Annex 1 to:
Implementing clean coal projects under Kyoto

Annex 1a

Joint Implementation Project Design Document for Clean Coal Technologies in Romania

PREAMBLE:

The following document considers hypothetical case studies using the guidelines established by the Ministry of Economic Affairs of The Netherlands for Project Design Documents of Joint Implementation Projects (Volume 2a, 2002). The JI country is Romania and the document relies significantly on information and data from Termoelectrica (Romania) website (www.termoelectrica.ro), Energy Overview of Romania (USDOE, 2004), and the previous JI baseline study made by KPMG for Portile de Fier I Hydroelectric Plant in Romania (2002).

The template for JI PDD documents as required by the Ministry of Economic Affairs of the Netherlands is followed throughout, with some modifications in baseline options/scenarios to suit the new coal technologies applications. Some of the sections of this document, however, cannot be meaningfully addressed in a purely hypothetical case study. In those instances, the headings for these sections are retained but the section left blank.

1.0 PROJECT INFORMATION

This is a hypothetical case study of a proposed super-critical coal-fired power plant for construction in one of the provinces/regions in Romania. Other clean coal technologies including Integrated Gasification Combined Cycle (IGCC) Circulating Fluidised Bed Combustion (CFBC) Pressurised Fluidised Bed Combustion (PFBC) and Pressurised Circulating Fluidised Bed Combustion (PCFBC) were also considered for comparison purposes.

1.1 Project characteristics *(Hypothetical only)*

Supplier's name and address: *(Hypothetical only)*

Company name:

Address:

Zip code + city address:

Postal address:

Zip code + city postal address:

Country:

Contact person:

Job title:

Telephone number:

Fax number:

E-mail address:

1.2 Local contact

1.3 Other parties involved (co-investor, owner, operator, user, etc.)

1.4 Project Abstract

1.4.1 Project Title

Construction of 2 x 600 MWe Mintia Supercritical Coal-Fired Power Plants

1.4.2 Abstract

Project location: The 2 x 600 MWe Mintia Super-Critical Coal-Fired Power plant will be located in the power plant site of Mintia in Deva, Hunedoara region **(hypothetical plant location only)** of Romania. The location map is shown below.

Source: US DOE (2004)

Project starting date (Hypothetical only): 1 January 2005

Construction starting date: 1 January 2005

Construction finishing date: 31 December 2007

The project will consist of 2 x 600 MW Super-Critical Coal-fired generating units or a total installed capacity of 1,200 MW. It will replace electricity generation of low efficiency lignite coal-fired power plants and reduce CO_2 emissions from these power plants. Its construction and subsequent operation is considered important to Romania's domestic manufacturing level and restructuring of its electric industry.

Assumed parameters of the super-critical plant are shown in the following table.

Main Parameters of the Super-Critical Coal-Fired Power Plant

Base year (for technical, economic data): 2004

Technical data (net)*	
Unit Capacity, MW	600
No. of units	2
Total Installed capacity (MW)	1200
% Utilization (per year)	57
Full load utilization hours (h/year)	4993
Energy generation (GWh/year)	5992
Fuel consumption (million tonnes/yr), Coal (ideal)	2.996
Net efficiency (%)	42
Fuel consumption (million tonnes/yr), Coal (actual)	8.322
Designed life period (years)	25
Carbon content of fuel coal (%)	20
Heating value of coal used (MJ/kg)	7.2
Heating value of standard coal, MJ/kg	29.307
Economic data	
Total capital cost (US$ Million)**	1,479
Direct capital cost (at US$1,060/kW)	*1,272*
Indirect capital cost (US$/kW), 16.3% of DCC	*207*
Fuel costs (US$ million)***	416
Fuel costs (US$/$GWh_f$)	0.0694
Interest rate (% p.a.)	6
Lifetime (years)	25
Crediting period (years)	5
Activity period (years)	25
Labour costs (US$ Millions/year)****	44
Maintenance costs (US$ millions/year)****	88
Environmental data	
CO_2 emission factor (kgCO_2/kWh_f)	0.873

Note: 1 US$ = 32,046 ROL – Romania Lei (28 October 2004)
* KPMG Environmental Services (Sept. 2002)
** Scott & Nilsson (IEA, 1999)
*** Coal cost = $50/tonne
**** Tavoulares and Charpentier (World Bank, 1995)
Direct capital cost = Plant facility capital + General facility capital
Indirect capital cost = Engineering & Administration + Contingencies + Capital costs during construction + Commissioning cost + Inventory capital = 16.4% of Direct capital cost
Labour cost = 3% of Direct capital cost
Maintenance costs = 6% of direct capital cost

The weighted average for current sub-critical thermal plant utilisation is approximately 26%. It is considered likely that in an effort to get maximum return on the significant capital investment in the new plants, a much higher utilisation will be achieved. The highest utilisation of existing thermal plant is approximately 57% (IEA Coal Research 1994) and this figure is assumed for the new plants.

The following parameters were assumed for the other coal plant technologies:

Base year (for technical, economic data): 2004

	CFBC	PFBC	PCFBC	IGCC
Technical data (net)*				
Unit Capacity, MW	250	250	250	300
No. of units	1	1	1	1
Total Installed capacity (MW)	250	250	250	300
% Utilization (per year)	57	57	57	57
Full load utilization hours (h/year)	4,993	4,993	4,993	4,993
Energy generation (GWh/year)	1,248	1,248	1,248	1,498
Fuel consumption (million tonnes/yr), Coal (ideal)	0.6241	0.6241	0.6241	0.7489
Net efficiency (%)	39	43	43	45
Fuel consumption (million tonnes/yr), Coal (actual)	1.6003	1.4514	1.4514	1.6643
Designed life period (years)	25	25	25	25
Carbon content of fuel coal (%)	20	20	20	20
Heating value of coal used (MJ/kg)	7.2	7.2	7.2	7.2
Heating value of standard coal, MJ/kg	29.307	29.307	29.307	29.307
Economic data				
Total capital cost (US$ Million)**	337	347	347	475
Direct capital cost (at US$ Million)	*290*	*298*	*298*	*408*
@ Direct capital cost (at US$/kW)	*1,160*	*1,190*	*1,190*	*1,360*
Indirect capital cost (US$ Million), 16.3% of DCC	*47*	*49*	*49*	*67*
Fuel costs (US$ million)*	80.02	72.57	72.57	83.22
Fuel costs (US$/$GWh_f$)***	0.064	0.058	0.058	0.056
Interest rate (% p.a.)	6	6	6	6
Lifetime (years)	25	25	25	25
Crediting period (years)	5	5	5	5
Activity period (years)	25	25	25	25
Labour costs (US$ Millions/year)	10.1	10.4	10.4	14.25
Maintenance costs (US$ millions/year)	20.2	20.8	20.8	28.5
Environmental data				
CO_2 emission factor ($kgCO_2/kWh_f$)	0.940	0.853	0.853	0.815

Note: 1 US$ = 32,046 ROL – Romania Lei (28 October 2004)
* KPMG Environmental Services (Sept. 2002)
** Scott & Nilsson (IEA, 1999)
*** Coal cost = $50/tonne
**** Tavoulares and Charpentier (World Bank, 1995)
Direct capital cost = Plant facility capital + General facility capital
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Labour cost = 3% of Direct capital cost
Maintenance costs = 6% of direct capital cost

1.5 Background and justification

1.5.1 Project Goals

The project goals are:

- Reduction of air emissions by replacing the electricity produced by old & less efficient coal-fired power plants in Romania;
- Usage of clean coal energy technology (the project has lower environmental impact during its construction and operation than the old coal-fired power plants in Romania);
- Installation of 1,200 MW Super-Critical coal-fired power plants with an annual energy production of 5,992 GWh.

1.5.2 Purpose of the Project

The project will supply electricity to the Romanian National Electricity System.

1.5.3 Project Results

The 1,200 MW JI Project will provide 5,992 GWh per year of electricity to the grid, improve the Romania national electricity supply system, and lessen the emissions from old thermal power plants.

2.0 GHG SOURCES AND SINKS AND PROJECT BOUNDARIES

2.1 Project boundaries

The project impacts around the Project's system boundaries will be assessed. All project effects on GHG emissions within the system boundaries will be considered and used for the baseline scenarios.

The Guidelines set by the Ministry of Economic Affairs of The Netherlands (2002) set two principles to determine the project boundaries:

a) Principle of control – project boundaries should include all relevant emission that can be controlled or influenced by the project;
b) Relevant GHG emissions, either, one step upstream and one step downstream from the project should be included within project boundaries.

2.2 Direct on-site emissions

Direct GHG emissions can be produced from:

- Combustion of coal, and
- Combustion of diesel during plant start-up

During start-up of the thermal generation unit, diesel is used in the combustor for firing of the pulverized coal. This limited amount of diesel and its GHG emission may be considered insignificant as compared to the large amount during combustion of coal. It is then assumed that the CO_2 emission during diesel combustion is negligible for the JI super-critical and current coal-fired power plant units in Romania.

2.3 Indirect on-site emissions

Indirect GHG emission sources for the JI case are produced during the following processes:

- Manufacture of equipment and building materials
- Transport of equipment and building materials
- Manufacture of power transmission lines
- Construction of power transmission lines
- Construction of power house

These GHG emissions, however, will not be evaluated since:

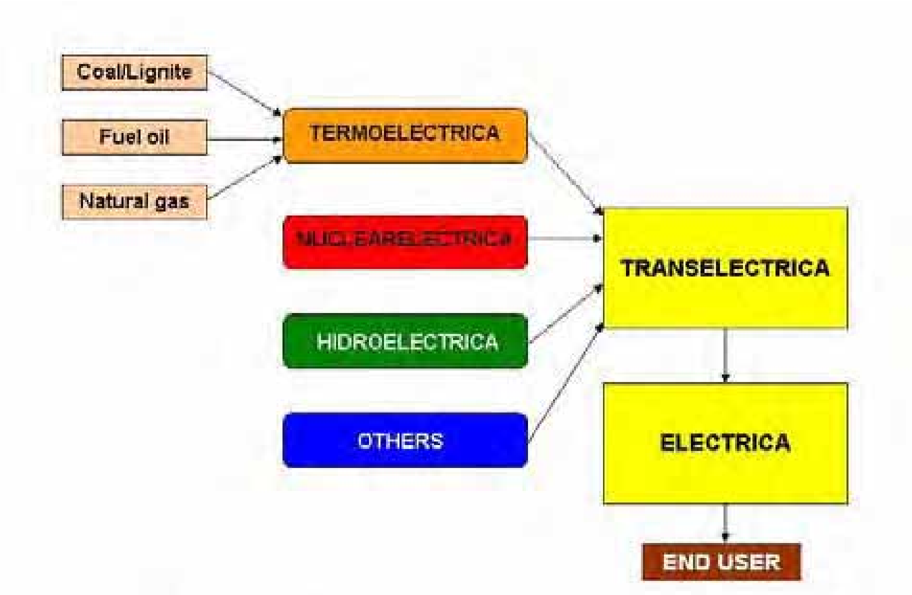
- They are not measurable and cannot be monitored on a cost effective basis
- They are negligible for the JI case and no significant emission reduction or change is induced by this activity.

