricity that would be generated using less efficient technology in case of the absence of the unit.

Baseline scenario

The baseline scenario is based on the assumption that if the project is not implemented (i.e. additional electricity will not be supplied to the grid) third parties will cover the energy demand. The energy companies within the same regional energy system can increase electricity generation at the existing capacities by delaying decommissioning of outdated capacity and/or installing new energy units.

According to paragraph 20 (b) of the "Guidance on criteria for the baseline setting and monitoring" the project participants: "...may establish a baseline 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."

In the proposed project a JI specific approach to set the baseline scenario and the monitoring plan is used. The specific approach will be based on elements of CDM methodologies and the CDM Tool "Tool to calculate project emissions from electricity consumption". The justification of JI specific approach is presented more in detail in Section B.1 and Annex 2.

Brief history of the project

The Russian United Energy Company (in Russian- RAO "UES") paid a lot of attention to the cooperation within Kyoto Protocol to UNFCCC. The GHG inventory has been performed in all regional



branches. Company seriously considered introduction of internal emission trading system (ETS). It created special entity for PIN and PDD development – Energy Carbon Fund (ECF). When investment programs or interventions were planned and approved by its Board the potential implications of this cooperation were taken into account. This was reflected in the titles of investment projects. Most of the projects with CCGT installation were entitled as “Creating the Replacing Capacity by CCGT installation at...”. It was expected that some old generating capacities would be replaced after 2020 or earlier. When OGK-4 was created in 2005 it inherited the old investment programs adjusting their scope and funding but not the titles of interventions and projects.

The decommissioning activities of some installations are not planned at Shaturskaya TPP as it is located in one of the most energy deficient areas and then OGK-4 is one of the wholesale generating companies having the modern recently installed (in comparison with the average age of this type of equipment in Russia) energy generating installations. The decision on funding and implementing the project under the title “Creating the Replacing Capacity by CCGT-400 Installation at Shaturskaya TPP, OGK-4” was taken by OGK-4 Management Board (approval of project feasibility study) in June 2007. The PIN for this project was developed by ECF in February 2007. After approval of project feasibility study OGK-4 made a contract with consortium of “General Electric International” and “Gama Guc Sistemleri Muhendislik Ve Taahut A.S.” for project implementation. OGK-4 waited for JI National Approval Procedure to be in place in Russia. After its launch in February 2008 OGK – 4 and its new owner – E.ON Russia Power decided to update the PINs and to prepare prefeasibility study for those PINs in three OGK-4 affiliates inclusive Shaturskaya TPP.

As a result of this study OGK-4 decided to start the full JI cycle but having the project under the title “Installation of CCGT-400 at Shaturskaya TPP, OGK-4, Moscow area, Russia” that more precisely reflects the project scope and follows the rules of titling the JI projects. In all JI cycle related documents it will be under this title while supporting documents provided upon the request to Determinator, National authorities and international organizations will have the original title presented above.

A.3. Project participants:

Party involved	Legal entity <u>project participant</u> (as applicable)	Please, indicate if the <u>Party involved</u> wishes to be considered as <u>project participant</u> (Yes/No)
Party A: Russia (Host party)	OJSC “Fourth Generation Company of the Wholesale Electricity Market”	No
Party B: Germany	E.ON Carbon Sourcing	No

Role of the Project Participants:

- OJSC “Fourth Generation Company of the Wholesale Electricity Market” (OGK-4) – will manage and partly fund JI project implementation at Shaturskaya TPP including monitoring plan. It will own ERUs generated. OGK-4 is a project participant;
- E.ON is one of the biggest investor-owned companies, involved in production, supply and sales of different types of energy, heat and natural gas with operations in Germany, UK, Italy, Spain, Sweden, Russia and USA. Its Euro 87 billion sales were generated by around 94 thousand employees in 2008. It is deeply involved in cooperation within Kyoto Protocol and had created special business unit “E.ON Carbon Sourcing”, 100% subsidiary of “E.ON Climate & Renewables” for these

purposes. It funds JI project investment cost and will use ERUs generated. “E.ON Carbon Sourcing” is a project participant.

JI consultant:

Global Carbon BV is a leading expert on environmental consultancy and financial brokerage services in international greenhouse emissions trading market under Kyoto Protocol. Global Carbon BV is a project design document (PDD) developer including monitoring plan and baseline setting. Global Carbon BV has developed the first JI project that has been registered at United Nations Framework Convention on Climate Change (UNFCCC). The first verification under JI mechanism was also completed for Global Carbon BV project. Company has four offices and focuses on Joint Implementation (JI) project development in Bulgaria, Ukraine, Russia, and the EU Emissions Trading Scheme. Global Carbon BV is responsible for the preparation of the investment project as a JI project including PDD preparation, obtaining Party approvals, monitoring and transfer of ERUs. Global Carbon BV is not a Project Participant.

A.4. Technical description of the project:

A.4.1. Location of the project:

The project is located in Shatura town (55°34' longitude, 39°32' latitude) in the east of Moscow area (about 125 km from Moscow) in the European part of Russia. The geographical location of the Shatura town and Moscow area in Russia is presented in Figure A.4.1.1 and Figure A.4.1.2 below.

Figure A.4.1.1: Map of Moscow region with location of Shatura (in oval)



Source: http://map.rin.ru/cgi-bin/main_e.pl?Region=moscowl.

Figure A.4.1.2: Map of Russia with location of Moscow region (selected by brown colour)



Source: <http://map.rin.ru/>

A.4.1.1. Host Party(ies):

The Russian Federation.

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

The Moscow Area (in Russian language – oblast) is the area that surrounds Moscow City but excludes Moscow City itself. The Moscow area is the third biggest area (in terms of the Gross Regional Product (GRP)) in the Russian Federation, after Moscow and Tyumen region, and accounts for 4% of GDP, 5% of country population but less than 0.3% of the surface. 81% of the population is settled in 80 cities and the remaining 19% of the population resides in country-like communities. The Moscow area has a huge innovative potential as more than 50% of Russian “Scientific Centres” (towns) are located here. The area has highly diversified machinery building, metal works, chemistry and light industry and full-fledged infrastructure. It is considered to be one of the most energy deficient regions due to highly developed economical infrastructure with growing energy demands.

Several big power plants are located in the Moscow area:

- Kashirskaya TPP (1580 MW, branch of OJSC “OGK-1”);
- Dzerginskaya CHP (1300 MW), CHP-27 (610 MW) (branch of OJSC “TGK-3 (Mosenergo));
- Zagorskaya GAES² (1200 MW, branch of OJSC “RusGidro”);
- Shaturskaya TPP (1100 MW, branch of OJSC “OGK-4”).

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

Shaturastry settlement was founded in 1919 (from 1936 – town). Shatura town is the capital of Shatursky region that borders with Vladimir and Ryazan areas. Shatura is a small town with a population of 31 thousand people and ranked 48 in the Moscow area. It produces less than 1% of the GRP. Its

² GAES is Russian abbreviation of hydroelectric pumped storage power plant

prosperity is based on the existence of Shaturskaya TPP, furniture factory, reinforced concrete production, transport and civil construction companies.

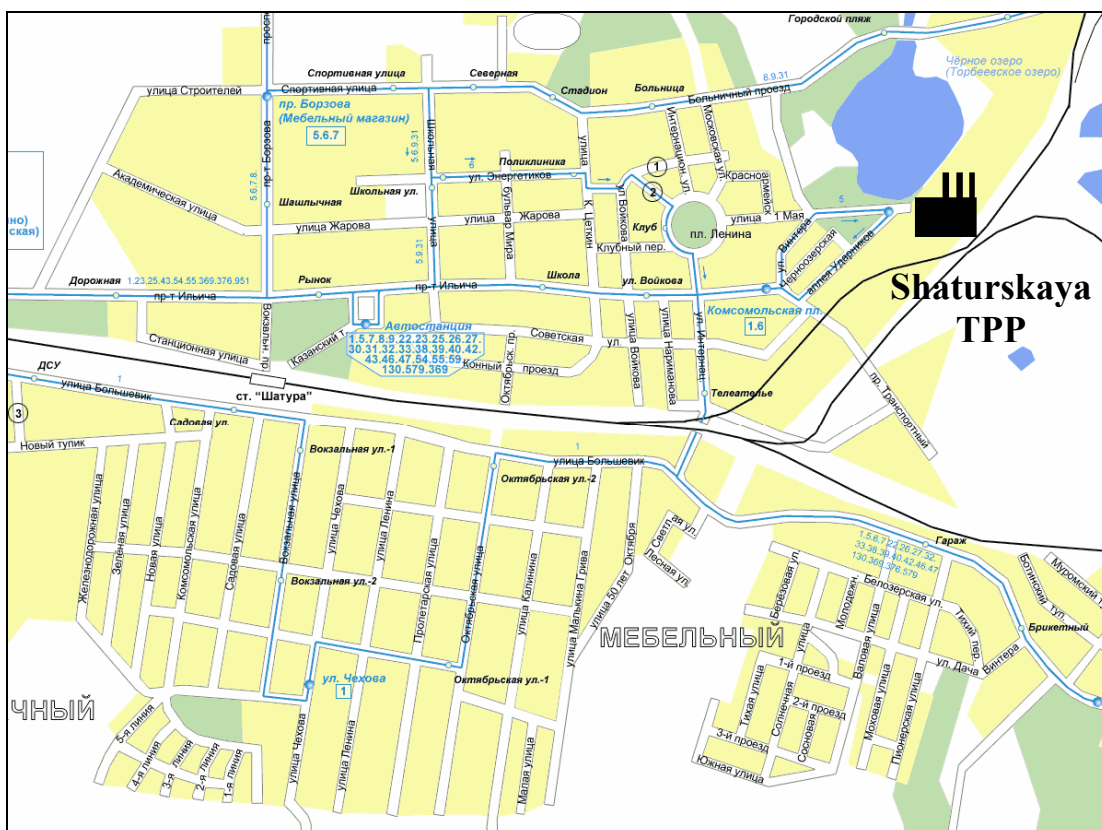
Shaturskaya TPP contributes 34% to Shatursky region GRP and employs about 10% of labour force in the town. Average salary in the region is around RUR 19 thousand and the unemployment rate is 2%. Average salary at Shaturskaya TPP is RUR 25,000 (which is higher than average) and it provides better working conditions to the staff. Shaturskaya TPP is the only centralized heat supplier to the residential area and enterprises and the dominant electricity generator.

Shaturskaya TPP annual contribution to the town's budget revenues amounts to 12%. So it plays important social and economic role in the region.

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

Shaturskaya TPP is located within the Shatura town boundaries in its north-western part (about 2 km from the Centre). Its location is presented on the Figure A.4.1.3 below. The coordinates of TPP are 55°45'N, 39°44'E.

Figure A.4.1.3: Location of Shaturskaya TPP



Source: <http://planetolog.ru/maps/city/big/shatura.gif>.

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

A combined cycle is characteristic of a power producing engine or plant that employs more than one thermodynamic cycle. Heat engines are only able to use a portion of the energy their fuel generates (usually less than 50%). Normally the remaining heat (e.g. hot exhaust fumes) from combustion is wasted. Combining two or more "cycles", such as the Brayton cycle and the Rankine cycle, results in improved overall efficiency.

In a combined cycle power plant (CCPP), or combined cycle gas turbine (CCGT) plant, a gas turbine generator generates electricity and the waste heat is used to make steam to generate additional electricity via a steam turbine; this last step enhances the efficiency of electricity generation. Most of the new gas power plants in North America and Europe are of this type, whereas in Russia this is not the case. In a thermal power plant, high-temperature heat as input to the power plant, usually from burning of fuel, is converted to electricity as one of the outputs and low-temperature heat as another output. As a rule, in order to achieve high efficiency, the temperature difference between the input and output heat levels should be as high as possible. This is achieved by combining the Rankine (steam) and Brayton (gas) thermodynamic cycles.

Efficiency of CCGT plants

By combining both gas and steam cycles, high input temperatures and low output temperatures can be achieved. Efficiency of cycles sums up, because they have the same fuel source. So, a combined cycle plant has a thermodynamic cycle that operates between the gas-turbine's high firing temperature and the waste heat temperature from the condensers of the steam cycle.