The JI Project Boundary is selected as the physical boundary of the power plant, whereas the system boundary is identified as the national power system.

3.0 DESCRIPTION OF THE CURRENT DELIVERY SYSTEM

3.1 Flowchart of the current delivery system with its main components and connections

The main components and connections of the current Romania energy delivery system are shown below:



Current Romanian energy delivery system

Source: KPMG Environmental Services (Sept. 2002)

3.2 Status and adequacy of the current delivery system

The Ministry of Industry and Resources supervises the energy sector and formulates the policy and the strategy in this field.

In June 1998, the Romanian Electricity Authority (RENEL) was restructured and created the National Electricity Company (CONEL). In October 1998, the National Electric and Heat Regulatory Authority (ANRE) became the independent institution regulating the electricity market.

On 31 July 2000, the Romanian government divided CONEL into four companies:

a) Transelectrica S.A. - the national company for electricity transmission, power system operation, dispatching, and operation of the National Power Transmission System. It develops and operates open access to the wholesale electricity market, ensures the cross boundary electricity connections and provides the required infrastructure for performing these activities.

b) Termoelectrica S.A. - the national company for the production of electrical and thermal energy. It is the main electricity producer in Romania. It: generates electricity from coal, gas and fuel oil thermal power plants, district heating and related fuel supply.

c) Hidroelectrica S.A - the commercial company for production and delivery of hydroelectric power. It is the second largest electricity producer in Romania. It generates electricity from hydropower, provides ancillary technological services to ensure operational safety of the national power system and provides water management services of national and regional interest (flood protection, water sources, water management services).

d) Electrica S.A. – the commercial company for electricity distribution and supply.

Adequacy of the current delivery system

Many thermal and hydro plants built before the revolution became redundant after 1989 as a result of a decline in electricity consumption and lack of funding resources. However much of the technology used in Romania's thermal power plants is from the 1960's and early 1970's and it is estimated that approximately 40% of the current total installed capacity will need to be rehabilitated or replaced by 2010.

.3 Operation modes of the current delivery system

Romania has an extensive interconnected power transmission and distribution network with an overall length of about 368,000 miles, and a total transformer capacity of about 172,000 MVA. The national grid operates on 750 kV, 400 kV, and 220 kV for transmission and 20 kV, 10 kV, 6 kV, 1 kV, and 0.4 kV for distribution. The current electricity grid in Romania is shown on the next page.

Source: US DOE (2004)

3.4 Energy generation

3.4.1 Thermal power plants

Lignite and hard coal-fired power plants:

The thermal plants use lignite, hard coal, natural gas, fuel oil or a combination of gas and fuel oil for producing heat and electricity. Some of these plants can produce only electricity and they are called condensation groups and others produce both thermal and electric power and they are called cogeneration groups. For the purpose of this study, these thermal power plants are producing electricity for the national grid system.

Lignite & hard coal-fired power plants

Plant	Capacity MWe	2004 Electricity Generation (GWh)	IPCC Carbon Emission Factor ($kgCO_2/kWh$)	CO_2 Emissions (tCO_2)	% Generation Mix
Turceni	1980	3,467.3	1.025	3,554,009	
Rovinari	1320	2,802.4	1.061	2,973,309	
Mintia	1260	3,746.3	0.900	3,371,660	
Işalniţa	630	2,156.7	1.195	2,577,240	
Doiceşti	400	570.8	0.962	549,073	
Craiova II	300	990.9	0.152	150,612	
Paroşeni	300	260.8	1.958	510,639	
Oradea I	205	422.7	1.938	819,123	
Oradea II	150	292.7	2.062	603,479	
Giurgiu	100	58.6	2.926	171,496	
Iaşi II	100	247.1	1.917	473,616	
Suceava	100	206.5	1.824	376,621	
Braşov	100	237.5	2.334	554,372	
Arad C	50	225.6	2.184	492,656	
Bacău	50	151.9	2.160	328,197	
Zalău	24	45.4	0.960	43,586	
Other plants	2,262	5,153.0	1.2	6,183,576	
Total	9,331	21,036.0	1.128	23,733,264	37.4

Source: KPMG Environmental Services (Sept. 2002)
US DOE (2004)

Gas & Fuel oil-fired power plants

Plant	Capacity MWe	2004 Electricity Generation (GWh)	IPCC Carbon Emission Factor ($kgCO_2/kWh$)	CO_2 Emissions (tCO_2)	% Generation Mix
Brăila	960	908.1	0.570	517,618	
Iernut	800	1,976.6	0.120	237,198	
Bucureşti Sud	550	1,260.3	1.463	1,843,798	
Galați	535	958.6	0.893	856,025	
Borzeşti K	420	235.1	0.065	15,279	
Brazi T	360	850.3	1.290	1,096,851	
Bucureşti Vest	250	817.5	0.816	667,056	
Palas	250	213.8	3.375	721,663	
Progresul	200	554.6	0.929	515,260	
Iaşi H	150	428.1	1.355	580,020	
Piteşti Sud	136	200.4	2.106	422,133	
Borzeşti T	110	392.7	1.205	473,144	
Grozăveşti	100	345.7	1.430	494,382	
Reşița	12	56.4	2.367	133,395	
Titan	8	21.0	4.739	99,282	
Piteşti Găvana	6	32.5	6.278	204,167	
Timişoara Centru	4	15.7	16.154	252,859	
Other plants	1,602	3,086.7	1.1	3,395,421	
Total	6,453	12,354.0	1.014	12,525,550	22.0

Source: KPMG Environmental Services (Sept. 2002)
US DOE (2004)

3.4.2 Hydroelectric power plants

The details of Hidroelectrica power plants are shown below:

Plant	Capacity MWe	2004 Electricity Generation (GWh)	IPCC Carbon Emission Factor ($kgCO_2/kWh$)	CO_2 Emissions (tCO_2)	% Generation Mix
Râmnicu Vâlcea	1,625	3,795	0	0	
Porțile de Fier	1,354	6,561	0	0	
Bistrița	636	1,656	0	0	
Cluj	539	997	0	0	
Curtea de Argeş	525	964	0	0	
Hațeg	485	683	0	0	
Sebeş	346	606	0	0	
Târgu Jiu	193	449	0	0	
Caransebeş	148	164	0	0	
Buzău	77	203	0	0	
Other plants	475	1,457	0	0	
Total	6,403	17,535	0	0	31.1

Source: KPMG Environmental Services (Sept. 2002)
US DOE (2004)

3.4.3 Nuclear power plant

Romania has one nuclear plant, the Cernavoda 1 power station, 90 miles east of Bucharest. It went online in December 1996, has an installed capacity of 750 MW, and accounts for approximately 10% of the total energy production in Romania.

By the end of 2004, the second Cernavoda nuclear unit (Cernavoda 2) will be on-line, and for study purposes, its energy generation is projected to be similar to Cernavoda 1 (at 750 MW and 5,355 GWh).

Nuclear power plants

Plant	Capacity MWe	2004 Electricity Generation (GWh)	IPCC Carbon Emission Factor ($kgCO_2/kWh$)	CO_2 Emissions (tCO_2)	% Generation Mix
Cernavoda 1	750	5,355	0	0	9.5

Source: KPMG Environmental Services (Sept. 2002)
US DOE (2004)

3.5 National Strategy

In 2001, the Romanian Government approved the National Strategy for Energy Development in the Medium Term (2001-2004). It was designed to be compatible with the energy policies of the EU, especially in terms of energy efficiency and environmental standards. The three main features of the strategy are:

- Competitive market for energy
- Privatization of the electric distribution system and then the electric generation system
- Stimulating new investments in energy

The strategy aims to reduce energy intensity by 3% annually and hopes to stimulate investments in energy efficiency. This will be done by promoting private initiatives in energy services, encouraging new high efficiency energy technologies, and international cooperation in energy efficiency.

4.0 KEY FACTORS INFLUENCING THE BASELINE AND THE PROJECT

4.1 Legal

The current government policy is to develop an energy sector that promotes a market-oriented economy. Legislation, either currently under development, or in the process of being passed to help implement this policy, includes:

- A new petroleum law;
- Regulations for electricity and heat with respect to technical standards and the relationship between suppliers and customers;
- A new electricity law for regulating the activity of the electricity generating companies, the access to the electricity transmission system and investment in the electricity sector;
- New regulations or standards for electricity use;
- A law on energy conservation.

4.2 GHG Policies in Romania

Romania signed the Kyoto Protocol, which establishes the terms and the rules of monitoring the gases that determine the greenhouse effect for the Earth and ratified it through the Law no 3/2001. Romania ratified the Kyoto Protocol and committed itself to reduce the level of its GHG emissions by 8% from its emission level in 1989.

4.3 Economic and Political

Romania has made considerable progress towards the development of democratic institutions and its market economy. The centrist coalition government, elected in 1996, was very well received by western institutions and implemented a far-reaching economic reform program. The program will enable Romania to make a rapid transition to market economy.

For the purpose of this study, Romania's GDP growth rate is predicted to be a conservative 3% based on figures registered from the previous years.

Component	2000	2001	2002	2003
Annual GDP Growth Rate (%)	2.2	5.3	4.9	4.7
Inflation rate, end-of-year, %	45.7	34.5	22.5	15.2
Exchange rate (Lei per $)	21,689	29,358	34,098	34,096

Sources: United Nations Economic Commission for Europe (UN/ECE) - 1993-99
CIA World Factbook, USA DOE/EIA, World Bank

The Romanian energy strategy is closely linked with the national strategy of economic development of Romania. The level of economic growth ensures the necessary financial resources for the development of the energy sector, as well as a living standard that allows the population to socially accept the electricity prices.