If the CCGT plant produces only electricity, efficiencies of up to 60% theoretically may be achieved. Projected plant efficiency is expected 56% under nominal operational parameters.

The proposed project uses General Electric STAGTM (Steam and Gas) combine-cycle power system. The type of system is S109FA with MS9001FA gas turbine system (simple cycle performance) and F class steam turbine. It includes one gas turbine (model is PG9351FA), one steam turbine (D10), one generator (390H), one triple pressure heat recovery steam generator (CMI) and auxiliary equipments.

The technical characteristics of the combine-cycle power system are described in the Table A.4.2.1 below.

Table A.4.2.1: Relevant technical data of combine-cycle power system

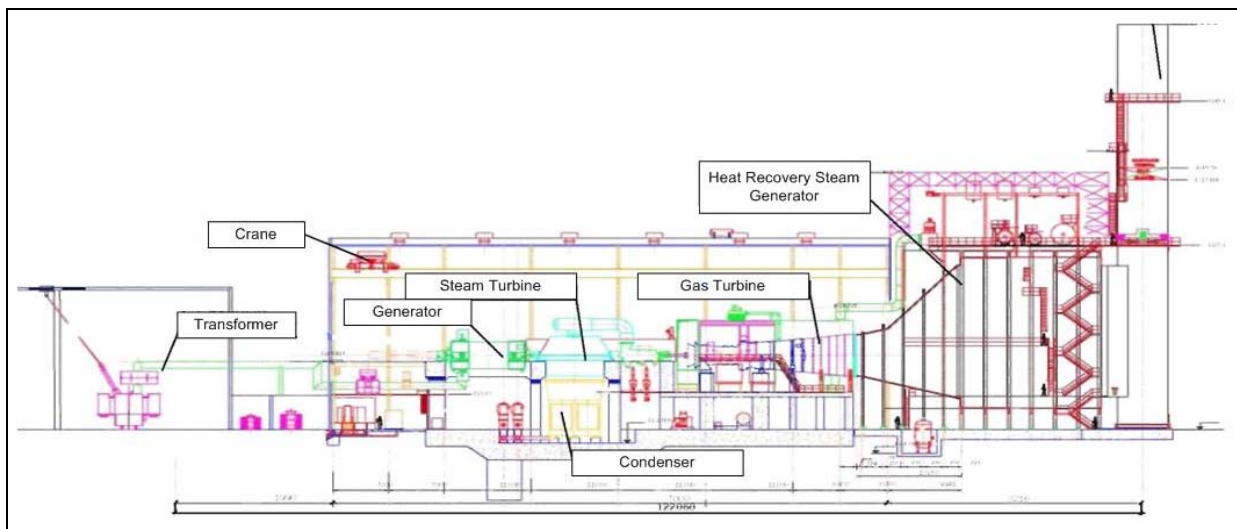
Indicator	Amount	Units
S109FA		
Fuel	Natural gas	-
Installed capacity	400	MW
Net efficiency	55.93	%
	6,437	kJ/kWh
MS9001FA		
Model Designation	PG9351FA	-
Installed capacity	270	MW
Turbine Speed	3,000	rpm
Heat Rate	9,757	kJ/kWh
Exhaust Temperature	600	°C
CMI		
High pressure steam output	265.0	t/h
Intermediate pressure steam output	58.0	t/h
Low pressure steam output	43,6	t/h
D10		

Indicator	Amount	Units
Installed capacity	130	MW
390H		
Capacity	400	MW

Source: Data provided by OGK-4

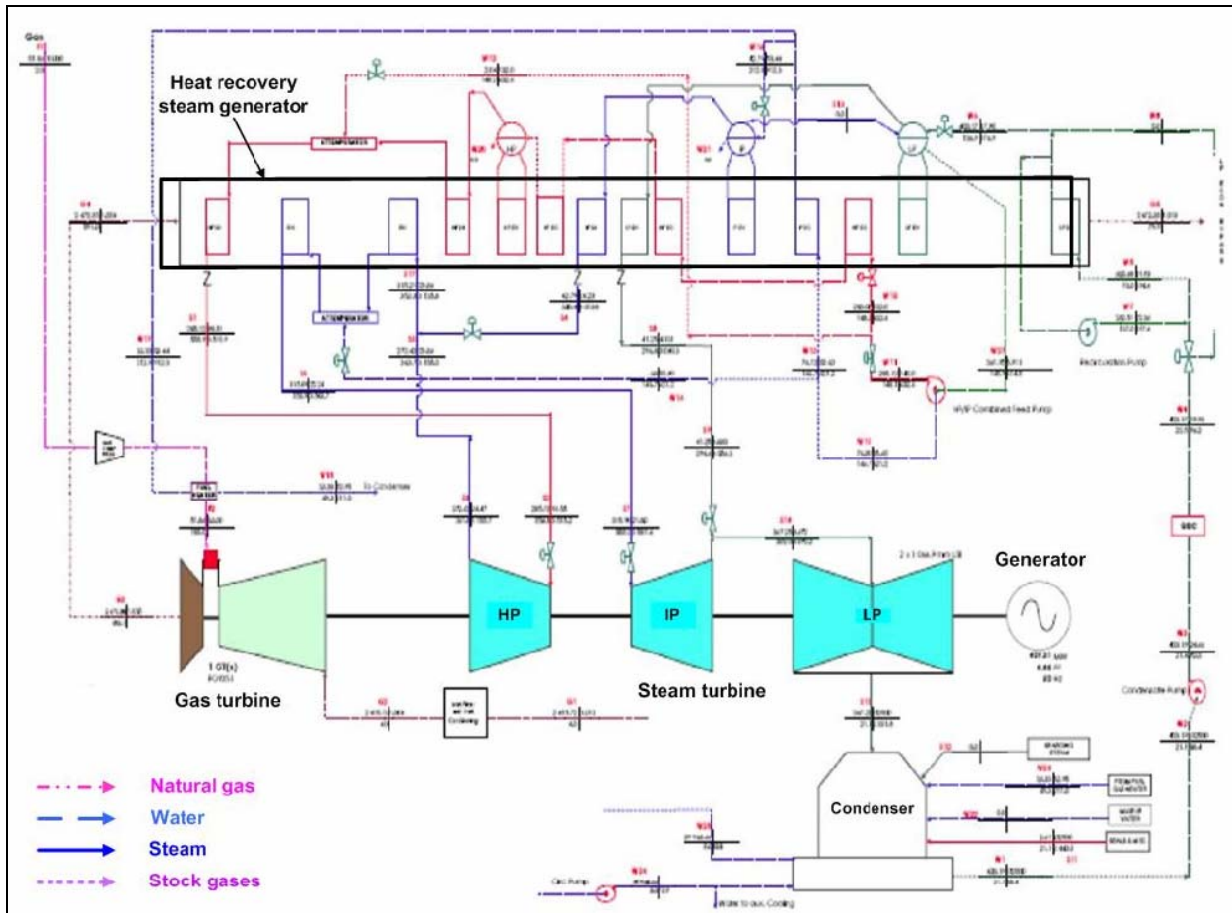
The S109FA design at Shaturuskaya TPP (Figure A.4.2.1), the heat scheme of S109FA at Shaturuskaya TPP (Figure A.4.2.2) and the MS9001FA simple cycle performance (Figure A.4.2.2) are presented below.

Figure A.4.2.1: S109FA design at Shaturuskaya TPP



Source: Data provided by OGK-4

Figure A.4.2.2: Heat scheme of S109FA at Shaturskaya TPP



Source: Data provided by OGC-4

Figure A.4.2.3: MS9001FA simple cycle performance



Source: http://www.gepower.com/prod_serv/products/gas_turbines_cc/en/downloads/gasturbine_cc_products.pdf

Implementation schedule

According to the schedule the modernization will be commissioned by September 2010. The project implementation schedule is presented in the Table A.4.2.2.

Table A.4.2.2: Project implementation schedule

N	Title	2006				2007				2008				2009				2010							
		I	II	III	IV	I	II	III	IV	I	II	III	IV	I	II	III	IV	I	II	III	IV				
1	Decision making		■																						
2	Site preparation			■																					
3	Conclusion of contract					■																			
2	Project development and permits					■																			
3	Equipment procurement							■																	
5	Civil works					■																			
6	Commissioning																			■					

Source: Data provided by OGK-4.

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 project uses one of the best available technologies of electricity generation: combined cycle electricity generation. Its efficiency is approximately 56% and the emission factor is 0.361 tCO₂/MWh. After the project implementation electricity generated by the new energy unit will be supplied to the grid of URES “Centre”. It will replace electricity which otherwise would have been generated by the existing power plants and/or other new energy units to be constructed by the third parties. The Combined Margin emission factor (existing power plants and new energy units) is 0.540 tCO₂/MWh.

The project does not look financially attractive as it is proved in Section B.2 through the application of the appropriate investment analysis as per the approved CDM “Tool for the demonstration and assessment of additionality” (version 05.2). The energy industry is a capital intensive industry and the proposed project requires a significant amount of funding (more than Euro 380 million). The IRR benchmark used in the investment analysis is 12%, while in the proposed project (not being implemented as a JI project) the IRR will be only 1.80%. For more detailed information on baseline setting and additionality, please refer to Section B.

Therefore if the project is not implemented, more greenhouse gases will be emitted to supply the same amount of electricity.

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

	Years
Length of the <u>crediting period</u> within 2008-2012	2.3
Year	Estimate of annual emission reductions in tonnes of CO ₂ equivalent
2010	147,251
2011	490,837
2012	490,837
Total estimated emission reductions over the <u>crediting period</u> (tonnes of CO ₂ equivalent) within 2008 – 2012	1,128,924
Annual average of estimated emission reductions over the <u>crediting period</u> (tonnes of CO ₂ equivalent) within 2008 – 2012	490,837

	Years
Period after 2012, for which emission reductions are estimated	8
Year	Estimate of annual emission reductions in tonnes of CO ₂ equivalent
2013	490,837
2014	490,837
2015	490,837
2016	490,837
2017	490,837
2018	490,837
2019	490,837
2020	490,837
Total estimated emission reductions over the period indicated (tonnes of CO ₂ equivalent)	3,926,693

Detailed calculation of project emission reductions is presented in Section E.

A.5. Project approval by the Parties involved:

After the PDD has passed the preliminary determination process, the PDD, the Determination report and other relevant documents will be submitted to the Russian Ministry of Economic Development to follow the procedure of project approval as JI by the Government of the Russian Federation. Additionally, project approval from Germany will be sought.

**SECTION B. Baseline****B.1. Description and justification of the baseline chosen:****Indication and description of the approach chosen regarding baseline setting**

A baseline for a JI project has to be set in accordance with Appendix B of the Annex to decision 9/CMP.1 (JI guidelines), and with the “Guidance on criteria for baseline setting and monitoring”³ developed by the Joint Implementation Supervisory Committee (JISC) (hereinafter referred to as “Guidance”). In accordance with this Guidance, the project participants may apply approved CDM baseline and monitoring methodologies (paragraph 20 (a) of the Guidance) or they can establish a baseline in accordance with Appendix B of the JI guidelines, while also using selected elements or combinations of approved CDM baseline and monitoring methodologies as appropriate (paragraph 20 (b) of the Guidance).

According to UNFCCC website there are 37 CDM approved methodologies for Energy industries (<http://cdm.unfccc.int/DOE/scopes.html#1>, excluding small scale projects).

A JI specific approach regarding baseline setting and monitoring has been developed in accordance with Appendix B of the JI Guidelines and with the JISC Guidance. This specific approach will use elements of CDM methodologies (AM0029 “Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas” and ACM0013 “Consolidated baseline and monitoring methodology for new grid connected fossil fuel fired power plants using a less GHG intensive technology”) and the CDM Tool “Tool to calculate project emissions from electricity consumption”.