4.5 Environmental

The Ministry of Waters and Environmental Protection (MWEP) is the central environmental authority and within each of the 42 counties (including Bucharest as municipality) there is an Environmental Protection Inspectorate (EPI), which represents the local environmental authority. MWEP is responsible for adoption of the Aquis Communitaire in the environmental protection field. In this process it is working closely with other ministries.

The Ministry of Industry and Resources intends to harmonise the Romanian regulations regarding the environmental impact of energy processes with EU regulations, both in the medium and long term. In order to reduce the environmental impact in the energy sector taking into account the EU regulations, the following actions will be taken:

- implementation of rehabilitation and modernisation projects;
- building ecological landfills for storing the slag and ash resulting from thermal processes;
- monitoring the quality of environment in the areas where important energy producers are located;
- rehabilitation of contaminated soils and reuse of those areas for agricultural purposes.

4.6 Technical

Most of the technology in the Romanian electricity industry is old and needs to be modernized or replaced. The Government policy is to attract potential investors in order to facilitate the purchase of new clean technologies or the modernization of the existing ones. Within the electricity sector, approximately 60% of Romania's existing power capacity is more than 20 years old, and about 10 GW will need to be rehabilitated or replaced by 2010.

5.0 IDENTIFICATION OF THE MOST LIKELY BASELINE AND THE ASSOCIATED GHG EMISSIONS

Six (6) baseline options were constructed to compare with the performance of the super-critical coal-fired power plants and the other coal-fired technologies.

5.1 Assumptions

1. The starting point of the baseline is the current situation (Year 2004).
2. The crediting period of the project will be 5 years or the commitment period of 2008-2012
3. The JI Project will be operational by 2008 and its output will remain constant during the crediting period.
4. The JI Project will replace the electricity generated from old and less efficient coal-fired power plants in the Romanian national power system.
5. The emissions considered are related only to electricity generation.
6. On site losses and grid losses are excluded from the system boundaries.
7. Rules, guidelines and procedures developed by the Ministry of Economics Affairs of the Netherlands were incorporated into the process.

5.2 Description of the baseline scenarios

We considered the current situation (2004) as the starting point, with emphasis on electricity generation figures in Romania gathered from DOE/EIA and KPMG studies. The following baseline scenarios/options were developed:

- Option 1 - Existing electricity generation (2004) from coal, hydro, nuclear, and gas/oil remains constant from 2005 up to the crediting period (2008-2012), no growth.
- Option 2 - Standardised baseline scenario for Romania (per Ministry of Economic Affairs of the Netherlands Guidelines, Volume 2a, Annex B, 2002)
- Option 3 - 3% growth in electricity generation for 2008-2012. Constant generation from hydro (2004-2012) and nuclear (2004-2007). Another nuclear plant will be operational at same constant electricity generation as the first plant (2008-2012). Additional electricity generation requirements will only be provided by coal and oil/gas-fired power plants
- Option 4 – As for Option 3, but electricity generation from coal and oil/gas-fired power plants will be replaced by new coal-fired technology (excludes hydro and nuclear).
- Option 5 - Same as Option 4 but takes into account correction for operations at margin.
- Option 6 - the existing coal and oil/gas-fired power plants will gradually switch to natural gas as the only fuel used in the next 30 years (2030).

5.2.1 Option 1

The existing electricity generation and fuel mix from coal, hydro, nuclear, & oil/gas power plants (as of 2004) remains constant from 2005 up to the crediting period (2008-2012). These power plants are summarized below:

Plant	Capacity MWe	2004 Electricity Generation (GWh)	IPCC Carbon Emission Factor ($kgCO_2/kWh$)	CO_2 Emissions (tCO_2)	% Generation Mix
Lignite and Hard Coal	9,331	21,036	1.128	23,733,264	37.38
Gas & Fuel Oil	6,453	12,354	1.014	12,525,550	21.95
Hydro	6,403	17,535	0	0	31.16
Nuclear	750	5,355	0	0	9.51
Total	22,937	56,280	0.644	36,258,814	100.0

Source: KPMG Environmental Services (Sept. 2002)
US DOE (2004)

The electricity generation output of the Project will be 5,992 GWh/year from 2008-2012. Option 1 will have the following emission reductions/additions:

Crediting Period	2008	2009	2010	2011	2012
Super-Critical Coal					
Generation (GWh)	5,992	5,992	5,992	5,992	5,992
CEF ($kgCO_2/kWh$)	0.873	0.873	0.873	0.873	0.873
Baseline Option 1					
CEF ($kgCO_2/kWh$)	0.644	0.644	0.644	0.644	0.644
Difference ($kgCO_2/kWh$)	(0.229)	(0.229)	(0.229)	(0.229)	(0.229)
Emission reductions/ (Emission additions) (kt CO_2)	(1372)	(1372)	(1372)	(1372)	(1372)
Total Emission additions for 2008-2012 (kt CO_2)	(6,860)				

Source: KPMG Environmental Services (Sept. 2002)
US DOE (2004)

5.2.2 Option 2

Based on the standardized emission factors defined in the Guidelines of the Ministry of Economic Affairs - The Netherlands (Volume 2a, Annex B, 2002), the baseline electricity grid CO_2 emission factors (CEF) for JI projects in Romania for 2008-2012 are as follows:

CEF Romania	Year				
	2008	2009	2010	2011	2012
$kgCO_2/kWh$)	0.606	0.594	0.583	0.571	0.559

Note: Values are only to be used if electricity production off-site (elsewhere on the gird) is replaced.
Source: MEA-Netherlands (Sept 2002)

At the JI Project electricity generation output of 5,992 GWh/year from 2008-2012, this option will have the following emission reductions/additions:

Crediting Period	2008	2009	2010	2011	2012
Super-Critical Coal					
Generation (GWh)	5,992	5,992	5,992	5,992	5,992
CEF ($kgCO_2/kWh$)	0.873	0.873	0.873	0.873	0.873
Baseline Option 2					
CEF ($kgCO_2/kWh$)	0.606	0.594	0.583	0.571	0.559
Difference ($kgCO_2/kWh$)	(0.267)	(0.279)	(0.290)	(0.302)	(0.314)
Emission reductions/ (Emission additions) (kt CO_2)	(1600)	(1672)	(1738)	(1810)	(1881)
Total Emission additions for 2008-2012 (kt CO_2)	(8,701)				

Source: MEA-Netherlands (Sept 2002)

5.2.3 Option 3

Similar to Option 1, plus the consideration that there would be a conservative 3% growth in electricity requirements of Romania from 2005-2012 to account for its 3% GDP growth. Coal and gas/fuel oil will provide for these growth requirements, as electricity generation from hydro will remain constant from 2005-2012 and those from nuclear plants from 2005-2007. From 2008-2012, the 2[nd] nuclear plant will be operational at constant generation similar to the first unit.

The details of these power plants for 2008-2012 are shown below:

Electricity Generation (GWh)

Plant	2008	2009	2010	2011	2012
Lignite and Hard Coal	23,734	25,514	27,377	29,293	31,285
Gas & Fuel Oil	11,456	11,571	11,687	11,804	11,922
Hydro	17,535	17,535	17,535	17,535	17,535
Nuclear	10,710	10,710	10,710	10,710	10,710
Total	63,435	65,330	67,309	69,342	71,452

Source: KPMG Environmental Services (Sept. 2002)
US DOE (2004)

IPCC CEF (kgCO_2/kWh)

Plant	2008	2009	2010	2011	2012
Lignite and Hard Coal	1.128	1.128	1.128	1.128	1.128
Gas & Fuel Oil	1.014	1.014	1.014	1.014	1.014
Hydro	0	0	0	0	0
Nuclear	0	0	0	0	0
Weighted average	0.605	0.620	0.635	0.649	0.663

Source: KPMG Environmental Services (Sept. 2002)
US DOE (2004)

Emissions, ktonnesCO_2

Plant	2008	2009	2010	2011	2012
Lignite and Hard Coal	26,772	28,780	30,881	33,043	35,289
Gas & Fuel Oil	11,616	11,733	11,851	11,969	12,089
Hydro	0	0	0	0	0
Nuclear	0	0	0	0	0
Total	38,388	40,513	42,732	45,012	47,378

Source: KPMG Environmental Services (Sept. 2002)
US DOE (2004)

At the JI Project electricity generation output of 5,992 GWh/year from 2008-2012, this option will have the following emission reductions/additions:

Crediting Period	2008	2009	2010	2011	2012
Super-Critical Coal					
Generation (GWh)	5,992	5,992	5,992	5,992	5,992
CEF (kgCO_2/kWh)	0.873	0.873	0.873	0.873	0.873
Baseline Option 3					
CEF (kgCO_2/kWh)	0.605	0.620	0.635	0.649	0.663
Difference (kgCO_2/kWh)	(0.268)	(0.253)	(0.238)	(0.224)	(0.210)
Emission reductions/ Emission additions (kt CO_2)	(1,606)	(1,516)	(1,426)	(1,342)	(1,258)
Total Emission additions for 2008-2012 (kt CO_2)			(7,148)		

Source: KPMG Environmental Services (Sept. 2002)
US DOE (2004)

5.1.4 Option 4

This is a similar scenario to Option 3, but excludes hydro and nuclear power electricity generation and focuses only on the replacement of electricity from coal and oil/gas-fired power plants by the new coal-fired technology.

The details of the coal and oil/gas-fired power plants for 2008-2012 will be:

Electricity Generation (GWh)

Plant	2008	2009	2010	2011	2012
Lignite and Hard Coal	23,734	25,514	27,377	29,293	31,285
Gas & Fuel Oil	11,456	11,571	11,687	11,804	11,922
Total	35,190	37,085	39,064	41,097	43,207

Source: KPMG Environmental Services (Sept. 2002)
US DOE (2004)

IPCC CEF ($kgCO_2/kWh$)

Plant	2008	2009	2010	2011	2012
Lignite and Hard Coal	1.128	1.128	1.128	1.128	1.128
Gas & Fuel Oil	1.014	1.014	1.014	1.014	1.014
Weighted average	1.091	1.092	1.094	1.095	1.097

Source: KPMG Environmental Services (Sept. 2002)
US DOE (2004)

Emissions, ktonnesCO_2

Plant	2008	2009	2010	2011	2012
Lignite and Hard Coal	26,772	28,280	30,881	33,043	35,289
Gas & Fuel Oil	11,616	11,733	11,851	11,969	12,089
Total	38,388	40,513	42,732	45,012	47,378

Source: KPMG Environmental Services (Sept. 2002)
US DOE (2004)

At the Project's electricity generation output of 5,992 GWh/year from 2008-2012, this option will have the following emission reductions/additions:

Crediting Period	2008	2009	2010	2011	2012
Super-Critical Coal					
Generation (GWh)	5,992	5,992	5,992	5,992	5,992
CEF ($kgCO_2/kWh$)	0.873	0.873	0.873	0.873	0.873
Baseline Option 4					
CEF ($kgCO_2/kWh$)	1.091	1.092	1.094	1.095	1.097
Difference ($kgCO_2/kWh$)	0.218	0.219	0.221	0.222	0.224
Emission reductions (kt CO_2)	1,306	1,312	1,324	1,330	1,342
Total emission reductions for 2008-2012 (kt CO_2)			6,614		

Source: KPMG Environmental Services (Sept. 2002)
US DOE (2004)

Option 4, in which the new plant only replaces existing thermal power, results in emission reductions of 6,614 kt CO_2 being realized during the period 2008-2012.