The baseline is the scenario that reasonably represents the anthropogenic emissions by sources of greenhouse gases that would occur in the absence of the proposed project⁴. Plausible future scenarios are identified and listed on the basis of conservative assumptions (paragraph 21 (b) of the Guidance). The proposed project, not developed as a JI project, has been included as one of the alternatives. These alternatives are assessed as credible or plausible, and the most plausible is identified as the baseline. The consistency between the baseline scenario determination and additionality determination has been checked.

The proposed approach is being applied through the following three steps:

1. Identification of a baseline in accordance with paragraphs 21-26 of the Guidance;
2. Additionality demonstration in accordance with the most recent version (version 05.2) of the “Tool for the demonstration and assessment of additionality”;
3. Calculation of a multi-project emission factor in accordance with paragraphs 18-20 of the Guidance using the CDM Tool “Tool to calculate project emissions from electricity consumption”.

Step 1: Identification of a baseline based on the selection of the most plausible alternative scenario***Sub-step 1a: Identification and listing of plausible alternative baseline scenarios***

Based on the JI specific approach presented above seven possible alternative baseline scenarios are identified:

Alternative scenario 1: The proposed project not developed as a JI project;

³ <http://ji.unfccc.int/Ref/Guida.html>

⁴ JI guidelines, appendix B



- Alternative scenario 2: Construction of steam turbines of 400 MW in total with gas fired boiler(s);
- Alternative scenario 3: Construction of steam turbines of 400 MW in total with coal fired boiler(s);
- Alternative scenario 4: Construction of steam turbines of 400 MW in total with peat fired boiler(s);
- Alternative scenario 5: The electricity to be generated by project is provided by the other existing plants;
- Alternative scenario 6: The electricity to be generated by project is provided by the other new energy units,
- Alternative scenario 7: The electricity to be generated by project is provided by the other existing plants and the other new energy units.

These seven alternative scenarios are described below in more detail.

1) The proposed project not developed as a JI project

A combined cycle gas turbine unit with electricity capacity of 400 MW will be constructed at Shaturskaya TPP and commissioned in September 2010. Efficiency of new energy unit will be approximately 56%. Natural gas will be used as fuel. After project implementation electricity will be supplied by the new energy unit into grid of URES "Centre". It will replace electricity which otherwise will be generated at the other power plants of URES "Centre".

2) Construction of steam turbines of 400 MW in total with gas fired boiler(s)

Power unit(s), consisting of natural gas fired steam boiler(s) and steam turbines of 400 MW in total, will be constructed at Shaturskaya TPP. Natural gas will be used as fuel. Russian produced boiler(s) and steam turbines will be used. The power unit (s) will supply electricity into the grid of URES "Centre" that will replace electricity otherwise generated by the other power plants of regional system.

3) Construction of 400 MW steam turbines with coal fired boiler(s)

The power unit(s) consisting of coal fired boiler(s) and steam turbines of 400 MW in total will be constructed at Shaturskaya TPP. Currently this fuel type is being used at Shaturskaya TPP and a coal storage exists. Also the Russian produced boiler(s) and steam turbines will be used. The power unit (s) will supply electricity into the grid of URES "Centre" that will replace electricity otherwise generated by the other power plants of regional system.

4) Construction of steam turbines of 400 MW in total with peat fired boiler(s)

The power unit(s) consisting of peat fired boiler(s) and steam turbines of 400 MW in total will be constructed at Shaturskaya TPP. Currently this fuel type is used at Shaturskaya TPP and there is the peat storage. Also the domestic performed boiler(s) and steam turbines can be used. The power unit (s) will supply electricity into the grid of URES "Centre" that will replace electricity otherwise generated by the other power plants of regional system.

5) The electricity to be generated by project is provided by the other existing plants

OGK-4 does not install the new energy unit and project electricity generation would have to be covered by the other power plants within URES "Centre" that exists in the particular year that the project is generating electricity.



6) The electricity to be generated by project is provided by the other new energy units

OGK-4 does not install the new energy unit and project electricity generation will be covered by new energy units to be constructed by the other energy companies within URES "Centre".

7) The electricity to be generated by project is provided by the other existing plants and the other new energy units

OGK-4 does not install the new energy unit and project electricity generation would have to be covered by the other existing power plants and by the new energy units to be constructed by the other energy companies within URES "Centre". This alternative is a combination of alternative 5 and 6.

Sub-step 1b: Identification of the most plausible alternative scenario

Assessment of alternative scenario 1: The proposed project is not developed as a JI project

This project type is indicated as preferable for power plants on natural gas in "General Scheme of Power Facilities' Allocation by 2020" (General Scheme further in the text) approved by the Government of the Russian Federation (Order of February 22 2008 # 215p). The project has no technical barriers as natural gas is available, the technology as such has been implemented in many industrialized countries and electricity produced by the new energy unit can be supplied to the grid.

As is shown in Section B2 this project is not economically attractive. Therefore this alternative is a not the most plausible scenario.

Assessment of alternative scenario 2: Construction of steam turbines of 400 MW in total with gas fired boiler(s)

Investment cost of this project type is similar to CCGT⁵ but efficiency of electricity generation cycle is lower (about 39.5%⁶). This implies that more natural gas is consumed (approximately 50% more). Fuel cost accounts for 60-70% of the total operation cost and the operation cost in this case is 35% higher than for CCGT. Therefore this type of project is even less attractive than CCGT.

Also this project type is not indicated as preferable type project for power plants on natural gas located in the Central part of Russia in "General Scheme of Power Facilities' Allocation by 2020" approved by the Government of the Russian Federation.

Therefore this alternative scenario is not the most plausible scenario.

Assessment of alternative scenario 3: Construction of steam turbines of 400 MW in total with coal fired boiler(s)

This project type is indicated as preferable type of project only for power plants located in Siberia in "General Scheme of Power Facilities' Allocation by 2020" approved by the Government of the Russian Federation.

The major part of coal in Russia is being extracted in Siberia. Coal accounts for about 85% of the fuel balance of URES "Siberia". Coal price is almost the same as natural gas price for power plants in the

⁵ <http://www.e-apbe.ru/library/detail.php?ID=11106>

⁶ Annex I of "Tool to calculate the emission factor for an electricity system", version 01.1, Methodological Tool, CDM Executive board



European part of Russia. Usually efficiency of coal fired energy unit is about 39%⁷ (that is 16% lower than CCGT). The coal based best available technology for electricity (ultrasupercritical parameters of steam) has efficiency about 50%⁸ that is 6% less than efficiency of CCGT. So in any case coal based energy generation is less efficient than CCGT. In comparison with natural gas fired energy unit, coal fired energy unit requires additional equipment installation: systems of coal preparation and stack gases cleaning. Thus investment cost of this project type is approximately 1.5 times higher. Therefore this type of project is less attractive than CCGT.

Therefore this alternative is not the most plausible scenario.

Assessment of alternative scenario 4: Construction of steam turbines of 400 MW in total with peat fired boiler(s)

This alternative scenario the same as alternative scenario 3 in terms of efficiency, fuel price and investment cost required.

This alternative is not the most plausible scenario.

Assessment of alternative scenario 5: The electricity to be generated by project is provided by the other existing plants

Currently installed electricity capacity corresponds to the electricity market demand. But there are many old energy units in Russia. In accordance with CJSC “Agency of Energy Balances in the power industry” estimation approximately 10 GW of old capacities (life time expired several years ago) has to be dismantled by 2015 (3.9 GW by 2010). At the same time their forecast assumes the electricity demand growth will be 27.3 GW in 2012 in comparison with 2009⁹.

Therefore the existing power plants alone cannot cover the future electricity market demand and this alternative scenario is not reasonable and feasible.

Assessment of alternative scenario 6: The electricity to be generated by project is provided by the other new energy units

The existing power plants runtime factor of URES “Centre” varies from 0.28 to 0.68. The proper dispatching, network improvements and better energy unit operation (reduction of repair time, etc.) may result in better energy facilities performance thus increasing the net energy output of the existing plants.

Reconstruction of existing energy units can increase both the installed electrical capacity and the runtime factor. In accordance with CJSC “Agency of Energy Balances in the power industry” forecast the incremental (due to the renovation activities) installed capacity at the existing power plants will be approximately 2.3 GW by 2015¹⁰.

OJSC «System Operator of Unified Energy System» (JSC “SO of UES”) is in charge of the technical management of the demand and supply side of the energy market. It satisfies the demand by the most efficient way, both from an economic and technical point of view. As soon as more than 87% of the forecasted energy demand is to be provided by the existing energy plants it is unlikely that the system operator will ensure constant coverage of 0.4 GW (the project capacity) by new plants only.

⁷ Annex I of “Tool to calculate the emission factor for an electricity system”, version 01.1, Methodological Tool, CDM Executive board

⁸ Annex I of “Tool to calculate the emission factor for an electricity system”, version 01.1, Methodological Tool, CDM Executive board

⁹ <http://www.e-apbe.ru/library/detail.php?ID=11106>

¹⁰ <http://www.e-apbe.ru/library/detail.php?ID=11106>



It means that the electricity to be generated by project is to be provided by the existing power plants as well and therefore this alternative scenario is not reasonable and feasible.

Assessment of alternative scenario 7: The electricity to be generated by project is provided by the other existing plants and the other new energy units

As shown in the assessment of alternatives 5 and 6 the future electricity market demand would be covered by the combination of the other existing plants and the other new energy units.

Thus this alternative is reasonable and feasible.

Conclusion

Only Alternative 7 is realistic and credible and is selected as the baseline scenario.

Step 2: Additionality demonstration

Please see Section B.2.

Step 3: Calculation of emissions of the baseline scenario

To establish the emissions associated with the baseline scenario a multi-project emission factor has been calculated in accordance with article 19 of the Guidance. The baseline emissions are elaborated in Section D and Annex 2.

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:

According to paragraph 2 of Annex 1 of the Guidance, unless an approved CDM baseline and monitoring methodology is used, inter alia, the following options may be applied:

- Application of the most recent version of the “Tool for the demonstration and assessment of additionality” approved by the CDM Executive Board;
- Application of any other method for proving additionality approved by the CDM Executive Board;
- Provision of traceable and transparent information showing that the baseline was identified on the basis of conservative assumptions, that the project scenario is not part of the identified baseline scenario and that the project will lead to reductions of anthropogenic emissions by sources or enhancements of net anthropogenic removals by sinks of GHGs;
- Provision of traceable and transparent information that an accredited independent entity has already positively determined that a comparable project (to be) implemented under comparable circumstances (same GHG mitigation measure, same country, similar technology, similar scale) would result in a reduction of anthropogenic emissions by sources or an enhancement of net anthropogenic removals by sinks that is additional to any that would otherwise occur and a justification why this determination is relevant for the project at hand.

In this PDD, the most recent version of the “Tool for the demonstration and assessment of additionality” (version 05.2) (hereinafter referred to as “Additionality Tool”) is applied to prove that the emission reductions by the proposed JI project are additional to any that would otherwise occur.

Step 1: Identification of alternatives to the project consistent with current laws and regulations

Sub-step 1a: Define alternatives to the project

Plausible alternatives to the project were identified in Section B.1 above:

Alternative scenario 1: The proposed project is not developed as a JI project;

Alternative scenario 2: Construction steam turbines of 400 MW in total with gas fired boiler(s);

Alternative scenario 3: Construction of steam turbines of 400 MW in total with coal fired boiler(s);



- Alternative scenario 4: Construction of steam turbines of 400 MW in total with peat fired boiler(s);
- Alternative scenario 5: The electricity to be generated by project is provided by the other existing plants;
- Alternative scenario 6: The electricity to be generated by project is provided by the other new energy units,
- Alternative scenario 7: The electricity to be generated by project is provided by the other existing plants and the other new energy units.

Only alternatives 1 and 7 were identified as realistic and credible.

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

All the alternatives defined in sub-step 1a are in compliance with mandatory legislation and regulations.

Step 2: Investment analysis

The main goal of the investment analysis is to determine whether the proposed project is not:

- (a) The most economically or financially attractive; or
- (b) Economically or financially feasible, without the revenue from the sale of ERUs associated with the JI project.