5.1.5 Option 5

This option is similar to Option 4 as it assumes that the JI project output replaces only the electricity produced by the thermal power plants and the efficiency of these plants remains constant in the future.

However, a correction factor in shares between electricity produced by lignite and hard coal-fired power plants and those from fuel oil and gas-fired power plants is applied to account for the fact that gas and oil fired plant of high cost variability are more frequently operated at the margin than low to medium variable cost coal-fired plant. (Ministry of Economic Affairs of The Netherlands Guidelines 2002, Volume 2a, Annex B).

This means that the original generation mix from Option 4 shown below:

Generation mix (%)

Plant	2008	2009	2010	2011	2012
Gas & Fuel Oil	32.55	31.20	29.92	28.72	27.59
Lignite and Hard Coal	67.45	68.80	70.08	71.28	72.41
Total	100.00	100.00	100.00	100.00	100.00

Source: MEA-Netherlands (Sept 2002)
KPMG Environmental Services (Sept. 2002)
US DOE (2004)

Will have a correction factor, using the following formula where it is assumed that gas and oil fired plant operate at the margin with a marginal frequency factor of 0.5.

$C_{corrected} = C + 0.5D$
$D_{corrected} = 1\text{-}C_{corrected}$

Where C = Original generation mix of gas and fuel oil power plants and
D = Original generation mix of lignite and hard coal power plants

The corrected generation mix will then be:

Generation mix (%)

Plant	2008	2009	2010	2011	2012
Gas & Fuel Oil	66.28	65.60	64.96	64.36	63.80
Lignite and Hard Coal	33.72	34.40	35.04	36.64	36.20
Total	100.00	100.00	100.00	100.00	100.00

Source: MEA-Netherlands (Sept 2002)
KPMG Environmental Services (Sept. 2002)
US DOE (2004)

The corrected electricity generation will be:

Electricity Generation (GWh)

Plant	2008	2009	2010	2011	2012
Gas & Fuel Oil	23,324	24,328	25,376	26,450	27,566
Lignite and Hard Coal	11,866	12,757	13,688	14,647	15,641
Total	35,190	37,085	39,064	41,097	43,207

Source: MEA-Netherlands (Sept 2002)
KPMG Environmental Services (Sept. 2002)
US DOE (2004)

The IPCC CEF will still be the same as Option 4:

IPCC CEF ($kgCO_2/kWh$)

Plant	2008	2009	2010	2011	2012
Lignite and Hard Coal	1.128	1.128	1.128	1.128	1.128
Gas & Fuel Oil	1.014	1.014	1.014	1.014	1.014

Source: MEA-Netherlands (Sept 2002)
KPMG Environmental Services (Sept. 2002)
US DOE (2004)

The corrected emissions will be:

Emissions, ktonnesCO_2

Plant	2008	2009	2010	2011	2012
Gas & Fuel Oil	23,651	24,669	25,731	26,820	27,952
Lignite and Hard Coal	13,385	14,390	15,440	16,522	17,643
Total	37,036	39,059	41,171	43,342	45,595

Source: MEA-Netherlands (Sept 2002)
KPMG Environmental Services (Sept. 2002)
US DOE (2004)

And the new weighted average of CEF will be:

New CEF (kgCO_2/kWh)

	2008	2009	2010	2011	2012
New weighted average	**1.052**	**1.053**	**1.054**	**1.055**	**1.055**

Source: MEA-Netherlands (Sept 2002)
KPMG Environmental Services (Sept. 2002)
US DOE (2004)

At the JI Project electricity generation output of 5,992GWh/year from 2008-2012, this option will have the following emission reductions/additions:

Crediting Period	2008	2009	2010	2011	2012
Super-Critical Coal					
Generation (GWh)	5,992	5,992	5,992	5,992	5,992
CEF (kgCO_2/kWh)	0.873	0.873	0.873	0.873	0.873
Baseline Option 5					
CEF (kgCO_2/kWh)	1.052	1.053	1.054	1.055	1.055
Difference (kgCO_2/kWh)	0.179	0.180	0.181	0.182	0.182
Emission reductions (kt CO_2)	1,073	1,079	1,085	1,091	1,091
Total emission reductions for 2008-2012 (kt CO_2)	**5,419**				

Source: MEA-Netherlands (Sept 2002)
KPMG Environmental Services (Sept. 2002)
US DOE (2004)

This Option results in emission reductions of 5,419 kt CO_2 during the period 2008-2012.

5.1.6 Option 6

This option considers the emission baseline in 2004 for Option 5 (at 1.050 kgCO_2/kWh) as the starting point and the emission factor of new high-efficient gas-fired power production, set at 0.388 kg CO_2/kWh.

It is assumed that the new plants (gas-based) will have a reference efficiency of 52% over the whole period and the replacement of the thermal power plants to gas-fired plants will be made gradually and will be completed in 30 years. The emission factor for year Z is calculated using the following formula:

Z = (30-t)/30*X + t/30*0.388

For 2004, t =0 and for 2034, t=30, X (the corrected CEF for 2004) is calculated as follows:

Plant/Fuel Type	Year 2004				
	Original Generation mix (%)	Corrected generation mix (%)	Generation (Gwh)	Weighted CEF (tCO2/MWh)	Emissions (ktCO2)
Gas & Fuel Oil	37	68.5	22,872	1.014	23,192
Lignite and Hard Coal	63	31.5	10,518	1.128	11,864
Total	100	100	33,390	**1.050**	35,056

Source: MEA-Netherlands (Sept 2002) KPMG Environmental Services (Sept. 2002) US DOE (2004)

The following table presents the CEF from 2004-2034, assuming all thermal power plants will convert to gas-fired power production.

Year	t	X	Z (CEF)
2004	0	1.050	1.050
2005	1	1.050	1.028
2006	2	1.050	1.009
2007	3	1.050	0.984
2008	4	1.050	0.962
2009	5	1.050	0.940
2010	6	1.050	0.918
2011	7	1.050	0.895
2012	8	1.050	0.873
2013	9	1.050	0.851
2014	10	1.050	0.829
2015	11	1.050	0.807
2016	12	1.050	0.785
2017	13	1.050	0.763
2018	14	1.050	0.741
2019	15	1.050	0.719
2020	16	1.050	0.697
2021	17	1.050	0.675
2022	18	1.050	0.653
2023	19	1.050	0.631
2024	20	1.050	0.681
2025	21	1.050	0.587
2026	22	1.050	0.565
2027	23	1.050	0.542
2028	24	1.050	0.520
2029	25	1.050	0.498
2030	26	1.050	0.476
2031	27	1.050	0.454
2032	28	1.050	0.432
2033	29	1.050	0.410
2034	30	1.050	0.388

Source: MEA-Netherlands (Sept 2002) KPMG Environmental Services (Sept. 2002)
US DOE (2004)

At the Project electricity generation output of 5,992 GWh/year from 2008-2012, this option will have the following emission reductions:

Crediting Period	2008	2009	2010	2011	2012
Super-Critical Coal					
Generation (GWh)	5,992	5,992	5,992	5,992	5,992
CEF ($kgCO_2/kWh$)	0.873	0.873	0.873	0.873	0.873
Baseline Option 6					
CEF ($kgCO_2/kWh$)	**0.962**	**0.940**	**0.918**	**0.895**	**0.873**
Difference ($kgCO_2/kWh$)	0.089	0.067	0.045	0.022	0
Emission reductions (kt CO_2)	533	401	270	132	0
Total emission reductions for 2008-2012 (kt CO_2)	1,336				

Source: MEA-Netherlands (Sept 2002)
KPMG Environmental Services (Sept. 2002)
US DOE (2004)

Option 6 would realize a total emission reduction of 1,336 kt CO_2 during the period 2008-2012.

5.2 Identification of the most likely baseline

A summary of the baseline options is shown below:

Option	Total emission reductions/(additions) for 2008-2012 (kt CO_2)	Remarks
1	(6,860)	No Reduction
2	(8,701)	No Reduction
3	(7,148)	No Reduction
4	6,614	Reduction Achieved
5	5,419	Reduction Achieved
6	1,336	Reduction Achieved

Of the baseline options where reductions are achieved

- Option 4 - 3% growth in electricity generation for 2008-2012. Constant generation from hydro (2004-2012) and 2 nuclear plants (2004-2012) are excluded. Coal and oil/gas-fired power plants will provide additional electricity generation requirements. Electricity generation from coal and oil/gas-fired power plants will be replaced by new coal-fired technology.

- Option 5 - Same as Option 4 but takes into account correction for operations at margin.

- Option 6 - the existing coal and oil/gas-fired power plants will gradually switch to natural gas as the only fuel used through to 2030. This option does not include any new coal-fired plant but is included for comparison purposes.

The more substantial emission reductions are achieved under Options 4 and 5, both of which account for the expected 3% growth in electricity demand and take the practical step of making the clean coal JI project directly comparable to replacement of electricity generation from existing coal oil and gas plants.

Option 5 attempts to also take into account the use of gas and oil fired plant at the margin. It is also the more conservative of the two baselines and is therefore the chosen Option.

5.3 Other technologies

It is worthwhile at this point to briefly consider other available advanced coal fired power generation technologies for possible implementation in Romania.

5.3.1 Integrated Gasification Combined Cycle (IGCC).

The use of gasification as the base technology introduces some considerable changes in terms of efficiency and environmental performance. The number of demonstration IGCC plants worldwide is increasing fairly rapidly as technological issues relating to clean up of the syngas and the use of syngas in a gas turbine are resolved.

The largest IGCC currently in operation is less than 400 MW capacity and for the purposes of this document we consider a fluidised bed gasification combined gas and steam cycle system of 300 MW capacity. While the majority of IGCC systems currently operating are based on entrained flow gasification, the low reported calorific value of these lignites suggests there may be difficulties for this technology – it relies on sufficient heat in the gasifier to melt the ash. Provided the lignites are of sufficient reactivity and have a sufficiently high ash fusion temperature they may be better suited to the less expensive fluidised bed- based IGCC system.

The use of a gas turbine to generate electricity, capture of the waste heat from the turbine, and use of that heat to raise steam for use in a steam turbine offers the prospect of efficiencies of around 50%. Currently, levels of 43 to 45% are being increasingly reported for entrained flow slagging gasifier-based systems. We have assumed 45% net efficiency for the proposed fluidised bed based plant.

Option 5 will be applicable for an IGCC scenario, since its emissions factor will be 0.815 $kgCO_2$ per kWh. Staying with our 57% utilisation figure, the IGCC electricity generation output will be limited to 1,498 GWh/year from 2008-2012 and will achieve the following emission reductions:

Crediting Period	2008	2009	2010	2011	2012
IGCC plant					
Generation (GWh)	1,498	1,498	1,498	1,498	1,498
CEF ($kgCO_2$/kWh)	0.815	0.815	0.815	0.815	0.815
Baseline Option 5					
CEF ($kgCO_2$/kWh)	1.052	1.053	1.054	1.055	1.055
Difference ($kgCO_2$/kWh)	0.237	0.238	0.239	0.240	0.240
Emission reductions (kt CO_2)	355	357	358	360	360
Total emission reductions for 2008-2012 (kt CO_2)			1,790		

5.3.2 Circulating Fluidised Bed Combustion (CFBC).

A more widely available and mature technology than IGCC, it has efficiencies comparable to, or slightly above those of sub-critical plant and has a "built-in" de-SO_x and de-NO_x capability. It can reduce sulphur emissions up to 75% using in bed limestone injection and because it runs at lower temperatures than pulverised coal units typically generates significantly lower levels of NO_x. It should be noted that for this, and the following fluidised bed combustion based technologies, it is important that the ash does not undergo melting. With the high ash contents of the lignite feedstock, this issue is of particular importance.

For the purpose of this study a plant size of 250 MW is selected. Since this plant is calculated to have an emission factor of 0.940 and its output (at 57% utilisation) is 1,248 GWh/year from 2008-2012, under Option 5, the plant will achieve the following emission reductions:

Crediting Period	2008	2009	2010	2011	2012
CFBC plant					
Generation (GWh)	1,248	1,248	1,248	1,248	1,248
CEF ($kgCO_2$/kWh)	0.940	0.940	0.940	0.940	0.940
Baseline Option 5					
CEF ($kgCO_2$/kWh)	1.052	1.053	1.054	1.055	1.055
Difference ($kgCO_2$/kWh)	0.112	0.113	0.114	0.115	0.115
Emission reductions (kt CO_2)	140	141	142	143	143
Total emission reductions for 2008-2012 (kt CO_2)			709		

5.3.3 Pressurised Fluidised Bed Combustion (PFBC).

This technology also features the fuel flexibility of IGCC and, like atmospheric circulating fluidised bed technology, has a "built-in" de-SO_x and de-NO_x capability. It has the advantage over CFBC of higher thermal efficiency due to the inclusion of the combined gas and steam cycle. The gas turbine cycle typically generates about 20% of the electrical output and also supplies air to the fluidised bed assembly. Elevated pressures and temperatures produce a high temperature gas stream that drives the gas turbine and steam generated from the heat in the fluidised bed is sent to a steam turbine.

For the purpose of this study a plant size of 250 MW is also selected. Its electricity generation output will also be limited to 1,248 GWh/year at 43% net efficiency from 2008-2012. Under Option 5, the plant will achieve the following emission reductions:

Crediting Period	2008	2009	2010	2011	2012
PFBC plant					
Generation (GWh)	1,248	1,248	1,248	1,248	1,248
CEF ($kgCO_2/kWh$)	0.853	0.853	0.853	0.853	0.853
Baseline Option 5					
CEF ($kgCO_2/kWh$)	1.052	1.053	1.054	1.055	1.055
Difference ($kgCO_2/kWh$)	0.199	0.200	0.201	0.202	0.202
Emission reductions (kt CO_2)	249	250	251	252	252
Total emission reductions for 2008-2012 (kt CO_2)	1,254				

5.3.4 Pressurised Circulating Fluidised Bed Combustion (PCFBC).

Similar considerations as PFBC will apply to this technology. It has higher efficiency than a circulating fluidised bed system because of the use of the combined gas/steam cycle and retains the "in-built" ability to reduce SO_x and NO_x levels.

Again, a plant size of 250 MW is selected. Its electricity generation output will also be limited to 1,248 GWh/year at 43% net efficiency from 2008-2012. Under Option 5, the plant will achieve the following emission reductions:

Crediting Period	2008	2009	2010	2011	2012
PCFBC plant					
Generation (GWh)	1,248	1,248	1,248	1,248	1,248
CEF ($kgCO_2/kWh$)	0.853	0.853	0.853	0.853	0.853
Baseline Option 5					
CEF ($kgCO_2/kWh$)	1.052	1.053	1.054	1.055	1.055
Difference ($kgCO_2/kWh$)	0.199	0.200	0.201	0.202	0.202
Emission reductions (kt CO_2)	249	250	251	252	252
Total emission reductions for 2008-2012 (kt CO_2)	1,254				

5.4 Summary of emission reductions for Technology options

The emission factors of the above technology options for the crediting period (2008-2012) are summarized below:

	Technology		Super-Critical	CFBC	PFBC	CFBC	IGCC
	Net Efficiency	%	42	39	43	43	45
	Size	MW	2 x 600	250	250	250	300
	Generation	GWh	5,992	1,248	1,248	1,248	1,498
	Emissions coefficient	kg CO_2/kWh_e	0.873	0.940	0.853	0.853	0.815
Option No.	Condition	Methodology	Total emission reductions (kt CO_2) (2008-2012)				
5	3% growth in electricity generation for 2008-2012. Constant generation from hydro (2004-2012) and 2 nuclear plants (2004-2012) are excluded. Coal and oil/gas-fired power plants will provide additional electricity generation requirements. Electricity generation from coal and oil/gas-fired power plants will be replaced by new coal-fired technology. Correction applied to take account of the fact that gas and oil fired plant are more frequently operated at the margin.	Ministry of Economic Affairs of the Netherlands Guidelines, Volume 2a, Annex B, 2002)	5,419	709	1,254	1,254	1,790

6.0 CREDITING TIME

Start date of the project	2008
Lifetime of the project	25 years
Crediting time of the project (only relevant if the project crediting time will end before 2012)	Five years based on commitment period (2008-2012)

7.0 MONITORING PLAN

8.1 Data collection to monitor emissions from the project activity (including possible leakage)

ID number	Data type	Data variable	Unit	Measured, calculated or estimated	Recording & archiving method (electronic/ paper)	Registration frequency

8.2 Measuring methods to be used

Measurement method	Institution/function to execute measurements	Calibration method	Calibration frequency

8.3 Methods for quality control and quality assurance procedures

8.4 Statistical techniques for determining relevant factors

9.0 STAKEHOLDER COMMENTS

10.1 Process of gathering stakeholder comments and involving the stakeholders

10.2 Summary of comments received and the names of stakeholders who gave their comments

10.3 Actions taken

11.0 ENVIRONMENTAL IMPACT

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Annex 1b

Clean Development Mechanism Project Design Document for Clean Coal Technologies in China

Preamble:

The following document considers hypothetical case studies using the UNFCCC guidelines for Project Design Documents for CDM projects. The CDM country is China and the document relies significantly on information and data from the World Bank Report "Clean Development Mechanism in China" produced in 2004.

The template for CDM PDD documents as approved by the CDM Executive Board is followed throughout. Some of the sections cannot be addressed in a purely hypothetical case study. In those instances, the headings for these sections are retained but the section left blank.

A. General description of project activity

This is a hypothetical case study of a proposed super-critical coal-fired power plant to be constructed in one of the provinces in China. Power data were based on available statistics from the State Power Grid Corporation of China, IPCC figures, and information from other CDM studies made in China by other entities such as the World Bank. Other clean coal technologies including Integrated Gasification Combined Cycle (IGCC) Circulating Fluidised Bed Combustion (CFBC) Pressurised Fluidised Bed Combustion (PFBC) and Pressurised Circulating Fluidised Bed Combustion (PCFBC) are also considered for comparison purposes.

A.1 Title of the project activity:

Henan Super-Critical Coal-Fired Power Project (hypothetical)

A.2. Description of the project activity:

It is proposed that the super-critical coal-fired power plant be constructed in Henan Province, China. Henan province is located in Central China and is covered by the Henan Provincial Power Network of the Central China Regional Grid.

The plant will consist of 2 x 600 MW generating units for a total installed capacity of 1,200 MW. Its construction and subsequent operation is considered to be of great importance to China's domestic manufacturing level and restructuring of its electric industry.

Assumed parameters of the super-critical plant are shown in the following table.