To conduct the investment analysis, the following sub-steps have to be applied.

Sub-step 2a: Determine appropriate analysis method

In principle, there are three methods applicable for an investment analysis: simple cost analysis, investment comparison analysis and benchmark analysis.

A simple cost analysis (Option I) shall be applied if the proposed JI project and the alternatives identified in step 1 generate no financial or economic benefits other than JI related income. The proposed JI project results in additional sales revenues due to the electricity that will be generated. Thus, this analysis method is not applicable.

The Additionality Tool allows for an investment comparison analysis which compares suitable financial indicators for realistic and credible investment alternatives (Option II) or a benchmark analysis (Option III). For this project a benchmark analysis (Option III) is appropriate in accordance with the attached guidance to the Additionality Tool (paragraph 15).

Sub-step 2b: Option III. Apply benchmark analysis

The proposed project, installation of CCGT, shall be implemented by the project participant OGG-4. The approach recommended in p. 6 (a) of Additionality Tool is applied – using “government bonds rates increased by a suitable risk premium”. As Russia does not have long term governmental bonds a conservative approach of using Central Bank RF discount rate of 12% only is proposed in the analysis not including a risk premium. Thus the overall IRR benchmark amounts to 12%. If the proposed project (not being implemented as JI project) has a less favourable indicator, i.e. a lower IRR, than the benchmark, then the project cannot be considered as financially attractive.

Sub-step 2c: Calculation and comparison of financial indicators

The financial analysis refers to the time of investment decision-making.

The following assumptions have been used based on the information provided by the enterprise:

1. Investment decision: June 2007, commissioning date: 15 September 2010;
2. The project requires investments of approximately EUR 387 million during five years;



3. The calculations are made at constant prices as of June 2007¹¹;
4. The exchange rate (EUR/RUR) is rounded up to 1/34.71 in accordance with the enterprise's conversion practice;
5. The project lifetime is 25 years (lifetime of CCGT in line with GE documents);
6. The project does not foresee any replacement, so cash flows only for new capacities are considered;
7. Fuel consumption and electricity generation is taken into account in line with the technical specifications of the project design;
8. The annual installed capacity utilisation is 6,900 hours per year that corresponds to the run time factor of 0.79;
9. Natural gas is the biggest cost component constituting 75% of total operation cost.
10. Maintenance cost accounts for 18% of the total operation cost;
11. The scrap value is calculated as CCGT weight (documented) multiplied by scrap price;
12. Production is assumed at the maximum technical capacity.

The project cash flow focuses, in addition to investment-related outflows, on revenue flows generated by additional sales of electricity produced by the new CCGT.

The project's financial indicators are presented in the Table B.2.1 below.

Table B.2.1. Financial indicators of the project

Scenario	IRR (%)	Discounted PBP	Simple payback period (years) ¹²
Base case	1.80	Out of project lifetime	20

The cash flow analysis shows an IRR of 1.80%, which is well below the IRR benchmark identified of 12%. As a result a negative NPV¹³ is obtained. Hence, the project cannot be considered as financially attractive.

Sub-step 2d: Sensitivity analysis

A sensitivity analysis shall be conducted to show whether the conclusion regarding the financial/economic attractiveness is robust to reasonable variations in the critical assumptions.

The following four key factors were considered in the sensitivity analysis: electricity and gas tariffs, investment and maintenance cost. The other cost components account for much less than 20% of total cost and therefore are not considered in the sensitivity analysis. In line with the guidance to the Additionality Tool (par. 17) the sensitivity analysis should be undertaken within the corridor of $\pm 10\%$ for the key indicators.

Scenario 1 considers a 10% investment cost growth. Scenario 1 shows that this assumption worsened the cash flow performance due to significant cost increase.

Scenario 2 is based on the assumption of a 10% investment cost decrease that improves cash flow and performance indicators a little with IRR remaining below the benchmark.

¹¹ The calculation at constant prices as of the time of decision-making provides an objective view of the long-term future. It allows to perform a "pure" sensitivity analysis not impacted by expert estimations of inflation levels, prices etc., and to identify the most important factors really impacting the project's financial performance.

¹² The discounted payback period would be outside of the project lifetime.

¹³ Net present value

Scenario 3 implies electricity tariff raise 10%. The effect is similar to that described in Scenario 2.

Scenario 4 implies electricity tariff decrease 10%. That means that sales revenues drop worsening the cash flow performance.

Scenario 5 assumes 10% natural gas tariff growth. The result is similar to Scenario 1.

Scenario 6 assumes natural gas tariff decrease by 10%, increasing operation cost and decreasing the cash flow outcome.

Scenario 7 foresees 10% maintenance cost increase. The outcome is close to Scenario 1.

Scenario 8 has opposite assumption to Scenario 7. IRR improves but is still below benchmark.

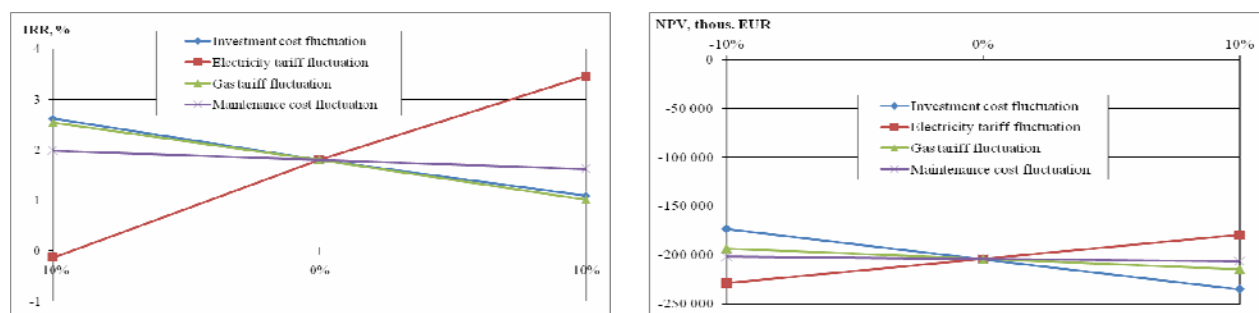
In all scenarios NPV is negative. The simple payback period is more than 12 years (the maximum Simple payback period accepted in energy generation sector) and discounted payback period exceeds project life time.

A summary of the results is presented in the Table B.2.2 and the Figures B.2.1 below.

Table B.2.2: Sensitivity analysis (summary)

Scenario	IRR (%)	Discounted PBP (years)	Simple payback period (years) ¹⁴
Scenario 1	1.09%	Out of project lifetime	22
Scenario 2	2.62%	Out of project lifetime	18
Scenario 3	3.46%	Out of project lifetime	17
Scenario 4	-0.13%	Out of project lifetime	Outside project lifetime
Scenario 5	1.02%	Out of project lifetime	22
Scenario 6	2.54%	Out of project lifetime	18
Scenario 7	1.62%	Out of project lifetime	20
Scenario 8	1.98%	Out of project lifetime	20

Figure B.2.1: IRR and NPV sensitivity analysis



¹⁴ The discounted payback periods would be outside of the project lifetime.

Hence, the sensitivity analysis consistently supports (for a realistic range of assumptions) the conclusion that the project is unlikely to be financially/economically attractive.

Step 3: Barrier analysis

In line with the Additionality Tool, a barrier analysis is not conducted.

Step 4: Common practice analysis

Sub-step 4a: Analyze other activities similar to the proposed project activity:

The project energy unit uses combined cycle (Rankine and Brayton (gas) thermodynamic cycles) for electricity generation (without heat generation). The installed capacity of this combine cycle gas turbine (CCGT) unit is 400MW.

In Russia almost all power plants use the Rankine (steam) cycle (fossil fuel fired boiler(s) with steam turbines). The total installed capacity of all CCGT units (including with cogeneration cycle) is about 2.6 GW (2007). It is approximately 1.7% of total thermal power plants installed capacity.

The Tool recommends to provide an analysis of any other activities if they are in the same country/region and rely on similar technology, are of a similar scale, and take place in the comparable environment.

The new energy units (of more than 50 MW having been installed during the last 16 years) are presented in the Table B.2.3.

Table B.2.3: New energy units (more 50MW) in Russia

Power plant/unit	Commissioning	Capacity, MW	Technology	Fuel	Cycle
URES "Centre"					
"Lutch" CHP	2005	60	CC GT	Gas	Cogeneration
Moscow CHP-27	2007	450	CC GT	Gas	Cogeneration
Moscow CHP-21	2008	450	CC GT	Gas	Cogeneration
Ivanovo Combined Cycle Plant	2007	325	CC GT	Gas	Combined cycle

The cogeneration energy units (including CCGT cogeneration units) generate and supply both heat and electricity. Heat is the most important product especially in cold climate while electricity is of secondary use. CCGT in the proposed project is being constructed to produce only electricity. Therefore CCGT units with cogeneration cycle are excluded from the analysis.

In line with the Tool's requirements only the Ivanovo Combined Cycle Plant (325 MW) can be considered as other activities similar to the proposed project activity.

The plant was constructed during the time that RAO UES as a monopolistic company still existed. It was the biggest energy company almost fully controlled by the state. This project was of the high priority as a pilot project to demonstrate the quality and applicability of gas turbines produced in Russia. The project was implemented due to the high political importance and thus can not be considered as project implemented in a common environment relevant for this common practise analysis.

Therefore there are no other activities similar to the proposed project activity. Hence, the proposed JI project is not common practice.

Sub-step 4b: Discuss any similar Options that are occurring:

The similar activities are not widely observed so this sub-step is not applicable.

Conclusion

The application of the CDM Additionality Tool demonstrates that the emission reductions by the proposed JI project are additional to any that would otherwise occur.

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

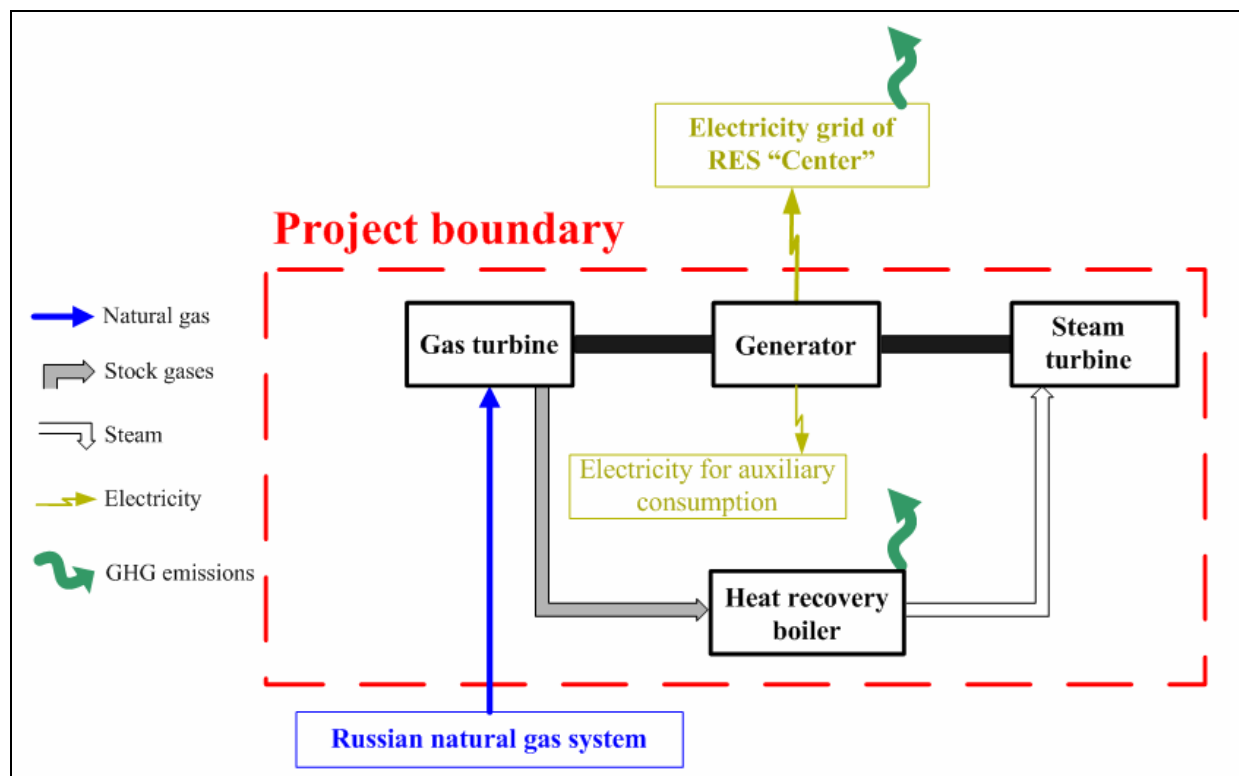
The new CCTG unit combusts natural gas for electricity generation, most of which is supplied to the grid and minor part is used for internal needs (auxiliary equipment).

Project boundary embraces:

- New CCTG unit;
- Auxiliary equipment of the new CCTG unit.

The project boundary is presented in Figure B.3.1.

Figure B.3.1: Project boundary



Emissions sources and greenhouse gases types included in or excluded from the project boundary are presented in the Table B.3.1.

**Table B.3.1: Emissions sources included or excluded from the project boundary**

No	Source	Gas	Included?	Justification/Explanation
Baseline	Electricity generation in baseline (URES "Centre")	CO ₂	Included	Main emission source
		CH ₄	Excluded	Excluding these emission from the baseline is conservative and in line with existing CDM methodologies ¹⁵
		N ₂ O	Excluded	
Project activity	On-site natural gas combustion	CO ₂	Included	Main emission source
		CH ₄	Excluded	Exclusions is for simplification as the emission are negligible and in line with existing CDM methodologies ¹⁶
		N ₂ O	Excluded	

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 baseline study: 09 October 2009

Name of person/entity setting the baseline:

Alexey Varfolomeev

E-mail: varfolomeev@global-carbon.com

¹⁵ Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas, AM0029/version 03, Approved Methodology, CDM Executive board

¹⁶ Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas, AM0029/version 03, Approved Methodology, CDM Executive board

**SECTION C. Duration of the project / crediting period****C.1. Starting date of the project:**

Starting date of the project is 15/09/2010.

C.2. Expected operational lifetime of the project:

The operational lifetime of the proposed JI project is 30 years or 360 months.

C.3. Length of the crediting period:

For the period from 15 September 2010 until 31 December 2012 carbon credits will be transferred in line with Article 6 of the Kyoto Protocol (JI). Thus the length of the crediting period will be two full years and 3.5 months or 27.5 months.

Start of crediting period: 15/09/2009.

Length of crediting period within Kyoto commitment period: two years and 3.5 months or 27.5 months.

Length of crediting period within any relevant agreement under the UNFCCC from 2013 onwards: The length of the second commitment period where 2013 – 2020 (8 years is assumed).

**SECTION D. Monitoring plan****D.1. Description of monitoring plan chosen:**

In this project JI specific approach regarding monitoring is used. As elaborated in Section B.3, the project activity only affects the emissions related to the natural gas combustion. To establish the baseline emissions and to monitor the project emissions, only these emissions will be monitored.

The following assumptions for calculation of both baseline and project emissions were used:

- Used start-up fuel at the new CCGT unit is excluded¹⁷;
- Project electricity is net electricity generation by the new CCGT unit defined as electricity generation minus electricity consumption for internal needs;
- Electricity demand in the market is not influenced by the project (i.e. baseline net electricity generation = project net electricity generation);
- The baseline emissions of the grid are established using the combined margin emission factor as described in Annex 2;
- Combined margin emission factor is set ex-ante for the length of the crediting period;
- The new CCGT lifetime extends to 2020.

General remarks:

- Social indicators such as number of people employed, safety records, training records, etc, will be available to the Verifier if required;
- Environmental indicators such as NO_x and other will be available to the Verifier if required;

For the greenhouse gas emissions only the CO₂ emissions are taken into account. See section B.3.

¹⁷ Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas, AM0029/version 03, Approved Methodology, CDM Executive board

**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
P1 PE_y	Project emission	Calculated under project activity	tCO ₂	c	Annually	100%	Electronic	Defined according to formula 1
P2 $FC_{NG,y}$	Annual quantity of natural gas consumed in project activity	Fuel flow meter reading	m ³	m	Continuously	100%	Electronic	-
P3 $COEF_y$	CO ₂ emission coefficient	Calculated under project activity	tCO ₂ /m ³	c	Annually	100%	Electronic	Defined according to formula 2
P4 $NCV_{NG,y}$	Net Calorific Value of natural gas	Local estimated/fuel supplier/IPCC	GJ/m ³	e	Continuously/daily/monthly	100%	Electronic	Chromatographic gas analyzer estimates <i>NCV</i> of natural gas continuously, in other cases the on-site chemical-analysis laboratory data/fuel supplier provided data/IPCC default value can be used (that order of preference)
P5 $EF_{CO_2,NG,y}$	Emission factor for natural gas	IPCC	tCO ₂ /GJ	e	Annually	100%	Electronic	IPCC default value (2006)

**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
								IPCC Guidelines on National GHG Inventories, Vol.2, Chapter 1)

D.1.1.2. Description of formulae used to estimate project emissions (for each gas, source etc.; emissions in units of CO₂ equivalent):

The project activity is combustion of natural gas to generate electricity at the new CCGT unit. The CO₂ emissions from electricity generation (PE_y) are calculated as follows:

$$PE_y = FC_{NG,y} \times COEF_{NG,y} \quad (1)$$

Where:

PE_y Project emission in year y (tCO₂);

$FC_{NG,y}$ Is the total volume of natural gas combusted at the new CCGT unit in year y (m³);

$COEF_y$ Is the CO₂ emission coefficient in year y (tCO₂/m³ or similar).

$COEF_y$ is obtained as:

$$COEF_y = NCV_{NG,y} \times EF_{CO_2,NG,y} \quad (2)$$

Where:

$NCV_{NG,y}$ Is the net calorific value per volume unit of natural gas in the year y (GJ/m³);



$EF_{CO_2,NG,y}$ Is the CO₂ emission factor per unit of energy of natural gas in year y (tCO₂/GJ).

D.1.1.3. Relevant data necessary for determining the <u>baseline</u> of anthropogenic emissions of greenhouse gases by sources within the project boundary, and how such data will be collected and archived:								
ID number (Please use numbers to ease cross-referencing to D.2.)	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
B1 BE_y	Baseline emissions	Calculated under project activity	tCO ₂	c	Annually	100%	Electronic	Defined according to formula 3
B2 $EG_{PJ,y}$	Net quantity of electricity generated at the new CCGT unit	Calculated under project activity	MWh	c	Annually	100%	Electronic	Defined according to formula 4
B3 $EF_{BL,CO_2,y}$	Baseline emission factor	Annex 2 of PDD	tCO ₂ /MWh	c	Fixed ex ante	100%	Electronic	Combine margin emission factor of United Regional Electricity System "Centre". See Annex 2.
B4 $EG_{PJ,GEN,y}$	Quantity of electricity generated at the new CCGT unit	Electricity meter reading	MWh	m	Continuously	100%	Electronic	-
B5 $EG_{PJ,AUX,y}$	Quantity of electricity for the new CCGT unit internal needs	Electricity meters reading	MWh	m	Continuously	100%	Electronic	-

D.1.1.4. Description of formulae used to estimate baseline emissions (for each gas, source etc.; emissions in units of CO₂ equivalent):

The baseline emission is defined as:

$$BE_y = EG_{PJ,y} \times EF_{BL,CO_2,y} \quad (3)$$



Where:

- BE_y Are the baseline emissions in the year y (tCO₂);
- $EG_{PJ,y}$ Is the net quantity of electricity generated at the new CCGT unit in the year y (MWh);
- $EF_{BL,CO_2,y}$ Is the baseline emission factor in year y (tCO₂/MWh). It is an ex-ante fixed value, see Annex 2.

The net quantity of electricity generated at the new CCGT unit is defined as:

$$EG_{PJ,y} = EG_{PJ,GEN,y} - EG_{PJ,AUX,y} \quad (4)$$

Where:

- $EG_{PJ,GEN,y}$ Is the quantity of electricity generated at the new CCGT unit in the year y (MWh);
- $EG_{PJ,AUX,y}$ Is the quantity of electricity for the new CCGT unit internal needs (auxiliary equipment) in the year y (MWh).

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

Not applicable.

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

Not applicable.

D.1.2.2. Description of formulae used to calculate emission reductions from the project (for each gas, source etc.; emissions/emission reductions in units of CO₂ equivalent):

Not applicable.

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

There are fugitive CH₄ emissions associated with fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of natural gas used in the project plant and fossil fuels in the grid in the absence of the project¹⁸. These emissions have not been taken into account for simplicity and conservatism.

¹⁸ Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas, AM0029/version 03, Approved Methodology, CDM Executive board

**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:**

Not applicable.

D.1.3.2. Description of formulae used to estimate leakage (for each gas, source etc.; emissions in units of CO₂ equivalent):

Not applicable.

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 CO₂ equivalent):

$$ER_y = BE_y - PE_y \quad (29)$$

Where:

 ER_y JI project emission reduction in year y (tCO₂); BE_y Baseline emissions in year y (tCO₂); PE_y Project emissions in year y (tCO₂).**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:**

Emissions into the air are the only important source of pollution at Shaturuskaya TPP which have a negative impact on the local environment. According to national requirements, atmospheric emissions have to be measured by making samples once a year or five years. This requirement is described in the section "Environment Protection" of "Project Design"¹⁹ that was approved by the Federal Governmental Body "The Main Agency of the State Expertise" (FGU "Glavgosexpertiza" in Russian abbreviation). Shaturuskaya TPP systematically collects pollution data that may have negative impact on the local environment. Air pollution monitoring is made by accredited laboratory of Shaturuskaya TPP, local environmental organizations and Central State Organization of Environmental Supervision. The list pollutants monitored is presented in the Table D.1.5.1.

¹⁹ "Creating the Replacing Capacity by CCGT-400 Installation at Shaturuskaya TPP, OGGK-4" Project Design, Volume 12: Environment Protection, OJSC "Engineer Centre of UES", 2008

*Table D.1.5.1: Monitored pollutants*

N	Monitored pollutants	Monitoring frequency	Monitoring method
1	Nitrogen dioxide	twice a year	by gas analyzer
2	Nitrogen oxides	twice a year	by gas analyzer
3	Carbon oxide	twice a year	by gas analyzer

Source: Data provided by OGK-4.

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.
P2	Low	In accordance with State Standard the allowed inaccuracy of gas consumption metering is $\pm 0.3-4\%$ (GOST R 8.618-2006). The inaccuracy of flow gas meter to be installed is $\pm 0.5\%$. This type of meter is included in State list of measuring devices.
P4	Low	Natural gas NCV is measured by chromatographic gas analyzer. It is included in State list of measuring devices. In other cases the on-site chemical-analysis laboratory (CAL) can measure the NCV. The CAL has necessary licenses and is accredited to System of analytic laboratories accreditation (N ROSS RU.0001.516795).
B4	Low	The electricity generated at the new CCGT unit and electricity for the new CCGT unit internal needs are determined by standardized electricity meters. This data is automatically inserted into the electronic data base.
B5	Low	

The data from meters on indicators P2, P4, B4 and B5 is automatically and regularly transferred to the Shaturskaya TPP server. This data is further being processed by the Production and Technical Department which prepares the monitoring report and keeps archives.

The plant's Department of the Control and Measuring devices is in charge of the efficient supervision of measuring devices operation and performance. It checks and substitutes devices (adjusted and calibrated) from spare parts if necessary.



Calibration of the metering devices is made in accordance with the calibration schedule. It is approved by the Chief Engineer of Shaturskaya TPP every year. The metering devices are calibrated by the independent entity which has a state licence.