Main Parameters of the Henan Super-Critical Coal-Fired Power Plant

Base year (for technical, economic data): 2004

Technical data (net)*	
Unit Capacity, MW	600
No. of units	2
Total Installed capacity (MW)	1,200
% Utilization (per year)	63
Full load utilization hours (h/year)	5,519
Energy generation (GWh/year)	6,623
Fuel consumption (million tonnes/yr), Coal (ideal)	0.969
Net efficiency (%)	42
Fuel consumption (million tonnes/yr), Coal (actual)	2.308
Designed life period (years)	25
Carbon content of fuel coal (%)	64.0

Heating value of coal used (MJ/kg)	24.6
Heating value of standard coal, MJ/kg	29.307
Economic data	
Total capital cost (US$ Million)**	1,479
Direct capital cost (at US$1,060/kW)	*1,272*
Indirect capital cost (US$/kW), 16.3% of DCC	*207*
Fuel costs (US$ million)***	115
Fuel costs (US$/$GWh_f$)	0.0174
Interest rate (% p.a.)	6
Lifetime (years)	25
Crediting period (years)	7(+7+7)[1]
Activity period (years)	25
Labour costs (US$ Millions/year)****	37
Maintenance costs (US$ millions/year)****	74
Environmental data	
CO_2 emission factor ($kgCO_2/kWh_f$)	0.818

Note: 1 US$ - 8.2816 RMB (China Yuan Renminbi) (2004)
* World Bank, et. al. (June 2004)
** Scott & Nilsson (IEA, 1999)
*** Coal cost = $50/tonne
**** Tavoulares and Charpentier (World Bank, 1995)
Direct capital cost = Plant facility capital + General facility capital
Indirect capital cost = Engineering & Administration + Contingencies + Capital costs during construction + Commissioning cost + Inventory capital = 16.4% of Direct capital cost
Labour cost = 3% of Direct capital cost
Maintenance costs = 6% of direct capital cost

Similarly, we assumed the following parameters for the other coal plant technologies:

Base year (for technical, economic data): 2004

	CFBC	PFBC	PCFBC	IGCC
Technical data (net)*				
Unit Capacity, MW	250	250	250	300
No. of units	1	1	1	1
Total Installed capacity (MW)	250	250	250	300
% Utilization (per year)	63	63	63	63
Full load utilization hours (h/year)	5,519	5,519	5,519	5,519
Energy generation (GWh/year)	1,380	1,380	1,380	1,656
Fuel consumption (million tonnes/yr), Coal (ideal)	0.202	0.202	0.202	0.242
Net efficiency (%)	39	43	43	45
Fuel consumption (million tonnes/yr), Coal (actual)	0.518	0.470	0.470	0.538
Designed life period (years)	25	25	25	25
Carbon content of fuel coal (%)	64.0	64.0	64.0	64.0
Heating value of coal used (MJ/kg)	24.6	24.6	24.6	24.6
Heating value of standard coal, MJ/kg	29.307	29.307	29.307	29.307
Economic data				
Total capital cost (US$ Million)**	337	347	347	475
Direct capital cost (at US$ Million)	*290*	*298*	*298*	*408*
@ Direct capital cost (at US$/kW)	*1,160*	*1,190*	*1,190*	*1,360*

[1] First crediting period, to be renewed, two more times (maximum of 21 years), subject to determination/validation of project baseline at beginning of each renewal period.

Indirect capital cost (US$ Million), 16.3% of DCC	*47*	*49*	*49*	*67*
Fuel costs (US$ million)*	25.9	23.5	23.5	26.9
Fuel costs (US$/$GWh_f$)***	0.019	0.017	0.017	0.016
Interest rate (% p.a.)	6	6	6	6
Lifetime (years)	25	25	25	25
Crediting period (years)	7(+7+7)	7(+7+7)	7(+7+7)	7(+7+7)
Activity period (years)	25	25	25	25
Labour costs (US$ Millions/year)	41	42	42	48
Maintenance costs (US$ millions/year)	82	84	84	96
Environmental data				
CO_2 emission factor (kgCO_2/kWh_f)	0.881	0.799	0.799	0.763

Note: 1 US$ - 8.2816 RMB (China Yuan Renminbi) (2004)
*   World Bank, et. al. (June 2004)
** Scott & Nilsson (IEA, 1999)
*** Coal cost = $50/tonne
**** Tavoulares and Charpentier (World Bank, 1995)
Direct capital cost = Plant facility capital + General facility capital
Indirect capital cost = Engineering & Administration + Contingencies + Capital costs during construction + Commissioning cost + Inventory capital = 16.4% of Direct capital cost
Labour cost = 3% of Direct capital cost
Maintenance costs = 6% of direct capital cost

A.3. Project participants:

The following participants are engaged in this CDM project case study.

Project host	Henan Corporation (Hypothetical name only)
Name of the company:	Henan Generation Company
Street, No.	123 ABC
Town, district, country	Beijing, China
Local power supply company	
Name of the company	Henan Power Company (Hypothetical name only)
Street, No.	456 DEF
Town, District, Country	Henan Province, China
Project design company:	
Name of the company	Henan Power Design Company (Hypothetical name only)
Street, No.	789 GHI
Town, district, country	Henan Province, China

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

A.4.1.1 Host Party(ies):

Henan Power Group (Hypothetical name only)

A.4.1.2 Region/State/Province etc.:

Henan Province (Hypothetical name only)

A.4.1.3 City/Town/Community etc:

Henan City (Hypothetical name only)

A.4.1.4 Detail of physical location, including information allowing the unique identification of this project activity:

The project will be located in Henan Province, Central China. The location map of Henan is shown below.

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

The proposed project activity can be considered under category: Power production: new installation using energy efficiency improvement initiative to reduce CO_2 emissions.

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

The project will utilize super-critical pulverised coal combustion technology. It will be supported by Chinese central government as an attempt to localize super-critical technology expertise in the country, especially in the fields of equipment design and manufacturing.

A.4.4 Brief explanation of how the anthropogenic emissions of anthropogenic greenhouse gas (GHGs) by sources are to be reduced by the proposed CDM project activity, including why the emission reductions would not occur in the absence of the proposed project activity, taking into account national and/or sectoral policies and circumstances:

Super-critical thermal power generation technology for coal is one of the new technologies being promoted in the power industry plan in China. However, without proper technology and financial support or assistance, the Henan Super-Critical Coal-Fired Power Plant will not be considered for implementation in China. If the plant is not implemented, the government will instead construct 2 x 600 MWe conventional coal-fired thermal generation units based on sub-critical technology to meet the increasing demand for electricity in Henan province.

A review of the current five-year power plan for Henan province showed that either 300 MWe or 600 MWe sub-critical thermal units will be the main types of power plant to be constructed in the coming ten years. (CDM in China, World Bank-2004). The failure to proceed with the construction of the proposed 2 x 600 MW super-critical plant means that an annual emission reduction equivalent of approximately 940,000 tonnes of CO_2 will not occur. In other words, this environmental benefit is additional to the business as usual scenario ('the baseline generation").

A.4.5. Public funding of the project activity:

There is no public funding committed for this project.

B. Application of a baseline methodology

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

CDM Executive Board Approved Baseline Approaches (Source: UNFCCC CDM website - http://cdm.unfccc.int)

(a) Paragraph 48 (a) - Existing actual or historical emissions, as applicable.

(b) Paragraph 48 (b) - Emissions from a technology that represents an economically attractive course of action taking into account barriers to investment, or

(c) Paragraph 48 (c) - The average emissions of similar project activities undertaken in the previous five years, in similar social, economic, environmental and technological circumstances, and whose performance is among the top 20% of their category

B.1.1 Justification of the choice of the methodology and why it is applicable to the project activity

Henan Province has severe power shortages and is considering the fastest way possible for expanding its power system. Sub-critical thermal units of 600MWe are commercially available and will be easier and faster to construct than other coal based power technologies. Sub-critical coal power generation is one of the most economically attractive technologies for power supply expansion.

The study takes into account relevant national and/or provincial policies and circumstances, such as sectoral conditions, fuel availability, power sector expansion, technological and operational improvement, economic growth and social development.

Four (4) baselines (options 1,1a, 2 and 3 see below) were constructed to compare the performance of the sub-critical thermal units according to the above three methodologies.

The final option selected was based on the lowest emissions savings estimate, and also considered the robustness, transparency, and conservativeness of the data.

B.2. Description of how the methodology is applied in the context of the project activity:

Basic assumptions:

1. The starting point of the baseline is the current situation (Year 2004).

2. The CDM Project will be operational by 2006 and its output will remain constant during the crediting period.

3. Rules, guidelines and procedures developed by the CDM EB were reviewed and incorporated in the process.

4. Total generation in Henan province for 2004 is 65,540 GWh, 832 GWh is hydro (1.27%), natural gas is 1,393 GWh (2.12%) and coal plants are 63,316 (96.61%).

5. We identified the following options within the CDM Executive Board Approved Baseline Approaches:

   a) Paragraph 48 (a) - Existing actual or historical emissions, as applicable:

      - Option 1 - 5% growth in capacity. Existing generation mix from coal, hydro and gas remains constant

      - Option 1A - 5% growth in capacity. Existing generation mix remains constant, hydro and gas efficiency fixed, coal plant efficiency improvement of 0.3% p. a. (absolute)

   b) Paragraph 48 (b)

      - Option 3 – Most economically attractive thermal technology

   c) Paragraph 48 (c)

      - Option 2 - Built Margin – Recent Additions only

The above options were used to derive the following baseline scenarios:

B.2.1 Option 1

China has its Five-Year Power Plan to develop new power plants to meet increased energy demand and solve the shortage of its electricity supply. A conservative annual growth of 5% in the power requirements of the province is considered for this option. (CDM in China, World Bank- 2004).

The existing generation mix (2004) from coal, hydro and gas, and their GHG emissions (if any) will be at the same level during the first crediting period (2006-2012).

Under this option, the CO_2 emission factor for each crediting period will be 1.102 ($kgCO_2/kWh$).

B.2.2 Option 1A

The same conditions in Option 1 were considered together with historical increase of thermal plant efficiency in China. Records showed that there is a continuing improvement in combustion efficiency of coal power plants, brought about by advancement in technology (i.e. retrofitting, etc.) and improved knowledge and expertise in plant operation. The historical record of 0.3% per annum increases in thermal efficiency of the coal plants is assumed to continue for the first crediting period.

Under this option, the CO_2 emission factors will be

- 1.048 $kgCO_2/kWh$ for the 1st crediting period
- 0.983 $kgCO_2/kWh$ for the 2nd crediting period
- 0.926 $kgCO_2/kWh$ for the 3rd crediting period
- 0.972 kgCO2/kWh weighted average

B.2.3 Option 2

This method uses the average emissions of similar power plants built in the previous five years, in similar circumstances, and whose performances are among the top 20% of their category. It also assumes that the technical and economic conditions for choosing capacity do not change significantly.

In the last five years, the following coal-fired generation units (with their respective emission figures) were built in the province:

Plant	Total Capacity (MW_e)	gCE/kWh	Net Emission factor $kgCO_2/kWh$	Plant combustion Efficiency
Anyang 9 & 10	600	365	1.010	33.65%
Yichuan 2	500	376	1.041	32.67%
Shanxian County Thermal	110	410	1.135	29.96%
Xuchang Longgang	700	374	1.035	32.85%
Xinyang 1 & 2	600	369	1.021	33.29%
Nanyang 5	25	778	2.153	15.79%
Pingdingshan Sanhe 1	25	581	1.608	21.14%

Source: "Clean Development Mechanism in China: Taking a Proactive and Sustainable Approach" – Annex 2 – CDM Project Design Document 2nd Phase Huaneng Qinbei, Super-critical Coal-Fired Power Pant, Henan, China, World Bank, et. al. (June 2004)

We chose Anyang 9 & 10 and Xinyang 1 & 2 as the two plants with the lowest net emission factor of 1.010 $kgCO_2/kWh$ and 1.021 $kgCO_2/kWh$, respectively.