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

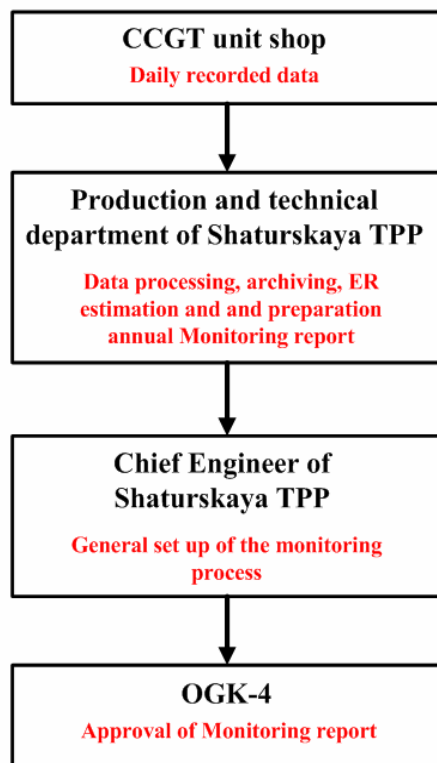
Division of responsibilities for Monitoring Plan implementation and Monitoring Report preparation is presented in the Table D.3.1.

Table D.3.1: Division of responsibilities for Monitoring Plan implementation and Monitoring Report preparation

N	Responsible	Task
1	Shaturskaya TPP: <ul style="list-style-type: none"> • Department of the control and measuring devices; • CCGT unit shop; • Production and technical department; • Chief Engineer 	Quality control of measuring devices; Daily recorded data; Collection, data processing, archived, ER estimation and preparation annual Monitoring report; General organization of the monitoring process.
2	OGK-4	Preparation and approval of monitoring process internal regulations; Approval of Monitoring report; General supervision.
3	Global Carbon BV	Staff training on monitoring procedures and reporting

The scheme of the operational and management structure in implementing the monitoring plan is presented in Figure D.3.1.

Figure D.3.1: The organisational structure of the Monitoring plan implementation



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

- OJSC “OGK-4”, Mr Egor Vasilkonov, specialist of production and technical department
E-mail: vec@ogk-4.ru
- Global Carbon BV, Mr Alexey Varfolomeev, Engineer
E-mail: varfolomeev@global-carbon.com

**SECTION E. Estimation of greenhouse gas emission reductions****E.1. Estimated project emissions:***Table E.1.1: Estimated project emissions within the crediting period*

Indicator	Unit	2010	2011	2012
Annual natural gas consumption	thous.m ³	147,064	490,214	490,214
Net calorific value of natural gas	GJ/thous.m ³	35.94	35.94	35.94
Emission factor of natural gas	tCO ₂ /GJ	0.056	0.056	0.056
Project emission	tCO ₂	296,504	988,348	988,348
Total 2010 - 2012	tCO ₂	2,273,199		

Table E.1.2: Estimated emissions after the crediting period

Indicator	Unit	2013	2014	2015	2016	2017	2018	2019	2020
Annual natural gas consumption	thous.m ³	490,214	490,214	490,214	490,214	490,214	490,214	490,214	490,214
Net calorific value of natural gas	GJ/thous.m ³	35.94	35.94	35.94	35.94	35.94	35.94	35.94	35.94
Emission factor of natural gas	tCO ₂ /GJ	0.056	0.056	0.056	0.056	0.056	0.056	0.056	0.056
Project emission	tCO ₂	988,348	988,348	988,348	988,348	988,348	988,348	988,348	988,348
Total 2013 - 2020	tCO ₂	7,906,780							

E.2. Estimated leakage:

Not applicable.

E.3. The sum of E.1. and E.2.:*Table E.3.1: Estimated project emissions inclusive leakage within the crediting period*

Indicator	Unit	2010	2011	2012
Annual natural gas consumption	thous.m ³	147,064	490,214	490,214
Net calorific value of natural gas	GJ/thous.m ³	35.94	35.94	35.94
Emission factor of natural gas	tCO ₂ /GJ	0.056	0.056	0.056
Project emission	tCO ₂	296,504	988,348	988,348
Total 2010 - 2012	tCO ₂	2,273,199		

**Table E.3.2: Estimated project emissions inclusive leakage after the crediting period**

Indicator	Unit	2013	2014	2015	2016	2017	2018	2019	2020
Annual natural gas consumption	thous.m ³	490,214	490,214	490,214	490,214	490,214	490,214	490,214	490,214
Net calorific value of natural gas	GJ/thous.m ³	35.94	35.94	35.94	35.94	35.94	35.94	35.94	35.94
Emission factor of natural gas	tCO ₂ /GJ	0.056	0.056	0.056	0.056	0.056	0.056	0.056	0.056
Project emission	tCO ₂	988,348	988,348	988,348	988,348	988,348	988,348	988,348	988,348
Total 2013 - 2020	tCO ₂	7,906,780							

E.4. Estimated baseline emissions:**Table E.4.1: Estimated baseline emissions within the crediting period**

Indicator	Unit	2010	2011	2012
Annual electricity output	MWh	821,086	2,736,954	2,736,954
Electricity EF of URES "Centre"	tCO ₂ /MWh	0.540	0.540	0.540
Baseline emission	tCO ₂	443,755	1,479,184	1,479,184
Total 2010 - 2012	tCO ₂	3,402,124		

Table E.4.2: Estimated baseline emissions after the crediting period

Indicator	Unit	2013	2014	2015	2016	2017	2018	2019	2020
Annual electricity output	MWh	2,736,954	2,736,954	2,736,954	2,736,954	2,736,954	2,736,954	2,736,954	2,736,954
Electricity EF of URES "Centre"	tCO ₂ /MWh	0.540	0.540	0.540	0.540	0.540	0.540	0.540	0.540
Baseline emission	tCO ₂	1,479,184	1,479,184	1,479,184	1,479,184	1,479,184	1,479,184	1,479,184	1,479,184
Total 2013 - 2020	tCO ₂	11,833,473							

E.5. Difference between E.4. and E.3. representing the emission reductions of the project:**Table E.5.1: Difference representing the emission reductions within the crediting period**

Reductions	Unit	2010	2011	2012
Total	tCO ₂	147,251	490,837	490,837
Total 2010 - 2012	tCO ₂	1,128,924		

Table E.5.2: Difference representing the emission reductions after the crediting period

Reductions	Unit	2013	2014	2015	2016	2017	2018	2019	2020
Total	tCO ₂	490,837	490,837	490,837	490,837	490,837	490,837	490,837	490,837
Total 2013 - 2020	tCO ₂	3,926,693							

**E.6. Table providing values obtained when applying formulae above:***Table E.6.1: Project, baseline, and emission reductions within the crediting period*

Year	Estimated <u>project</u> emissions (tonnes of CO ₂ equivalent)	Estimated <u>leakage</u> (tonnes of CO ₂ equivalent)	Estimated <u>baseline</u> emissions (tonnes of CO ₂ equivalent)	Estimated emission reductions (tonnes of CO ₂ equivalent)
Year 2010	296,504	0	443,755	147,251
Year 2011	988,348	0	1,479,184	490,837
Year 2012	988,348	0	1,479,184	490,837
Total (tonnes of CO ₂ equivalent)	2,273,199	0	3,402,124	1,128,924

Table E.6.2: Project, baseline, and emission reductions after the crediting period

Year	Estimated <u>project</u> emissions (tonnes of CO ₂ equivalent)	Estimated <u>leakage</u> (tonnes of CO ₂ equivalent)	Estimated <u>baseline</u> emissions (tonnes of CO ₂ equivalent)	Estimated emission reductions (tonnes of CO ₂ equivalent)
Year 2013	988,348	0	1,479,184	490,837
Year 2014	988,348	0	1,479,184	490,837
Year 2015	988,348	0	1,479,184	490,837
Year 2016	988,348	0	1,479,184	490,837
Year 2017	988,348	0	1,479,184	490,837
Year 2018	988,348	0	1,479,184	490,837
Year 2019	988,348	0	1,479,184	490,837
Year 2020	988,348	0	1,479,184	490,837
Total (tonnes of CO ₂ equivalent)	7,906,780	0	11,833,473	3,926,693

**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 necessity of an Environmental Impact Assessment (EIA) in Russia is regulated by the Federal Law “On the Environmental Expertise” and consists of two stages: EIA (OVOS –in Russian abbreviation) and state environmental expertise (SEE). Significant changes into this procedure have been made by the Law on Amendments to the Construction Code which came into force on the 1st of January 2007. This Law reduced the scope of activities subject to SEE transferring them to the so called State Expertise (SE) done in line with the Article 49 of the Construction Code of the Russian Federation. In line with the Construction code the Design Document should contain the Section “Environment Protection”. Compliance with the environmental regulations (so called technical regulation in Russian on Environmental Safety) should be checked during the process of SE.

Thermal power plants with capacities of 150 MW and higher are considered to be dangerous, technical complicated and unique facilities in line with the Article 48.1 of the Construction Code RF. Design Document of such installations are subject to the state expertise at federal level. Thus OGK-4 submitted a Design Document for this project to the Federal State Institution “The Main Agency of the State expertise” (FGU “Glavgosexpertiza” in Russian abbreviation) in June 2008 and received an approval in November 2008.

Currently CCGT is the most environmentally sound electricity generation technology. The main pollutants are nitrogen oxides and carbon oxide.

Calculation of air pollution is made by program complex UPRZA “Ekolog“, version 3.0. The main pollutants emissions are presented in the Table F.1.1

Table F.1.1: Overview of non-GHG emissions

Code of Pollutant	Pollution	Before project	After project
		Amount, tonnes per year	
301	Nitrogen dioxide	11,856.9	12,664.2
304	Nitrogen oxide	1,925.9	2,057.1
337	Carbon oxide	13.9	393.4

Source: Data provided by OGK-4

Calculation analysis of pollutions dispersion shows that all emissions are within the maximum allowable concentrations.

The main conclusions of the section “Environmental Protection” of the Design Document (Environmental Protection) for this project and Expert Conclusion by FGU “Glavgosexpertiza” are presented below (Expert Conclusion).

Air protection:

“... after project implementation the maximum allowable concentrations will not be changed...”.

Noise pollution:

“... will be ensured within the required noise level limits regulated by the Sanitary regulation...”.

***Water protection:***

“... TPP water discharge will insignificantly impact some types of phytoplankton and will not influence zooplankton...”.

Hazardous waste (No hazardous waste will be generated by the project).

Labour safety and welfare of inhabitants:

“Concerning the project decisions and the arrangements for the guaranteeing of sanitary-and-epidemiologic welfare of inhabitants and TPP staff, the project complies with the requirements of the Sanitary and Epidemiologic Rules and Guidance...”.

The main conclusion:

“The proposed project complies with the environment protection requirements of the Russian Federation”.

Thus project impact is considered insignificant.

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:

Not applicable

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

OGK-4 prepared reports “Corporate Stability and Social Responsibility” in 2005, 2006 and 2007. These reports contain information about proposed project. Representatives of environmental organizations, state and local authorities, mass media attended the public hearings (http://www.ogk-4.ru/?obj=res_otch).

Project information was published on the OGK-4 website:

- <http://www.ogk-4.ru/?obj=news1>;
- <http://www.ogk-4.ru/?obj=id4894&id=5161>

OGK-4 had publications about the project in mass media. The short list of publications is presented below.

- “World Energy”: E.ON starts the new energy unit installation at Shaturskaya TPP;
- Energyland.info: The turbine is to be installed at Shaturskaya TPP;
- Oilru.com: E.ON starts the new energy unit installation at Shaturskaya TPP.

Annex 1**CONTACT INFORMATION ON PROJECT PARTICIPANTS**

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Annex 2**BASELINE INFORMATION****CO₂ baseline emission factor**

The purpose of the baseline emission factor study presented below is to establish a multi-project emission factor for the electricity grid in accordance with the “Guidance on Criteria for baseline setting and monitoring” where article 10 (b) (i) states that “A baseline shall be established on a project-specific basis and/or using a multi-project emission factor”. This multi-project emission factor was defined in accordance with approved CDM “Tool to calculate the emission factor for an electricity system” (version 01.1), further referred as “The Tool”.