The weighted CO_2 emission factor for these two plants for all three crediting periods is 1.016 $kgCO_2/kWh$.

B.2.4 Option 3 - Most Economically Attractive Thermal Technology

There are no 600MWe sub-critical thermal units constructed or planned for construction in Henan Province. Similar plants, however, were operational in other provinces in the last several years. With efficiency improved and cost reduced, this technology could be a good option for the baseline determination for the CDM project.

Plant	Location	Total Capacity (MW_e)	gCE/kWh	Net Emission factor $kgCO_2/kWh$	Plant combustion Efficiency
Beilun 2	Beilun	1800	0.331	0.925	36.74%
Wujing 2 (Unit 1)	Shanghai	600	0.353	0.987	34.45%
Wujing 2 (Unit 2)	Shanghai	600	0.348	0.973	34.95%
Datang Panshan 1	Tianjin	600	0.394	1.102	30.87%
Harbin 3rd (Units 3&4)	Heilongjiang	1200	0.350	0.979	34.75%
Yuanbaoshan 3	Inner Mongolia	600	0.362	1.012	33.59%
Yangzhou 2nd	Jiangsu	1200	0.335	0.939	36.30%
Pingyu	Anhui	1200	0.345	0.965	35.25%
Weighted Average			347	0.960	35.40%

Source: "Clean Development Mechanism in China: Taking a Proactive and Sustainable Approach" – Annex 2 – CDM Project Design Document 2nd Phase Huaneng Qinbei, Super-critical Coal-Fired Power Pant, Henan, China, World Bank, et. al. (June 2004)

Under this option, the weighted CO_2 emission factor for all the above power plants for all three crediting periods is 0.960 $kgCO_2/kWh$.

This is the favoured option for the first crediting period. Under this baseline, the emissions savings from the proposed 2 x 600 MW super-critical plant will be 940,000 tonnes of CO_2 per annum during the first crediting period.

B.2.5 Other technologies

It is worthwhile at this point to briefly consider other available advanced coal fired power generation technologies.

B.2.5.1. Integrated Gasification Combined Cycle (IGCC).

The use of gasification as the base technology introduces some considerable changes in terms of efficiency and environmental performance. The number of demonstration IGCC plants worldwide is increasing fairly rapidly as technological issues relating to clean up of the syngas and the use of syngas in a gas turbine are resolved.

The use of a gas turbine to generate electricity, capture of the waste heat from the turbine, and use of that heat to raise steam for use in a steam turbine offers the prospect of efficiencies of around 50%. Currently levels of 43 to 45% are being increasingly reported and we have assumed 45% net efficiency for the purposes of this document.

The sulphur in the feed coal emerges from the gasifier in the form of H_2S – and as such is more readily removed from the product gas stream than SO_2 is removed from combustion flue gas. Most of the sulphur removal technologies are carried out after the gas has been cooled. Higher efficiencies are achievable with hot gas desulphurisation but these technologies remain in the demonstration stage.

The largest IGCC currently in operation is less than 400 MW capacity and for the purposes of this document we consider an entrained flow slagging gasification combined gas and steam cycle system of 300 MW capacity. The majority of IGCC systems currently operating are based on the entrained flow gasification technology.

Using the Option 3 baseline value of 0.960 kg CO_2 per kWh along with the calculated emission factor for the IGCC plant of 0.763 kg CO_2 per kWh gives an estimated reduction for this 300 MW plant of 326,000 tonnes of CO_2 per annum during the first commitment period.

B.2.5.2.Circulating Fluidised Bed Combustion (CFBC).

A more widely available and mature technology than IGCC, it has efficiencies comparable to, or slightly above those of sub-critical plant and has a "built-in" de-SO_x and de-NO_x capability. It can reduce sulphur emissions up to 75% using in bed limestone injection and because it runs at lower temperatures than pulverised coal units typically generates significantly lower levels of NO_x.

For the purposes of this study a plant size of 250 MW with a net efficiency of 39% is selected Based on these assumptions and using the emission factor for Option 3 of 0.960 and the calculated emission factor of 0.881kg CO_2 per kWh for this technology means 109,000 tonnes of CO_2 will be reduced per annum.

B.2.5.3. Pressurised Fluidised Bed Combustion (PFBC).

This technology also features fuel flexibility of IGCC and, like atmospheric circulating fluidised bed technology, has a "built-in" de-SO_x and de-NO_x capability. It has the advantage over CFBC of higher thermal efficiency due to the inclusion of the combined gas and steam cycle. The gas turbine cycle typically generates about 20% of the electrical output and also supplies air to the fluidised bed assembly. Elevated pressures and temperatures produce a high temperature gas stream that drives the gas turbine and steam generated from the heat in the fluidised bed is sent to a steam turbine.

For the purposes of this study a plant size of 250 MW is selected and a net efficiency of 43% is assumed. Based on these assumptions and an emission factor of 0.799 kg CO_2 per kWh leads to an annual reduction of 222,000 tonnes of CO_2 .

B.2.5.4. Pressurised Circulating Fluidised Bed Combustion (PCFBC).

Similar considerations apply to this technology. It has higher efficiency than a circulating fluidised bed system because of the use of the combined gas/steam cycle and retains the "in-built" ability to reduce SO_x and NO_x levels.

Again assuming a 250 MW sized unit is built with a net efficiency of 43% leads to a reduction of 222,000 tonnes of CO_2 per annum for this plant.

B.2.7. Summary of options

The emission factors of the above options for the first crediting period (2006-2012) are summarized below:

	Technology		Super-Critical	CFBC	PFBC	PCFBC	IGCC
	Efficiency	Net Efficiency	42	39	43	43	45
	Size	MW	2 x 600	250	250	250	300
	Emissions coefficient	kg CO_2/kWh_e	.818	.881	.799	.799	.763
Option No.	Condition	Methodology	Emissions coefficient				
1	5% growth in capacity. Existing generation mix from coal, hydro and gas to be constant	Baseline Approach CDM EB - Paragraph 48 (a)	1.102	1.102	1.102	1.102	1.102
1a	5% growth in capacity. Existing generation mix to be constant hydro and gas fixed efficiency, coal plant efficiency improvement of 0.3% p. a. (absolute)	Baseline Approach CDM EB - Paragraph 48 (a)	1.048	1.048	1.048	1.048	1.048
2	Recent additions only – built margin	Baseline Approach CDM EB - Paragraph 48 (c)	1.016	1.016	1.016	1.016	1.016
3	Most economically attractive thermal technology	Baseline Approach CDM EB - Paragraph 48 (b)	**0.960**[2]	**0.960**	**0.960**	**0.960**	**0.960**
	Emissions reductions (Baseline – Technology)	$KgCO_2/kWh$	0.142	0.079	0.161	0.161	0.197
		Ktonnes of CO_2	940	109	222	222	326

[2] Sub-critical coal at 35.4%

The best baseline methodology options for each technology are shown in Green. Option 3 is chosen as the baseline for all three commitment periods.

B.3. Description of how the anthropogenic emissions of GHG by sources are reduced below those that would have occurred in the absence of the registered CDM project activity:

Super-critical thermal generation technology is listed as one of the new technologies for promotion in the Five-Year Plan of Power Industry in China. Its technology is as follows:

"Coal is first ground into fine particles and injected with a proportion of the combustion air ("primary air") into the lower part of a combustion chamber using an array of injectors ("burners") and ignited using oil or gas flames. The particles burn in suspension, creating flames and releasing heat into the combustion chamber. The rest of the combustion air ("secondary air") is usually supplied around the injector, mixing with the burning coal particles further away from the chamber wall, to provide additional oxygen to complete combustion. The heat released into the combustion chamber is transferred, mainly by radiation and convection, to the water tubes located in the walls of the combustion chamber. Hot gases move upwards and the super-heater tubes located near the top of the combustion chamber extracts further heat during the process. Finally, the economiser extracts further heat, which will heat the water before it enters the boiler tubes and the flue gases are vented to the atmosphere via a stack".

During the super-critical technology process, the main steam is at a pressure larger than 24 MP_a and temperature around 538/566°C. Currently, pulverised coal-fired supercritical steam cycle plants with steam pressure of 240 bars, temperature of 540°C, and unit sizes of 400-900 MW_e were developed and introduced mainly in Europe and the USA. Such plant can achieve generation efficiencies (LCV basis) of up to around 42%. This improvement in efficiency results in reduced emissions of CO_2.

Similarly, the other technologies (IGCC, PFBC and PCFBC) achieve emission reductions through improved efficiency of plant.

B.4. Description of how the definition of the project boundary related to the baseline methodology selected is applied to the project activity:

Direct GHG emissions can be produced from:

- Combustion of coal, and
- Combustion of diesel during plant start-up

During start-up of the thermal generation unit, diesel is used in the combustor for firing of the pulverized coal. This limited amount of diesel and its GHG emission may be considered insignificant as compared to the large amount during combustion of coal. It is then assumed that the CO_2 emission during diesel combustion is negligible for the CDM super-critical and baseline conventional sub-critical units.

Indirect GHG emission sources for the CDM case are produced during the following processes:

- Manufacture of equipment and building materials
- Transport of equipment and building materials
- Manufacture of power transmission lines
- Construction of power transmission lines
- Construction of power house

These GHG emissions, however, will not be evaluated since:

- They are not measurable and cannot be monitored on a cost effective basis
- They are negligible for either the CDM case or the baseline and no significant emission reduction or change is induced by the CDM activity.

The CDM Project Boundary is selected as the physical boundary of the power plant, whereas the system boundary is identified as the provincial power system.