The full version of the Tool is published on the UNFCCC website under the following address: <http://cdm.unfccc.int/methodologies/PAmethodologies/approved.html>.

Scope and applicability

This Tool “...determines the CO₂ emission factor ... for the purpose of calculating baseline emissions for a project activity substitutes electricity from the grid, i.e. where a project activity supplies electricity to a grid...”.

Combined cycle gas turbine unit with electricity capacity of 400 MW will be constructed at Shaturuskaya TPP and commissioned in September 2010. After project implementation the new electricity energy unit will supply electricity to grid of United Regional Energy System (URES) “Centre”. It will replace electricity that would have been otherwise generated by the other power plants of URES “Centre”. Therefore this Tool can be used for determination of CO₂ baseline emission factor.

Parameters

The Tool provides procedures to determine the following parameters:

Parameter	SI Unit	Description
EF _{grid,CM,y}	tCO ₂ /MWh	Combined margin CO ₂ emission factor for grid connected power generation in year y
EF _{grid,BM,y}	tCO ₂ /MWh	Build margin CO ₂ emission factor for grid connected power generation in year y
EF _{grid,OM,y}	tCO ₂ /MWh	Operating margin CO ₂ emission factor for grid connected power generation in year y

Data source

The following sources of information were used for the OM development:

- Federal Service of State Statistics (Rosstat RF). This is aggregated data provided by energy companies using the official statistical form 6-TP;
- JSC “Unified Energy System of Russia” (UES);
- OJSC «System Operator of Unified Energy System» (JSC “SO of UES”);
- CJSC “Agency of Energy Balances in the power industry”.

BM calculation is based on the data from:

- Official annual reports of JSC UES;
- Reports containing information on new power capacities put in operation in recent years, “General Scheme of Power Facilities’ Allocation by 2020” approved by the Government of the Russian Federation (Order of February 22 2008 # 215p);
- Energy companies investment programs.



This data is relevant and sufficient for emission factors calculation in accordance with the Tool.

Methodology procedure

The Tool determines CO₂ emission factor for an electricity, generated by power plants, displacement in an electricity system, by calculating the “operating margin” (OM) and “build margin” (BM) as well as the “combined margin” (CM). Operating margin refers to a cohort of power plants that reflects the existing power plants whose electricity generation would be affected by the proposed project activity. Build margin refers to a cohort of power units that reflect the type of power units whose construction would be affected by the proposed project activity.

In line with the Tool the following steps presented in detail below should be followed. Possible deviations should be identified and justified.

STEP 1: Identify the relevant electric power system

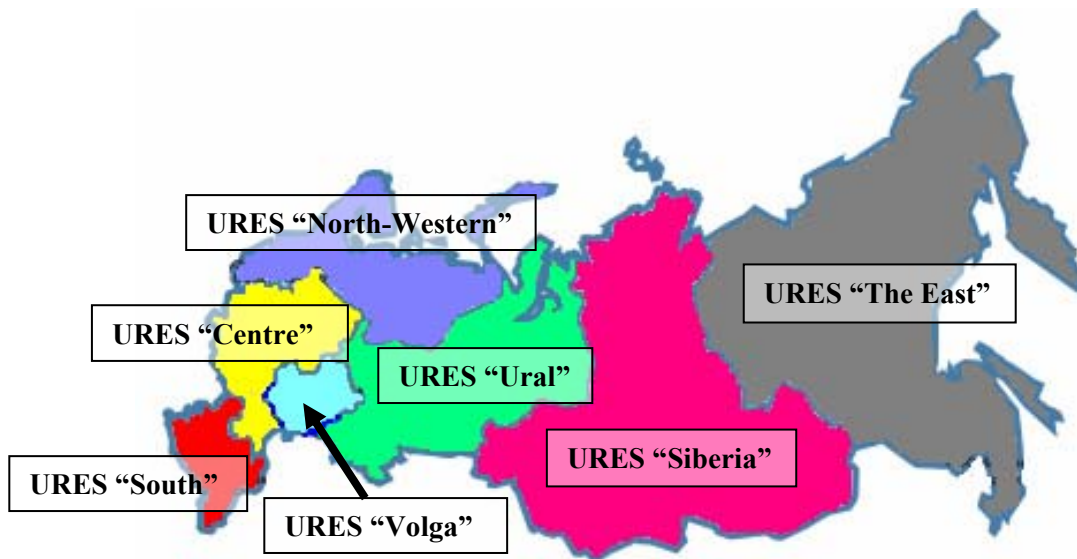
A project electricity system is the system defined by the spatial extent of the power plants that are physically connected through transmission and distribution lines to the project activity and that can be dispatched without significant transmission constraints. Similarly, a connected electricity system is defined as a system that is connected by transmission lines to the project electricity system. Power plants within connected system can be dispatched without significant transmission constraints but transmission to the project electricity system has significant transmission constraint.

If the Designated National Authority of the host country (in Russia it is the Ministry of Economic Development RF) has published a delineation of the project electricity system and connected power systems, these delineations should be used. The Designated Focal Point (DFP) of the Russian Federation has not published a delineation of the project electricity system and connected electricity systems. Therefore the recommendation of the Tool is applied: “... to use a regional grid definition in case of large countries with layered dispatch systems (e.g. provincial / regional / national)”.

Electric power industry in Russian Federation comprises nearly 400 power plants: thermal power plants (about 70% of total installed capacity), hydro power stations (20% of total installed capacity) and nuclear power stations (10% of total installed capacity). Power stations and consumers are connected by transmission lines. Power stations, consumers and regulatory organizations (JSC “SO of UES” for instance) constitute the national energy system (hereinafter referred to as UES of Russia). The UES of Russia is functioning centralized. JSC “SO of UES” contributes a great value to the operative-dispatching management.

Power stations are unified by transmission lines in 60 area electricity systems (AESs), while these systems have in its turn the electric connections with the neighbouring ones (excluding some isolated area systems). AESs are unified in seven united regional systems (URESs), that are connected between each other through backbone and interconnection networks: “North-Western”, “Centre”, “South”, “Volga”, “Ural”, “Siberia” and “The East”. The scheme of UES of Russia is presented in Figure Anx.2.1.

Figure Anx.2.1: Scheme of UES of Russia



Source: JSC "SO of UES"

URES "East" is the isolated system and URES "Siberia" is the semi-isolated system. Other systems are independent of other. Annual import/export of electricity between URESs is less than 1% (excluding from URES "Volga" to URES "South" and URES "Ural" – about 6%).

Shaturuskaya TPP is located in URES "Centre". Installed capacity of this URES is 48,257 MW (status 2009). It is the largest unified power system in UES of Russia. Power plants located at the Moscow-city territories, areas of Yaroslavl, Tver, Smolensk, Moscow, Ivanovo, Vladimir, Vologda, Kostroma, Nizhegorodskaya, Ryazan, Tambov, Bryansk, Kaluga, Tula, Orel, Kursk, Belgorod, Voronezh and Lipetsk constitute about 25% from the total generating capacity of UES of Russia.

The structure of installed capacity of URES "Centre" is as follows:

- 63% – TPPs ;
- about 30% – Nuclear power stations (NPSs);
- about 6% – Hydro power stations (HPSs);
- Other capacities based on wind, geothermal, solar, low-cost biomass, etc. are negligible for the URES power balance.

NPS operate as "must-run" resources and HPSs – as "low-cost".

Thus URES "Centre" is the project electricity system. As is shown in Section B.1 the annual import/export of electricity between URES "Centre" and other URESs (connected electricity system) is less than 1%. It means that URES "Centre" can be considered as independent system.

Project capacity (400 MW) is only 0.8% of the URES "Centre" total electric capacity, therefore project capacity "...can be dispatched without significant transmission constraints"²⁰.

²⁰ Tool to calculate the emission factor for an electricity system, version 01.1, Methodological Tool, CDM Executive board

As a result URES “Centre” is selected as a relevant electric power system.

STEP 2: Select an operating margin (OM) method

The Tool recommends to calculate the $EF_{grid,OM,y}$ based on one of the following methods:

- (a) Simple OM, or
- (b) Simple adjusted OM, or
- (c) Dispatch data analysis, or
- (d) Average OM.

Any of these listed methods can be used, however, the simple OM method (a) can only be used if low-cost/must run resources constitute less than 50% of total grid generation calculated:

- 1) As average of the five most recent years or,
- 2) Based on long-term averages for hydroelectricity production.

Low-cost/must run resources are defined as power plants with low marginal generation costs or that are dispatched independently of the daily or seasonal load of the grid. Typically they include hydro, geothermal, wind, low-cost biomass, nuclear and solar generation. In URES “Centre” geothermal, wind, low-cost biomass, and solar generation are negligible for the power balance. Therefore only nuclear stations (as “must-run”) and hydro plants (as “low-cost”) are defined as low-cost/must run resources. Table Anx.2.1 represents” total electricity generation during the five last years and the five year average share of low-cost/must run resources in URES “Centre (2003-2007).

Table Anx.2.1: Share of RES’s low-cost/must run net electricity generation (MWh)

URES “Centre”	2003	2004	2005	2006	2007	Five year average % of low-cost
All power plants	184,370,790	193,147,189	205,325,854	227,146,629	228,827,872	36.0
hydro	3,979,581	3,581,856	2,907,517	5,061,950	5,195,890	
nuclear	62,223,173	67,458,244	73,201,563	75,853,726	74,669,245	

Source: JSC “SO of UES” and Rosstat RF

As this indicator is lower than 50% the nuclear and hydro energy generation may not be taken into account. Therefore simple OM (method “a”) can be used and is selected for calculation of emission factor of URES “Centre”.

STEP 3: Calculate $EF_{grid,OM,y}$ according to the selected method

The Tool specifies how simple OM is calculated - as the generation-weighted average CO₂ emissions per unit net electricity generation (tCO₂/MWh) of all generating power plants serving the system, not including low-cost/must run plants/units (e.g. hydro and nuclear).

The Tool suggests making calculations based on:

- Data on fuel consumption and net electricity generation of each power plant/unit (Option A);
- Data on net electricity generation, the average efficiency of each power unit and fuel type used in each power unit (Option B);
- Data on total net electricity generation of all power plants serving the system and the fuel types and total fuel consumption of the project electricity system (Option C).

As soon as in the Russian Federation individual plant based data is considered strictly confidential the official statistical format 6–TP aggregates the data on the regional basis. This is the only data source publicly available for emission factor calculation. Thus only Option C is feasible.

Where the simple operating margin is defined by the following formula:

$$EF_{grig, OMsimple, y} = \frac{\sum_i FC_{i,y} \times NCV_{i,y} \times EF_{CO_2,i,y}}{EG_y} \quad (1)$$

Where:

- $EF_{grig, OMsimple, y}$ – simple operating margin CO₂ emission factor in year y (tCO₂/MWh);
- $FC_{i,my}$ – amount of fossil fuel *i* consumed in the project electricity system 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);
- $EF_{CO_2,i,y}$ – CO₂ emission factor of fossil fuel type *i* in year y (tCO₂/GJ);
- $EG_{m,y}$ – net electricity generated and delivered to the grid by all power sources serving the system, not including low-cost/must-run power plants/units, in year y (MWh);
- i* – all fossil fuel types combusted in power plants in the project electricity system in year y;
- y* – the three most recent years for which data is available (2006-2008).

The net electricity generation and fossil fuels consumed in the project electricity system are received from Rosstat RF. The amount of fossil fuels are expressed in tonne of coal equivalent with net calorific value is equal to 7,000 kcal/kg c.e. or 29.33 GJ/t c.e.

The net electricity generation and fuel consumption data at the TPPs of URES “Centre” in 2006-2008 are presented in the Table Anx.2.2.

Table Anx.2.2: The net electricity generation and fuel consumption data

Indicator	Unit	2006	2007	2008
Net electricity generation	MWh	129,216,774	146,230,953	148,962,737
Natural gas	t.c.e	36,764,206	42,757,580	42,941,363
	GJ	1,078,294,152	1,254,079,816	1,259,470,180
Heavy fuel oil	t.c.e	1,271,359	480,474	534,282
	GJ	37,288,955	14,092,297	15,670,500
Coal	t.c.e	2,934,364	4,025,757	3,200,880
	GJ	86,064,898	118,075,457	93,881,816
Peat	t.c.e	157,367	152,049	114,689
	GJ	4,615,585	4,459,598	3,363,841
Other	t.c.e	41,168	25,165	1,164,935
	GJ	1,207,466	738,077	34,167,539

Source: Rosstat RF

The default fuel emission factors are presented in the Table Anx.2.3.

Table Anx.2.3: The default fuel emission factors

Fuel type	Default emission factor ²¹
	tCO ₂ /GJ
Natural gas	0.056
Heavy fuel oil	0.077
Coal	0.096
Peat	0.106
Other fuel types ²²	0.0

The results of CO₂ emissions calculation at the TPPs of URES “Centre” in 2006-2008 are presented in the Table Anx.2.4.

Table Anx.2.4: Results of CO₂ emissions calculation

Indicator	Unit	2006	2007	2008
Natural gas	tCO ₂	60,492,302	70,353,878	70,656,277
Heavy fuel oil	tCO ₂	2,886,165	1,090,744	1,212,897
Coal	tCO ₂	8,270,837	11,347,051	9,022,043
Peat	tCO ₂	489,252	472,717	356,567
Total	tCO₂	72,138,556	83,264,390	81,247,783

The results of $EF_{grig, OMsimple, y}$ and the average electricity weighted OM emission factor calculation are presented in the Table Anx.2.5.

Table Anx.2.5: Results of $EF_{grig, BM, y}$ and the average electricity weighted OM emission factor calculation

Indicator	Unit	2006	2007	2008
OM emission factor	tCO ₂ /MWh	0.558	0.569	0.545
Average electricity weighted OM emission factor	tCO₂/MWh	0.558		

OM emission factor is ex-ante for period 2008-2012.

STEP 4: Identify the cohort of power units to be included in the BM

The Tool provides the recommendations on how to form the sample groups of power units used to calculate the BM. They consist of either:

- The set of five power units that have been built most recently, or
- 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.

²¹ Guidelines for National Greenhouse Gas Inventories, Volume 2: Energy, Chapter 2: Stationary Combustion (corrected chapter as of April 2007), IPCC, 2006

²² Emission factor for other types of fuel is taken as zero. It is conservative

If the recommended approach does not reasonably reflect the power plants that would likely be built in the absence of the project activity, the participants are encouraged to submit alternative proposals.

The main principle stated by the Tool is that the cohort should reasonably “reflect the type of power plants that would likely be built in the absence of the project activity” (quoted from the Tool) which means that the BM capacity is counterfactual and the cohort is assembled just to determine the parameters of such a capacity to calculate GHG emissions.

The sample group of power units used to calculate the BM consists of either:

- (a) The set of five power units that were built most recently (in 10 years period), or
- (b) The set of power capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that were built most recently.

Capacity additions from retrofits of power plants should not be included in the calculations of $EF_{grid,BM,y}$. In case if it is impossible to fulfil conditions (a) and (b) the Tool recommends increasing the time period (to cover more than 10 years) for the new capacities so that five new plants (a) or 20% additions (b) are available.

From mid ‘90s Russia has been recovering after a long and deep economic crisis. Construction of new power capacities was not a common practice that means that in some URESs there were less than five new capacities built. In this case the Tool recommends increasing the time period of new capacities sample. It is proposed to extend the 10 years period to 15.

In this case conditions (a) and (b) are still not met. So an approach, deviating from the Tool recommendations will be used, namely the actual sample is extended by the new plant(s)/unit(s) which are currently under construction.

In the Table Anx.2.6 lists all the plants/units commissioned since 1993 and under construction in URES “Centre”.

Table Anx.2.6: URES “Centre”. Power plants/units commissioned since 1993 and under construction

N	Power plant/unit	Year of commissioning	Capacity, MW	Technology	Fuel
Commissioned in 1993-2008					
1	“Lutch” CHP	2005	60	CC GT	Gas
2	Moscow CHP-27	2007	450	CC GT	Gas
3	Moscow CHP-21	2008	450	CC GT	Gas
4	Ivanovo Combined Cycle	2007	325	CC GT	Gas
5	Ivanovo CHP-1	2005	12	CC GT	Gas
	Total		Less than 20% of URES’s capacity		
Under construction					
6	Kashira TPP (unit No. 3)	2009	330	Steam cycle	Coal
7	Moscow CHP-26 and 27	2009-2010	2 x 450	CC GT	Gas

Source: Energy companies

The table presents seven units while only five should be selected. The Ivanov CHP-1 12 MW unit is too small capacity for the group. Therefore four units built since 2005 and one under construction form the cohort of power plants to be included in the BM²³:

- 4 CC GT of 2x450 MW; 60 MW and 325 MW units
- 330 MW steam cycle with coal (it is given preference to the one of Moscow CHP-26 or CHP-27 (because it is the nearest facility to be put into operation).

For the Kyoto Protocol first commitment period projects participants can chose between one of the two options:

- (1) ex-ante based on the most recent information available on units already built;
- (2) ex-post based on information updated during each relevant monitoring period.

The approach presented above is based upon ex-ante option.

STEP 5: Calculate the build margin emission factor

In line with the Tool the BM emission factor is the generated-weighted average emission factor of all power units m during the year y and is calculated as follows:

$$EF_{grig, BM, y} = \frac{\sum_m EG_{m, y} \times EF_{EL, m, y}}{\sum_5 EG_y} \quad (5)$$

Where:

- $EF_{grig, BM, y}$ – BM emission factor in year y (tCO₂/MWh);
- $EG_{m, y}$ – net quantity of electricity generated and delivered to the grid by the power unit m in year y ;
- $\sum_5 EG_y$ – net quantity of electricity generated and delivered to the grid by the cohort of 5 units in year y ;
- $EF_{EL, m, y}$ – CO₂ emission factor of the power unit m in year y (tCO₂/MWh);
- m – power units included in the BM;
- y – year for which power generation data is available.

Method of $EF_{EL, m, y}$ calculation here is the same as for $EF_{grig, OMsimple, y}$ described under Step 3, i.e. by using specific fuel consumption per 1 kWh of energy output $b_{m, y}$ (kg c.e./kWh).

$$EF_{EL, m, y} = b_{m, y} \times EF_{CO_2, fuel} \quad (6)$$

Where:

- $EF_{CO_2, fuel}$ – fuel emission factor (fuel type weighted) in tCO₂/MJ or tCO₂/t.c.e; the IPCC factors for main types of fuel values;
- $b_{m, y}$ – specific fuel consumption by the unit m (MJ/MWh or t.c.e./MWh).

b_m is accepted according either to the operational reports, or from the projects' designs or from the standards established by the "Concept of Technical Policy of JSC UES" (2005) for the new equipment.

In the Russian Federation individual plant based data is considered strictly confidential. Therefore the specific factors of the power units (or similar power units) from open sources were used.

²³ This cohort reflects the type of power plants that would likely be built in the absence of the project activity

The background data for $EF_{grid, BM, y}$ calculation is presented in the Table Anx.2.7.

Table Anx.2.7: background data for $EF_{grid, BM, y}$ calculation

Indicator	Unit	Natural gas-fired CC GT unit 450 MW*	Natural gas-fired CC GT unit 450 MW*	Natural gas-fired CC GT unit 325 MW**	Natural gas-fired CC GT unit 60 MW***	330 MW steam cycle with coal****
Electric capacity,	MW	450	450	325	60	330
Capacity utilization	%			60*****		60*****
Annual net generation of electricity	MWh	2,567,626	2,567,626	1,708,200	235,290	1,734,480
Specific fuel consumption	kg c.e. /kWh	0.2508	0.2508	0.2343	0.2268	0.295
	MJ/MWh	7.356×10^3	7.356×10^3	6.872×10^3	6.652×10^3	8.6524×10^3
Fuel		Natural gas	Natural gas	Natural gas	Natural gas	Coal
Fuel emission factor	tCO ₂ /MJ	0.0561×10^{-3}	0.0561×10^{-3}	0.0561×10^{-3}	0.0561×10^{-3}	0.961×10^{-3}

Source: * average of the reported data for similar plants (Kaliningrad CHP-450 and North-Western CHP-450);
 ** characteristics of GTs and CC GT typical projects;
 *** the report of GT “Lutch”;
 **** according to the standards from the Concept of Technical policy of JSC UES;
 ***** assumed based on the 2007 figure from RosStat RF of 52% for TPPs; for high capacity and TPPs of condensed type assumed as 60%.

The results of $EF_{EL, m, y}$ calculation are presented in the Table Anx.2.8.

Table Anx.2.8: Results of $EF_{grid, BM, y}$ calculation

Indicator	Unit	Natural gas-fired CC GT unit 450 MW	Natural gas-fired CC GT unit 450 MW	Natural gas-fired CC GT unit 325 MW	Natural gas-fired CC GT unit 60 MW	330 MW steam cycle with coal
Power unit CO ₂ emission factor	tCO ₂ /MWh	0.4127	0.4127	0.3855	0.3732	0.8315
Average weighted BM emission factor	tCO ₂ /MWh	0.489				

BM emission factor is ex-ante for period 2008-2012.

STEP 6: Calculate combined margin emission factor

The combined margin emission factor (CM) is calculated as follows:

$$EF_{grid, CM, y} = w_{OM} \times EF_{grid, OM, y} + w_{BM} \times EF_{grid, BM, y} \tag{7}$$



Where:

$EF_{grid, CM, y}$	CM emission factor in year y (tCO ₂ /MWh);
$EF_{grid, OM, y}$	OM emission factor in year y (tCO ₂ /MWh);
$EF_{grid, BM, y}$	BM emission factor in year y (tCO ₂ /MWh);
w_{OM}	weight of OM emission factor;
w_{BM}	weight of BM emission factor.

In most cases the Tool recommends to apply $w_{OM} = w_{BM} = 0.5$. But developers may propose other weights, as long as $w_{OM} + w_{BM} = 1$.

As a starting point the weighting factor for w_{OM} is taken as 0.5.

When looking at the factor for w_{BM} the specific of the Russian power system have to be taken into account. The Russian power system has a big quantity of old, worn-out low efficient power plants being in operation for decades. According to the JSC "UES of Russia" average turbines operational life time is around 30 years. Most of these capacities were put in operation in 1971-1980 that corresponds to 31.4% of the whole installed capacities.

In accordance with General Scheme²⁴, dated 22 February 2008, it was planned to approximately 33 GW of old capacity has to be dismantled by 2015. To meet the growth in demand new energy units with total capacity of 120 GW will be commissioned by 2015. This means that the JI project will not only avoid the construction of new power plants, but also accelerate the decommissioning of existing capacities. Given the impact of the financial crises on demand growth and the capability to finance new projects, the new estimation²⁵ (September 2008) expects that out of the planned 120 GW only about 80 GW will be operational by 2015. Out of the 33 GW of old capacity only 10 GW will be dismantled. This means that 1 GW of any project delay is a delay of 0.5 GW of old capacity dismantling. So the effect of the JI project on the acceleration of decommissioning of existing capacities will only be stronger as result of the financial crisis.

The estimation, that the effect of the JI project on the decommissioning of power plants and the delays of new power plants construction is approximately 50% / 50%. For the avoidance of new power plants the emission factor of the BM is representative whereas for the accelerated decommissioning effect the emission factor of the OM is representative.

Therefore effective $w_{OM} = 0.50 + 0.25 = 0.75$ and $w_{BM} = 0.25$.

The resulting grid factor is $EF_{grid, CM, y} = 0.540$ tCO₂/MWh. CM emission factor is ex-ante for period 2008-2012, because OM and BM emission factors are ex-ante as well. This emission factor is the baseline emission factor ($EF_{BL, CO_2, y}$) which is used to establish the baseline emissions of the baseline scenario

²⁴ <http://www.e-apbe.ru/scheme/>

²⁵ <http://www.e-apbe.ru/library/detail.php?ID=11106>



Annex 3

MONITORING PLAN

See Section D for monitoring plan.