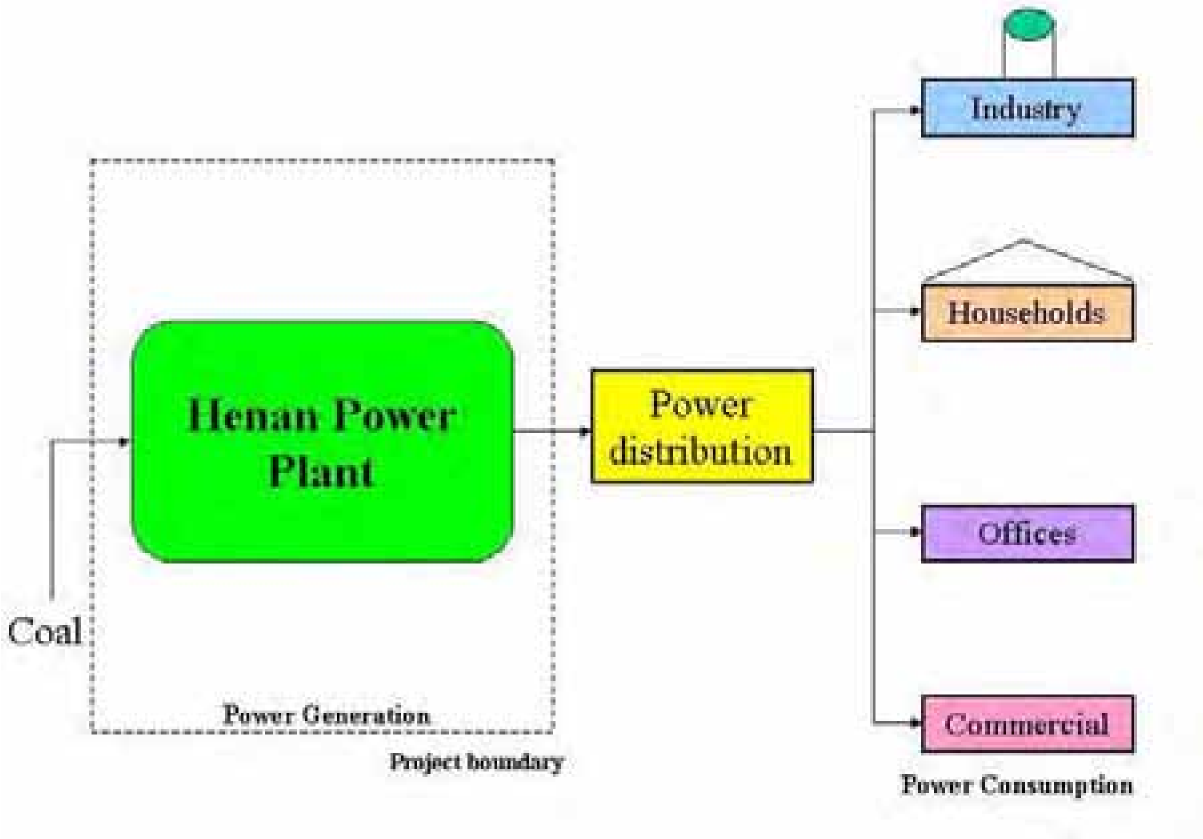

Figure 2 – Project boundary of CDM case

Source: "Clean Development Mechanism in China: Taking a Proactive and Sustainable Approach" – Annex 2 – CDM Project Design Document 2nd Phase Huaneng Qinbei, Super-critical Coal-Fired Power Pant, Henan, China, World Bank, et. al. (June 2004)

The project boundary accommodates all the direct emission sources of GHGs identified in the CO_2 emission from coal and diesel combustion.

B.5. Detailed baseline information, including the date of completion of the baseline study and the name of person(s)/entity(ies) determining the baseline:

B.6.1 Date of completing the final draft of this baseline section (DD/MM/YYYY):

B.6.2 Name of person/entity determining the baseline:

C. Duration of the project activity/Crediting period

C.1 Duration of the project activity:

25 years

C.1.1. Starting date of the project activity:

01/01/2006

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

25 years

C.2 Choice of crediting period and related information:

C.2.1. Renewable crediting period:

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

01/01/2006

C.2.1.2. Length of the first crediting period:

7 years

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

C.2.2.2. Length:

D. Application of a monitoring methodology and plan:

D.1. Name and reference of approved monitoring methodology applied to the project activity:

The proposed monitoring methodology will be done on a periodic basis, rather than real-time monitoring. The monitoring is dependent on the operational records of the CDM project, as well as comparison with similar generation units in China and abroad.

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

Justification of this choice is based on the following considerations:

- Monitoring of the fuel coal consumption and combustion in the generation process will build up an accurate monitoring on CO_2 emission.
- In China, there is a standard procedure to make records of performance of the power units 24 hours a day, 7 days a week. These statistics are well kept by the industrial administrative in the region/province.
- Physical and chemical analyses of coal and records on coal consumption are part of the routine activities at each thermal power plant.
- Statistics can be gathered for both the CDM and baseline cases..

D.2.1. Option 1: Monitoring of the emissions in the project scenario and the baseline scenario:

D.2.1.1. Data to be collected in order to monitor emissions from the project activity, and how this data will be archived:

ID	Data type	Data variable	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/paper)	For how long is archived data to be kept?	Comment
1	Carbon content of fuel coal	CC_c	%	M	Once every lot	100%	P	2y after the crediting period	
2	Annual consumption of fuel coal	ACC_{CDM}	Tonne/y	M	Once every year	100%	P	2y after the crediting period	
3	Net electricity generation	EG_{net}	KWh/y	M	Once every year	100%	P	2y after the crediting period	
4	Combustion efficiency of the boilers	CE	%	M	Once every year	100%	P	2y after the crediting period	
5	Heat value of the fuel coal	HV_C	(GWh_f/kg)	M	Once every year	100%	P	2y after the crediting period	

Source: "Clean Development Mechanism in China: Taking a Proactive and Sustainable Approach" – Annex 2 – CDM Project Design Document 2nd Phase Huaneng Qinbei, Super-critical Coal-Fired Power Pant, Henan, China, World Bank, et. al. (June 2004)

D.4. Potential sources of emissions which are significant and reasonably attributable to the project activity, but which are not included in the project boundary, and identification if and how data will be collected and archived on these emission sources.

None.

D.5 Name of person/entity determining the monitoring methodology:

E. Estimation of GHG emissions by sources:

E.1. Estimate of GHG emissions by sources:

The formula for the CO_2 is based on the IPCC emission factor set at

The formula for CO_2 emission factor from coal combustion (EF_c) is:

$$EF_c = \frac{CR/ \times CC_c \times CE \times 44}{HV_C \times 12}$$

(in kg-CO_2/kWh_f)

Where,

CR = Conversion rate of electricity = 3600 kJ/kWh
HV_c = Heating value of coal = 24,600 kJ/kg
CC_c = Carbon content of coal = 64.0 %
CE = Combustion efficiency = 100 % for baseline and CDM case (ideal case)

So:

$$EF_c = \frac{3{,}600 \text{ KJ/kWh/} \times 64.0\% \times 100\% \times 44}{24{,}600 \text{ kJ/kg} \times 12}$$

$$= 0.3434 \text{ kg } CO_2/kWh_f$$

The formula for annual CO_2 emission in the CDM project (AE_{CDM}) is:

$$AE_{CDM} = \frac{EF_c \times ACC_{CDM}}{1000}$$

Where:

EF_c = CO_2 emission factor from coal combustion (from previous computation)
= 0.3434 kg CO_2/kWh_f

ACC_{CDM} = Annual coal consumption for CDM project generation (the super-critical generation)
= 1.577×10^{10} kWh_f

Therefore:

$$AE_{CDM} = \frac{(0.3434 \text{ kg } CO_2/kWh_f)(1.577\times10^{10} \text{ } kWh_f)}{1000}$$

$$= 5.415 \times 10^6 \text{ tonnes } CO_2/y$$

E.2 Estimated leakage:

There is no leakage identified in this CDM project.

E.3 The sum of E.1 and E.2 representing the project activity emissions:

AE_{CDM} = 5.415×10^6 tonnes CO_2/y

E.4 Estimated anthropogenic emissions by sources of greenhouse gases of the baseline:

Emission of CO_2 of the baseline is the averaged level for 600 MW sub-critical thermal units existing in similar power systems with the same electricity production generated by the two super-critical units of Henan.

The formula for the annual amount of CO_2 emission for the baseline, AE_B (in tonnes CO_2/y) is:

$AE_B = (EF_C) \times (ACC_B)$

Where:

EF_C = CO_2 emission factor from coal combustion (from previous computation)

= 0.3434 kg CO_2/kWh_f

ACC_B = Annual coal consumption for baseline plant generation = 1.851×10^{10} kWh_f

Therefore:

$AE_B = (0.3434 \text{ kg } CO_2/kWh_f) \times (1.851 \times 10^{10} \text{ } kWh_f)/1000 = 6.355 \times 10^6$ tonnes CO_2/y

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

Annual CO_2 emission reduction ($ER_{/yr}$ will be:

$ER_{/yr} = AE_B - AE_{CDM} = 6.355\times10^6 - 5.415\times10^6 = 0.940 \times10^6$ tonnes CO_2/y

For the first 7-year crediting period, the total emission reduction (ER_T) is:

$ER_T = ER_{/yr} \times 7 = 0.940 \times10^6\times7 =6.580 \times 10^6$ tonnes CO_2

The CO_2 emission will be reduced by around 6.6 million tonnes through this CDM project activity for the first 7-year crediting period.

F. Environmental impacts

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

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

None

G. Stakeholders comments

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

Stakeholders are parties or people who have influence on the project, or are involved in the process or are affected by the project. The following stakeholders are identified and their respective functions, duties and responsibilities are given below:

- Governments
    - o Central government
    1. Review and approval of the project design report
    2. Review and approval of the environmental impact assessment report
    3. Approval of the construction
    4. Appointment of the power plant as the demonstrative project of localization of super-critical technology
    5. Approval of the construction of specialized railway for the plant
    6. Approval of the water resource evaluation report
    7. Approval of the seismic security evaluation report

    - o Provincial government
    1. Submission of the project proposal
    2. Submission of the feasibility study report and other technical documents
    3. Approval of the water use and land requisition

    - o City government
    1. Approval of the land use for ash storage

- Partners
    - o Coal suppliers
    - o Banks

- Residents around the site

These stakeholders are involved in the process of the feasibility study and approval procedures.

G.2. Summary of the comments received:

Comments from and interests of the different stakeholders:

- Governments
    - o Central government
    - o Provincial government and City government

- Partners
    - o Coal suppliers
    - o Banks

- Residents around the site

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

REFERENCES

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World Bank, et. al. (June 2004), "Clean Development Mechanism in China: Taking a Proactive and Sustainable Approach"

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	
Street/PO Box:	
Building:	
City:	
State/Region:	
Postfix/ZIP:	
Country:	
Telephone:	
FAX:	
E-Mail:	
URL:	
Represented by:	
Title:	
Salutation:	
Last Name:	
Middle Name:	
First Name:	
Department:	
Mobile:	
Direct FAX:	
Direct tel:	
Personal E-Mail:	

Annex 2

INFORMATION REGARDING PUBLIC FUNDING: