PDD OF CDM COGEN PROJECT

Pakarab Fertilizers Ltd.
Multan; Pakistan

CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-PDD)
Version 03 - in effect as of: 28 July 2006

CONTENTS

A. General description of project activity

B. Application of a baseline and monitoring methodology

C. Duration of the project activity / crediting period

D. Environmental impacts

E. Stakeholders' comments

Annexes

Annex 1: Contact information on participants in the project activity

Annex 2: Information regarding public funding

Annex 3: Baseline information

Annex 4: Monitoring plan

Annex 5: Information on public stakeholder consultation

SECTION A. General description of project activity

A.1. Title of the project activity:

Pakarab Fertiliser Co-generation Power Project
Version 3
13 July 2012

A.2. Description of the project activity:

Pakarab Fertilizer Limited (PFL) is a major fertilizer complex producing both Nitrogenous and Phosphatic fertilizers. The complex is not connected to the national electricity grid. Power and steam for the fertilizer processes as well as for common consumers within the Pakarab Fertilizer area are currently supplied by the captive power plant on-site, without any cogeneration.

The existing steam power plant is from the technical point of view in a good operational condition. However, its efficiency is low due to the applied technology. Power is generated by condensing steam turbines with low steam parameters and process steam for the factory in a heat-only process resulting in a high fuel consumption and high CO_2 emissions.

Some moderate increase of the power demand and a stronger increase of the steam demand of the fertiliser complex are expected for the medium term. The first, low investment option (baseline scenario) to meet the additional demand is the installation of an additional new steam boiler. In this case, however, there will be no improvement with regard to energy efficiency and CO_2 emissions.

Therefore PFL are considering as CDM project activity to replace the existing captive condensing power plant with a new highly energy efficient co-generation plant. Primarily the new plant shall completely cover the power and steam demand of the fertiliser complex and the existing power house will be further used as backup and for standby purposes.

In the absence of the project activity the baseline scenario comprises the generation of electricity by condensing steam turbines, and the generation of steam in heat-only mode by the existing plant. In order to meet the additional future demand the installation of an additional new steam boiler will be necessary.

The project activity comprises the co-generation of electricity and heat (steam): the waste heat of the gas turbines is used by heat recovery steam generators (HRSGs) to produce the steam that would have produced in heat-only mode in the baseline scenario. Fossil fuel is saved and accordingly GHG emissions are reduced by avoiding the release of the condensing heat to the atmosphere in the baseline scenario.

The proposed project activity also contributes to sustainable development by

- reduction of local air pollutant emissions
- transfer of modern gas turbine cogeneration technology
- creation of employment during construction and operation
- further additional measures by Pakarab (outside of the direct project boundaries)
    - filtration plant in chemical complex
    - development of children park
    - construction of community school

(please refer to section D.1.)

A.3. Project participants:

Name of Party involved (*) ((host) indicates a host Party)	**Private and/or public entity(ies) project participants (*) (as applicable)**	**Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)**
Pakistan	Pakarab Fertiliser Limited	No
Germany	Fichtner GmbH & Co. KG (Consultant)	No
(*) In accordance with the CDM modalities and procedures, at the time of making the CDM-PDD public at stage of validation, a Party involved may or may not have provided its approval. At the time of requesting registration, the approval by the Party(ies) involved is required.		

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

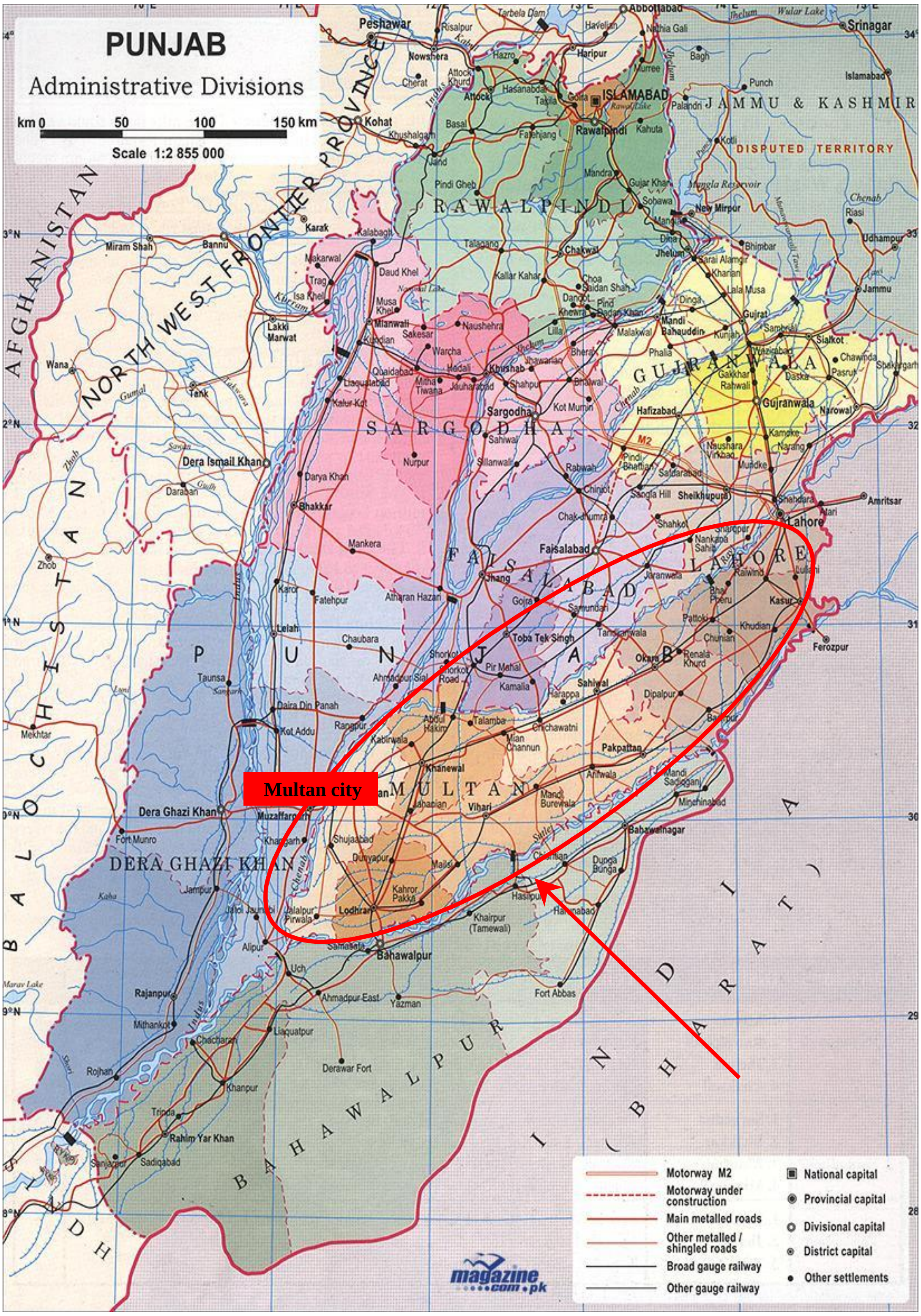
A.4.1.1. Host Party(ies):

Islamic Republic of Pakistan

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

Province Punjab
Punjab is Pakistan's second largest province at 205,344 km.

Figure 1: Punjab province



A.4.1.3. City/Town/Community etc:

Multan; Multan is a city in the Punjab Province of Pakistan and the capital of Multan District. It is located in the southern part of the province. Relevant meteorological data for Multan for the years 1991 to 2005 have been summarised and are shown below:

- Mean annual air temperature 25.4 °C
- Extreme maximum air temperature 50 °C
- Extreme minimum air temperature 0 °C
- Mean relative humidity 57 %

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

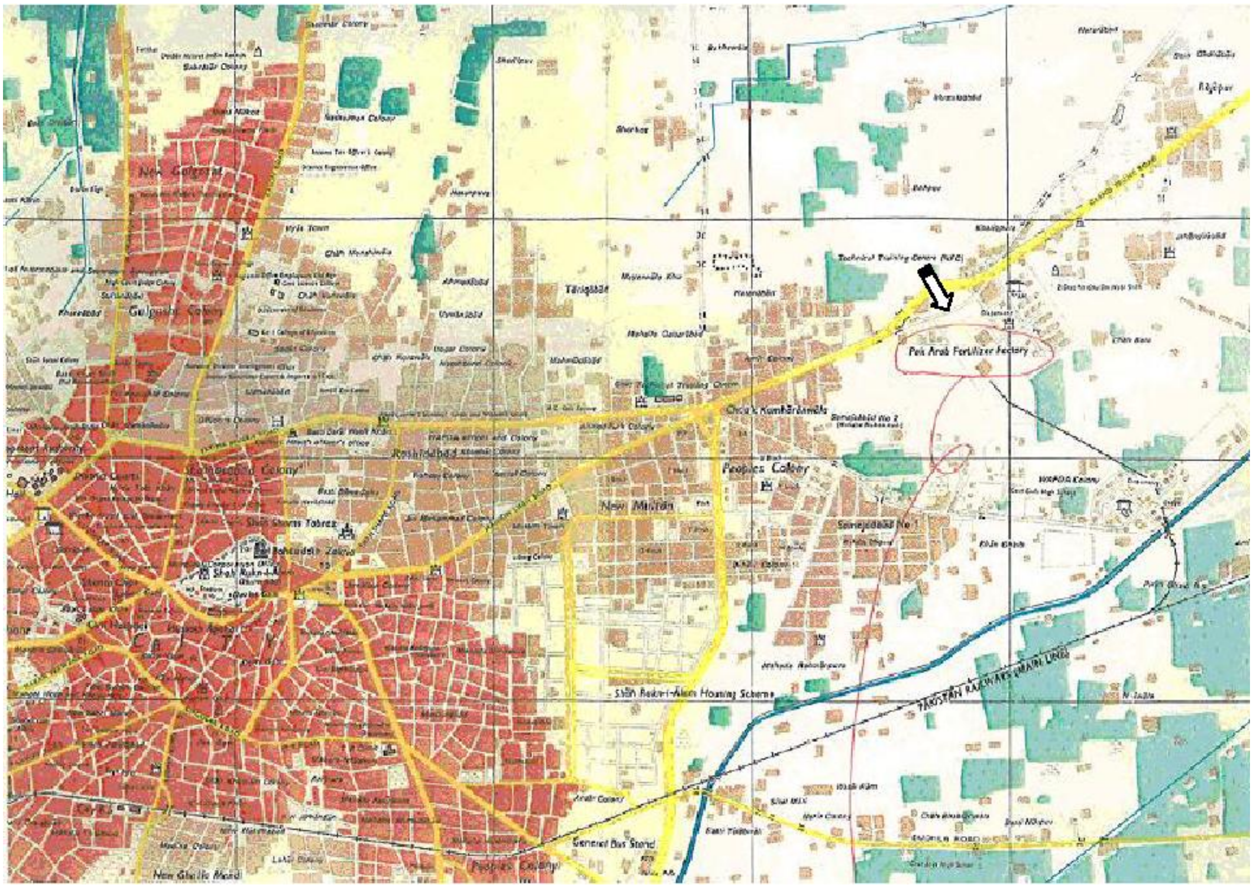
Pakarab Fertilizer factory is situated about 10 km north-east to the centre of Multan city, Pakistan, on the highway leading to Lahore.

The geographical coordinates of the project activity are as follows:

Latitude: 30°12′00″N

Longitude: 71°27′00″E

Figure 2: Location of Pakarab Fertilizer factory in Multan City



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

The project activity falls under:

- Sectoral scope 1: Energy industries (renewable - / non-renewable sources);
- Sectoral scope 4: Manufacturing industries.

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

Current and expected energy demand of the Fertiliser Complex

Due to extensions on the production side of the fertiliser complex some moderate increase of the power demand and a stronger increase of the steam demand is expected. In Table 1, the current and the in future expected demands are shown. The demand increase is due to an increased output of the fertilizer complex.

Table 1: Net energy demand and consumption of the fertiliser complex

	Current demand		**Expected demand**	
	Power	**Steam**	**Power**	**Steam**
Maximum	23 MW	150 t/h	25 MW	170 t/h
Annual average	18.1 MW	100 t/h	22.2 MW	150 t/h
Equivalent operating hours *)	8,280 h/yr	8,280 h/yr	8,280 h/yr	8,280 h/yr
Annual production	149.9 GWh/yr **)	828 kt/yr**) 3,424 TJ/yr	183.8 GWh/yr	1,242 kt/yr 3,635 TJ/yr

*) referred to the annual average output and average net production of steam and power
**) Average production 2004 - 2006 according to plant operator

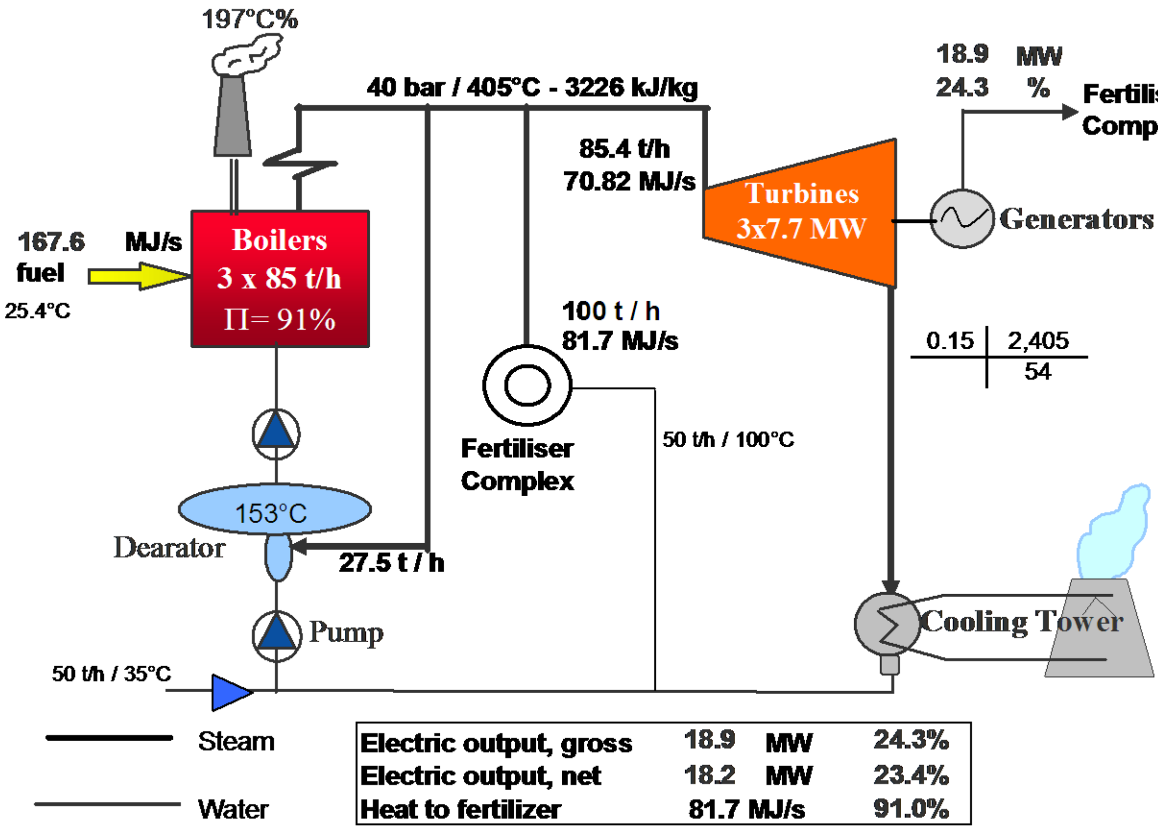
Description of the scenario existing prior to the start of the implementation of the project activity

Steam is produced for following basic purposes;

1. Operation of three turbo-generators (7.7 MW each) to produce electricity for internal use.
2. Heating of process streams to produce fertilizers.
3. To drive the auxiliary drivers (steam turbines) of different pumps / compressors.

A simplified heat flow diagram of the existing power plant including the main process parameters is shown in the heat flow diagram in Figure 3 below. A detailed heat flow diagram including cycle calculation with Fichtner's thermodynamic cycle simulation software KPRO® is shown in Annex 3e.

Figure 3: Simplified heat flow diagram of the existing power plant, annual average operation



The existing power house has **three conventional natural gas fired water-tube steam boilers** that were commissioned in 1978. Each boiler has the capacity of 85 ton/hr at 40 bar pressure and 405 °C temperature. Their technical condition corresponds to the state-of-the-art of the time of their commissioning and is satisfactory taking into consideration their age. During the annual maintenance of the production facilities, which in average takes about 3 weeks, there is still some low demand of electricity and steam. The boilers' capacity is, however, too large for this demand. To keep them operative at minimum load during this time, steam is vented. Hence the average annual efficiency drops.

The boiler efficiency is assessed in a combustion calculation including a complete heat balance as shown in Annex 3d. Relevant parameters for the calculations as flue gas temperatures and O_2-content of the flue gases are taken from the boiler lok book for 5 typical days as shown in Annex 3f. The plant's efficiency is influenced by the following factors:

- The boiler exhaust temperature is with 197 °C (average for 3 boilers of 5 typical days in 2007 and 2008- see Annex 3f) very high, and therefore a lot of heat goes to the atmosphere with the flue gases. The reason may be deteriorated heat exchange surfaces due to the age of the boilers.
- The boilers are operated with about 10.3% excess air. This has been calculated from the records for O_2 content of the flue gases for the 5 typical days

Based on this parameters and the composition of the natural gas, a combustion efficiency of 91 % has been calculated (flue gas losses only). Taking into consideration radiation losses of about 0.5 percentage points and also part load losses the annual average efficiency will be lower than 90%.

The **3 steam turbines** are of pure condensing mode without any steam extraction. They were also commissioned in 1978.

- The exhaust steam at the outlets of the turbines still contains energy which however cannot be recovered because of its low pressure. Hence this energy is lost to the cooling water.
- The condensing pressure of 0.15 to 0.20 bara is for the purpose of power generation relatively high which has some negative impact on the electric efficiency of the plant. The average condensing temperature of 56°C is taken from records delivered by Pak Arab for 24 typical days in 2007, see Annex 3g. This condensing temperature implies an average condensing pressure of 0.165 bara. For conservativeness, a condensing pressure of 0.15 bara resulting in a comparatively high electric efficiency for the baseline situation is chosen.
- During annual overhaul of the factory (about 3 weeks), a minimum steam and electricity generation is required but due to higher capacity of the boilers steam has to be vented which represents a loss to the company.

In the power plant also a black start engine generator unit with 2 MW is available.

The Process steam for the fertiliser complex as well as steam for the de-aerator is taken directly from the live steam header. On average about 50 percent of the condensate is returning from the fertiliser complex to the power stations with a temperature of 100 °C. The in-house (own) power demand of the power station has been estimated to be about 0.7 MW. The main results of the thermodynamic cycle calculation based on measured steam cycle parameters and adjusted for conservativeness are shown in Table 2 (see also detailed thermodynamic cycle simulation in Annex 3e).

Table 2: Thermodynamic process parameters of existing captive power plant

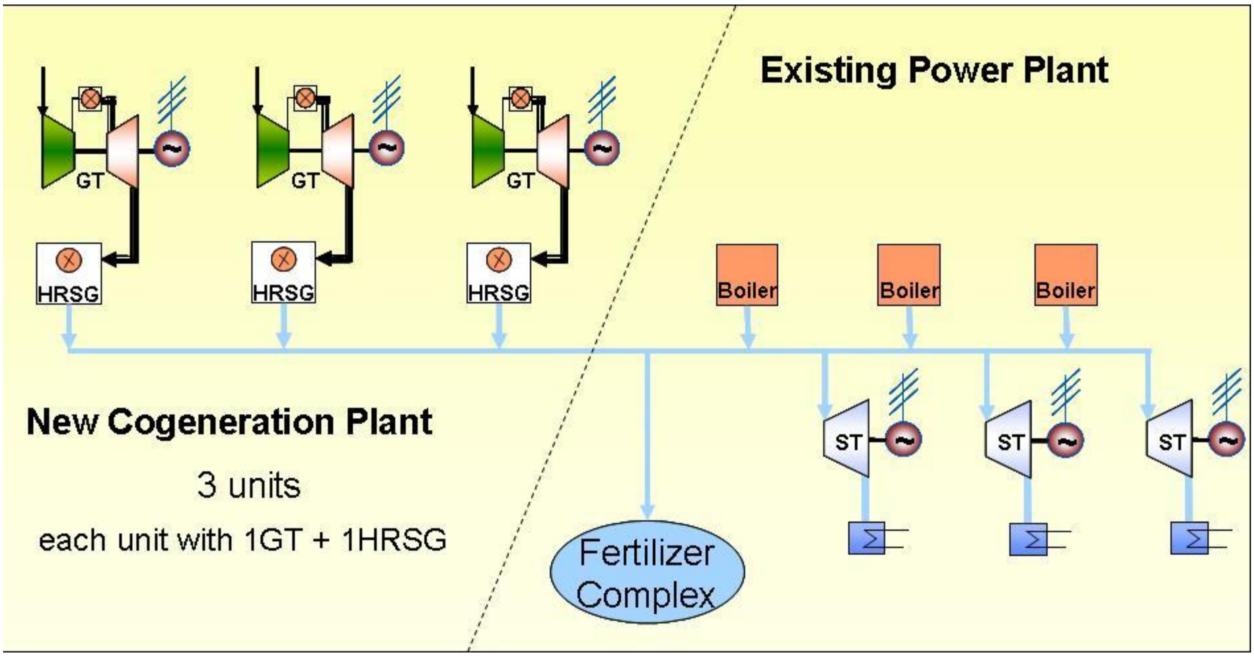
	Output	**Heat Consumption MJ/s**	**Fuel Consumption MJ/s $_{NCV}$**	**Overall Efficiency %**	**Fuel rate *) NCV**	
Process steam **)	100 t / h	81.70	89.78	91.0	3.23 GJ_{NCV}/t_{steam}	1.10 GJ_{NCV}/GJ_{th}
Electricity, net ***)	18.2 MW	70.82	77.82	23.4	15.38 GJ_{NCV}/MWh_{elec}	

*) Fuel energy divided by final energy produced; NCV = net calorific value (lower heating value, LHV)
**) Live steam 40 bar/405°C, average condensate return 50 % at 100°C
***) Gross output 18.9 MW, in house demand power stations 0.7 MW

The efficiency of the plant is due to the lack of cogeneration and the low live steam parameters - 40 bar / 405 °C - and relatively high condensing pressure (0.15 bara) quite poor, and fuel consumption as well as all emissions including CO_2 quite high.

Description of the activities/measures being implemented within the project activity
As CDM project activity a highly energy efficient **cogeneration plant** is implemented. The new power plant shall almost completely cover the power and process steam demand of the fertiliser complex and the existing power plant will be used as backup and standby unit in case of forced or planned outages of units of the cogeneration plant (see Figure 4).

Figure 4: Overview of new cogen plant and existing power plant



For cogeneration of power and steam with the required parameter of 40 bar/405 °C, a **new gas-turbine cogeneration plant** with three gas turbines and three upstream heat recovery steam generators (HRSG) is implemented as project activity. Several units are chosen for redundancy purposes. The power output and efficiency of gas turbines depend on the site conditions with regard to elevation and ambient temperature. From several gas turbine types which are offered in the market, the one according to Table 3 has been selected for implementation for the project activity.

Table 3: Output of selected gas turbine type GE10-1 for cogeneration plant

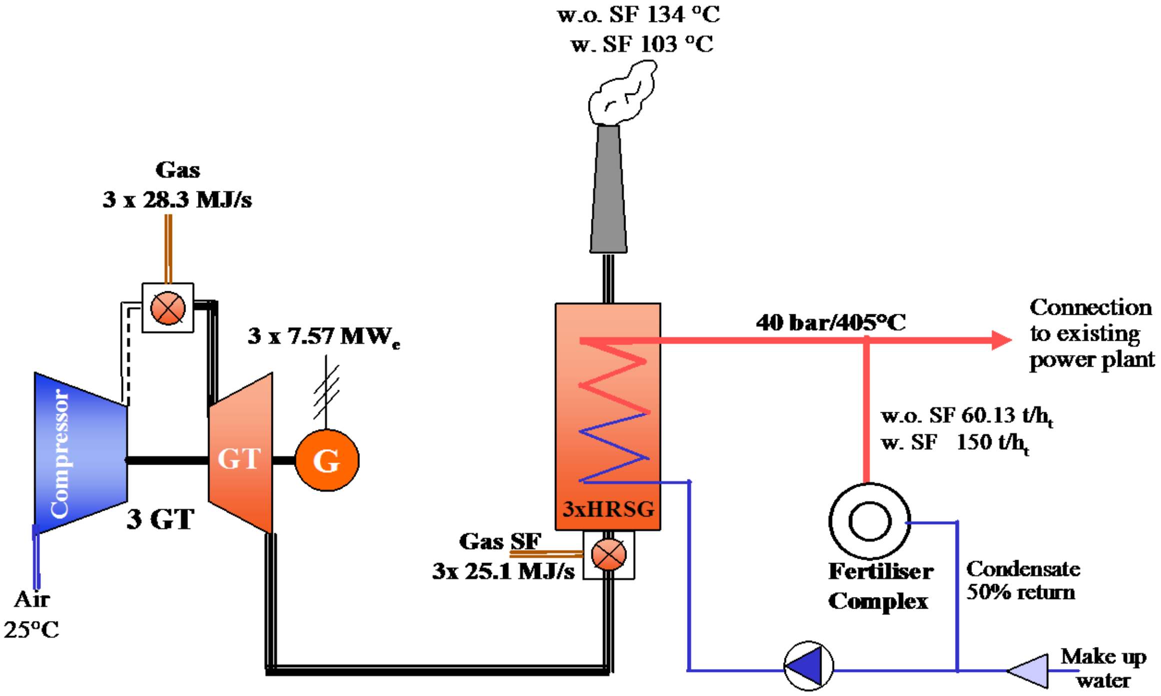
Ambient conditions and load	Output (gross) [MW]	Efficiency ***) [%]
ISO- rating *) and 100% load	10.70	30.36
Average site conditions **) and 100% load	9.70	29.25
Average site conditions **) and annual average load of 78%	7.57	26.70

*) atmospheric pressure 1.013 bar, temperature 15 °C, relative humidity 60 %
**) according to data sheet GT manufacturer for reference site conditions (Annex 3a)
***) gross electric output to firing duty as net calorific value (NCV)

The data are taken from the manufacturer's data sheets, see Annex 3a. At the annual average temperature of 25 °C the selected gas turbines can meet also the expected maximum power demand of 25 MW (3 x 9.7 MW = 29.1 MW). As the average power demand of the fertiliser complex is about 22 MW the gas turbines will have to be operated at part load during most of the time; the consequence will be a lower efficiency.

A simplified heat flow diagram of the cogeneration plant for operation at annual average conditions (25°C) and net power output (22.2 MW) is shown in Figure 5. The in-house (own) power demand of 0.5 MW is derived from similar plants. In pure cogeneration mode, the plant can generate 55.8 t/h process steam. In order to meet the average demand of 150 t/h, the HRSGs are equipped with supplementary firing (SF). At average annual load conditions the electric efficiency declines due to the part load operation as it is typical for gas turbines. Detailed heat flow diagrams with thermodynamic cycle calculations including all relevant thermodynamic parameters of the cycle are shown in Annex 3b (without supplementary firing) and in Annex 3c (with supplementary firing). The overall efficiency, however, with supplementary firing obtains according to the cycle simulations a remarkable level of 92.2 %. The manufacturer of the plant guarantees 91.5% overall efficiency; this may contain some security margin to avoid penalties.

Figure 5: Simplified heat flow diagram of the cogeneration plant at annual average load conditions



Electric output	22.7 MW_e gross, 22.2 MW_e net
Fuel consumption	GT 84.9 MJ/s ; SF 75.3 MJ/s
steam output	w.o. SF 60.13 t/h; with SF 150 t/h
electric efficiency	26.7 % gross, 26.1 % net
overall efficiency, cogen	w.o. SF 85.7 % ; w. SF 92.2 %

SF:supplementary firing

Note: The calculation of the emission reductions is based on 91.5% overall efficiency that is guaranteed by the manufacturer of the plant.

The manufacturers of the major equipment are as follows:
1. HRSGs: UMAG Technologie GmbH
2. Gas turbines: GE Oil & Gas Nuovo Pignone
3. Generators: Ansaldo Italy

The *ex-ante* calculation of Project emissions and Emission reductions in section B.6.3 is based on the manufacturer's guarantee value of 91.5% overall efficiency as a conservative approach. In any case Project emissions will be determined *ex-post* through monitoring of fuel consumption.

The sizing of the electric capacity of the cogeneration plant is based on the electricity demand of the fertiliser complex. As power and process steam demand is co-incident, the plant could be sized for pure cogeneration (without supplementary firing of the HRSG) based on the steam demand of 150 t/h. The electric capacity would be then 3 times higher. In this case, however, the excess power should be exported to the public grid. As there is no grid connection this alternative cannot be realised.

This new technology will save fossil fuel energy and thus reduce GHG emissions:

- By co-generation of electric energy and steam (heat energy).
- With the efficient design of HRSG the flue gas temperature will be reduced and a higher amount of energy of the exhaust gases will be utilized to co-generate steam.
- The efficiency of the gas turbines (GT) is higher than that of the existing captive condensing steam turbine power plant even without co-generation.
- The cooling water is used in the existing captive power plant for condensation of exhaust steam; in case of the new GT cogeneration plant, this will not be required; thus energy for processing of this water will be saved.

Fuels and other media
Natural gas is available at the project site and will be used to operate the gas turbines and HRSG. This is in line with AM0014.

Two existing buried gas pipelines will be relocated. All further media like fuel, cooling water, demineralised water, instrum ent and compressed air, are supplied from the existing facilities.

The electrical consumers are supplied by means of a common 6 kV switchyard fed by the existing as well as the new power plant.

For natural gas, the IPCC 2006 value of 56.1 t CO_2/TJ is chosen for compliance with AM0014, see section B.6.2 below.

Description of the baseline scenario
The power and steam generation capacity of power plant options must be sufficient to cover the complete power and steam demand throughout the year as there is no connection to the public grid. As a first option the further use of the existing power plant comes into consideration. In order to meet the future steam demand, however, the installation of an additional boiler is required. As baseline scenario the existing power plant (see Figure 4) will continue to supply electricity and heat to the fertiliser complex. In order to meet the future demand, however, an additional boiler of the same size as the existing must be installed.

Notably the *baseline scenario* is defined as follows:

- Use of the existing power plant with 3 boilers and 3 steam turbines;
- Installation of an additional 4th boiler with the same capacity and steam parameters;
- Replacement of the existing 3 boilers and turbines around the year 2020;
- Higher than number-plate efficiencies as conservative assumption (baseline scenario 3 above).

The for the baseline emissions relevant thermodynamic parameters of the existing power plant have been calculated with Fichtner's thermodynamic process simulation software KPRO® and are projected for the baseline scenario with future conditions with regard to electricity and heat demand of the fertiliser complex as shown in Table 4.

Table 4: Thermodynamic parameters of the baseline scenario

	Output	**Heat Consumption MJ/s**	**Fuel Consumption MJ/s_ NCV**	**Efficiency %**	**Fuel rate *) NCV**	
Process steam *)	150 t / h	122.6	134.7	91.0	3.23 GJ/t	1.10 GJ/GJ
Electricity, net **)	22.2 MW	86.4	94.9	23.4	15.38 GJ/MWh	

*) Efficiency and fuel rates based on NCV of the fuel
**) In-house electricity consumption 0.7 MW assumed from similar plants acc. Fichtner's experience

In the description of the scenario existing prior to the start of the implementation of the project activity above it was mentioned, that the current thermal efficiency of heat generation will be will be lower than 90%. Nevertheless, as conservative approach according to the selected baseline scenario (see B.4. below, scenario 3), a thermal efficiency of 91 % as annual average for heat production is chosen. This approach will result in lower baseline emissions, and accordingly in lower emission reductions, and is therefore conservative.

A.4.4. Estimated amount of emission reductions over the chosen crediting period:

Utilising the methodology described in section B2, the project activity will result in a fuel reduction of 2,168 TJ per year and an emission reduction of 119,481 tCO_{2e} per year. Expected start of operation of the cogeneration plant is third quarter of 2009.

Table 5: Estimated amount of emission reductions

Years	Annual estimation of reductions in tonnes of CO_2e
Year 1 (September – December 2009)	39,827
Year 2 (2010)	119,481
Year 3 (2011)	119,481
Year 4 (2012)	119,481
Year 5 (2013)	119,481
Year 6 (2014)	119,481
Year 7 (2015)	119,481
Year 8 (January – August 2016)	79,654
Total estimated reductions (1st Crediting period of 7 years)	836,367
Annual average over the crediting period of estimated reductions	119,481
Total estimated reductions (Total maximum crediting period of 21 years)	2,580,165
Total number of crediting years	3 x 7 years = 21 years

A.4.5. Public funding of the project activity:

There is no public funding of the project activity.

SECTION B. Application of a baseline and monitoring methodology

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

AM0014/Version 04 (EB33 decision)
"Natural gas-based package cogeneration".

No other methodologies or methodological tools where the methodology refers to were used.

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

All of the applicability criteria of methodology AM0014 are fulfilled by the project activity:

- The electricity and heat requirement of the consuming facility is generated in separate systems in the absence of the project activity. As can be seen in Figure 4 above, the current system for electricity generation comprises the boilers and the condensing steam turbines. The current system for heat generation comprises the steam boilers only. There is no technical possibility to extract process steam from the steam turbines. Therefore, the baseline situation is separate generation of electricity and heat requirements;
- The cogeneration system is owned by the industrial user that consumes the project heat and electricity;

- The cogeneration system provides all of the electricity and or heat demand of the consuming facility;
- No excess electricity is supplied to the power grid and no excess heat from the cogeneration system is provided to another user;
- As the project activity displaces electricity from a fossil fuel based dedicated power plant, emission reductions from only the fraction of displaced electricity from the baseline dedicated power plant are claimed.

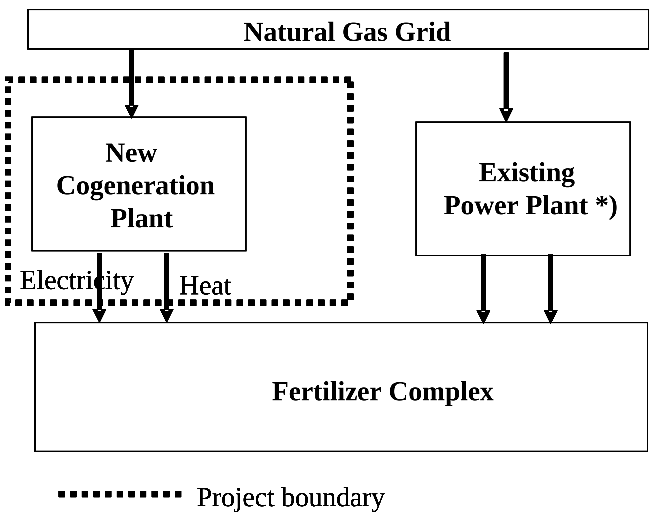
PFL currently does not have a power grid connection. The baseline for **CO_2 from electricity generation** is thus a dedicated fossil fuel power plant, namely the existing steam turbine captive condensing power plant with efficiency higher than the number-plate efficiency, see Section B.4.

B.3. Description of the sources and gases included in the project boundary

The new cogeneration plant will supply electricity and heat in form of steam to the fertiliser complex. The main fuel is natural gas, which is delivered by the national grid. The existing power plant serves as back-up and for stand-by purposes and in case of operation would consume natural gas.

The project boundary for the calculation of project emissions comprises the cogeneration plant only, see Figure 6. Baseline emissions are those emissions which would be associated with the production of heat and electricity in the absence of the project activity, and which are offset by the output of the cogeneration plant.

Figure 6: Project boundary



*) Separate generation of electricity and heat by existing plant, see also Figure 3 and Figure 4

Table 6 describes the GHG emissions included or excluded in the project boundary.

Table 6: General overview of sources and gases included in the project boundary

	Source	Gas	Included	Justification / Explanation
Baseline	Steam boilers of existing Power Plant	CO_2	Yes	CO_2 emissions corresponding to combustion of natural gas for generation of *electricity and* heat in form of process steam
		CH_4	No	See project activity
		NO_2	No	See project activity
Project activity	Gas turbines and HRSGs of the new Cogeneration Plant	CO_2	Yes	CO_2 emissions corresponding to the combustion of natural gas in the gas turbines and in the Heat Recovery Steam Generator
		CH_4	No	Negligible respectively lower than the default emissions of the existing system
		NO_2	No	Negligible respectively lower than the default emissions of the existing system

AM0014 provides also for project and baseline emissions to be calculated for:
b) CH_4 from combustion
c) N_2O from combustion
d) CH_4 leaks during production/supply of the fuel

The project situation compared with the baseline situation will result in an overall reduction in natural gas consumption. As a result of lower natural gas consumption and despite the consideration of respective CH4/N2O emission factors for the baseline and project technology, overall methane and nitrous oxide emissions expressed as CO2 equivalent emissions will be reduced in the project situation compared to the baseline. However, for simplification these emission reductions are not further considered. The calculated total emission reductions are therefore conservative. For the purpose of transparency, the neglected amount of CO2e emissions has been calculated as per the below procedure.

Pakarab has not available plant specific data for total quantity of methane and nitrous oxide emissions expressed in tCH_4/a and tN_2O/a or emission factors expressed in $kgCH_4/TJ$ and kgN_2O/TJ. The Pakistan Energy Yearbook 2008 has been referred but this source of information does not provide any national energy statistics on methane and nitrous oxide emission factors for specific combustion technologies.

Therefore, IPCC 2006 Guidelines for National Greenhouse Gas Inventories, Vol. 2 Energy, Chapter 2.3.3 are referred for quantifying the additional emission reductions from methane and nitrous oxide, which is an acceptable approach according to Methodology AM0014 Version 04.

From the analysis of the choice of activity data it is concluded that the PP should refer to default values for methane and nitrous oxide emission factors as provided by IPCC in absence of any country or plant specific data. Table 7 (Table 2.7 of quoted IPCC guidelines "Industrial source emission factors") summarizes the default values used.

Table 7: IPCC default emission factors

Table 2.7 "Industrial source emission factors"		
Basic technology Natural Gas	**CH_4 [kg/TJ energy input)**	**N_2O [kg/TJ energy input]**
Boilers	1	1
Gas-Fired gas Turbines >3MW	4	1

Annex 3h to the PDD "Ex-ante calculation of baseline and project emissions" provides fuel consumption data. The key values are summarized in Table 8.

Table 8: Fuel consumption (natural gas) in the baseline and project

Fuel consumption	Unit	Baseline	Project activity	Fuel reduction
Total	TJ_{NCV}/yr	6,826	4,696	2,130
- of which boilers	TJ_{NCV}/yr	6,826	1,868	
- of which gas turbines	TJ_{NCV}/yr		2,828	

With above activity data and Global Warming Potential for methane = 21 and nitrous oxide = 310 a CO2e emission reduction from both gases is calculated as **527 tCO2,eq/yr**. This amount of emission reductions will not be claimed, which confirms again that the overall calculation of emission reductions as stated in the PDD is conservative. A detailed calculation has been provided to the DOE.

B.4. Description of how the baseline scenario is identified and description of the identified baseline scenario:

Identification of baseline scenario
Likely alternative baseline scenarios according to AM0014 are:

1. Industrial plant continues to operate with equipment replacement as needed with no change in equipment efficiency (The frozen-efficiency scenario).
2. Industrial plant continues to operate with improved efficiency new equipment at the time of equipment replacement using a less carbon intensive fuel.
3. Industrial plant upgrades the thermal energy generating equipment and therefore increases the efficiency of boiler(s) immediately.
4. The heat and or electricity demand of the industrial plant is reduced through improvements in end-use efficiency.
5. Installation of a cogeneration system owned by the industrial plant (The proposed project activity) without CDM.
6. Installation of a package cogeneration system owned by a company other than the industrial.
7. Installation of a cogeneration system by a third party.

It is likely that in the short- and medium-term the current plant will continue to be operated with the existing equipment and equipment be replaced only when it will achieve the end of its technical lifetime (baseline scenario 1). However, as conservative approach, it is assumed that the efficiency of the existing facilities for power and heat generation achieves number-plate ratings (baseline scenario 3). A specific reduction of heat and electricity demand is already considered for the design of the extension of the fertilizer complex. Nevertheless, power demand will increase slightly, and heat demand significantly, as indicated above in section A.4.3. Baseline scenario 4 is therefore already implicitly considered in the future demand values of the fertilizer complex. Baseline scenarios 5 to 7 all include cogeneration technology that faces the technological and institutional barriers as indicated in section B.5. They are therefore not the baseline.

Description of baseline scenario

Section A.4.3. comprises an extensive description of the baseline scenario. As baseline scenario the existing power plant (see Figure 3) will continue to supply electricity and heat to the fertiliser complex. In order to meet the future demand, however, an additional boiler of the same size as the existing must be installed.

Notably the *baseline scenario* is defined as follows:

- Use of the existing power plant with 3 boilers and 3 steam turbines;
- Installation of an additional 4th boiler with the same capacity and steam parameters;
- Replacement of the existing 3 boilers and turbines around the year 2020 [1];
- Higher than number-plate efficiencies as conservative assumption (baseline scenario 3 above).

As discussed previously in Section B.3, CH_4 and N_2O emissions are, for conservative reasons, not considered:

b) The baseline methane emissions from combustion of baseline fuel for heat supply are neglected.
c) The baseline nitrous oxide emissions from combustion of baseline fuel for heat supply are neglected.
d) The baseline methane emissions from natural gas production and pipeline leaks in the transport and distribution are neglected.
e) Baseline emissions of CO_2 from electricity supply to industrial plant, that are offset by electricity supplied from cogeneration system

Because PFL is not connected to the power grid, the baseline is the dedicated fossil fuel power plant.

B.5. 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 (assessment and demonstration of additionality):

Pakarab Fertilizers Ltd. implemented in the year 2005/06 the CDM project Catalytic N_2O Abatement Project in the Tail Gas of the Nitric Acid Plant (CDM project number 0557). It was registered on November 05, 2006 as CDM project. Therefore, Pakarab is already aware of the CDM and its benefits since the initial stages of the project development of the current cogen project. The timeline of the project development and implementation for the cogeneration project has been as follows:

	Timeline	Project implementation step/stage
a)	08/2005 – 02/2006:	Information gathering on technologies by Pakarab (e.g. initial Feasibility Study on 30 MW Co-Generation Plant dated December 12, 2005)
b)	03/2006 – 09/2006:	Conceptual study by Fichtner
c)	05/2006:	Proposal on CDM services by Fichtner
d)	10/2006 – 12/2006:	Preparation of tendering documents by Fichtner
e)	01/2007 – 06/2007:	Tendering of major equipment
f)	March 21, 2007:	Contract signature on CDM services
g)	Since 03/2007:	Development of CDM documentation
h)	June 7, 2007:	Local Stakeholder Consultation Meeting (see Annex 5)
i)	July 13, 2007:	Order of gas turbines (1st equipment purchasing contract = starting date of the CDM project activity)
j)	August 6, 2007	2nd Purchase Order for 3 GTG, placed after 1st Order was canceled

[1] A certificate from DESCON Engineering Limited has been provided to the DOE, which confirms that the equipment can be kept operational until the year 2020. This certificate also confirms that boilers and turbines were installed and commissioned in 1978 and have been maintained since.

k)	January 28, 2008:	Letter of host-country by Government of Pakistan
l)	Since 01/2008:	Construction
m)	April 17, 2009:	GTG No.1 commissioned
n)	April 29, 2009:	GTG No. 1 has been started and is connected on distribution network through busbar
o)	Currently (May, 2009)	Second GTG precommissioning activities underway
p)	June - July (expected)	GTG No. 2 and No. 3 will start operation.

Evidence to document this implementation timeline has been made available to the validating DOE. Based on the definition within the Glossary of CDM terms (version 4), the starting date of the CDM project activity is July 13, 2007, when Pakarab made the first equipment order for the project implementation. Prior to this equipment order, Pakarab had already signed the CDM services contract on March 21, 2007. On June 7, 2007, the Local Stakeholder Consultation was also carried out before the starting date of the CDM project activity. The Minutes of Meeting of the Local Stakeholder Consultation (see Annex 5b) provide evidence that the incentive provided by the CDM was seriously considered in the decision to proceed with the project activity. The benefits of the CDM in form of tradable CERs were a decisive factor for Pakarab to proceed with the project and sign the gas turbine order 5 weeks after the local stakeholder consultation meeting has taken place. Regarding EB 41, Annex 46, §5a) guidance, further evidence is provided to the DOE in form of communication between the CEO and Technical Manager. The timeline above also demonstrates continuous efforts in gathering the status as registered CDM project activity.

According to AM0014, Version 4 the project developer can demonstrate additionality by selecting one of the following two options:

- Option 1: apply Step 2 of the latest version of the “Tool for demonstration of additionality” (Investment Analysis).
- Option 2: Methodology-specific process for determination of additionality as follows:

Four additionality tests are applied. The first two tests are applicable to any cogeneration ownership scenario. The third test is specific to the “package cogeneration” case where the cogeneration system is owned by a party other than the industry using the heat and electricity from the system. The fourth test is specific to the “package cogeneration” case for the self-owned cogeneration system. In the case of self owned Cogeneration project activities the project activity is additional if all the four additionality tests result in project being assessed as additional, whereas, only the first three tests need be applied in the case of third party ownership

In the following, additionality is demonstrated according to Option 2 above.

1. Are there technological barriers to cogeneration in the country?

Figure 7 shows the flow chart for the additionality test 1 according to AM0014. Pakistan doesn’t have a study quantifying its economic cogeneration potential.

According to official IEA statistics, Pakistan’s installed cogeneration (combined heat and power, CHP) capacity is 0 (www.iea.org/Textbase/stats/balancetable.asp?COUNTRY_CODE=PK).
According to another source, the WEPP database, Pakistan’s installed cogen capacity in 2004 was 276.53 MW in 22 premises (see also compilation in Annex 3i). The UDI World Electric Power Plants Data Base (WEPP, Copyright © 2007, Platts, a division of The McGraw-Hill Companies, Inc.) is a global inventory of electric power generating units. It contains design data for plants of all sizes and technologies operated by regulated utilities, private power companies, and industrial auto producers. A brief description of the

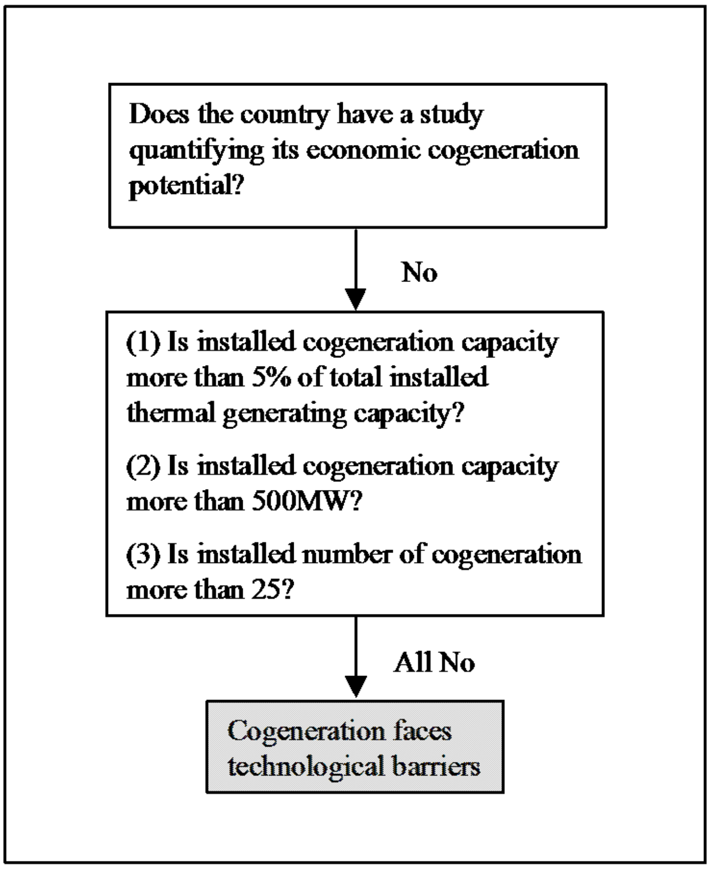
database and its copyright is included as Annex 3j. An insight into the database was made available to the DOE during validation.

Pakistan's total installed capacity in 2004 (source: WAPDA-Power System Statistics Twenty Ninth Issue) was:

- hydropower: 6,493 MW (33.2 %)
- thermal power: 12,567 MW (64.4 %)
- nuclear power: 462 MW (2.4 %)
- total: 19,522 MW (100 %)

The cogen capacity in Pakistan in 2004 of 276.53 MW was therefore 2.2 % of the installed thermal power of 12,567 MW, below the 5 % threshold of AM0014. The installed cogeneration capacity in Pakistan is well below the threshold of 500 MW. This capacity is installed in 23 cogen plants, also below the 25 threshold of AM0014. Cogeneration therefore faces technological barriers in Pakistan.

Figure 7: Flow chart for technological barriers to cogeneration in Pakistan



2. Are there institutional barriers to cogeneration in general?

Figure 8 shows the flow chart for the additionality test 2A according to AM0014. Written evidence in form of a comfirmation provided by tax advisor A.F.Ferguson & Co. is provided to the DOE and EB confirming that in Pakistan no preferential tariffs, financing, or fiscal benefits exist compared to other generators. The test is therefore inconclusive with respect to institutional barrier 2A.

Figure 8: Flow chart for institutional barrier 2A to cogeneration in Pakistan

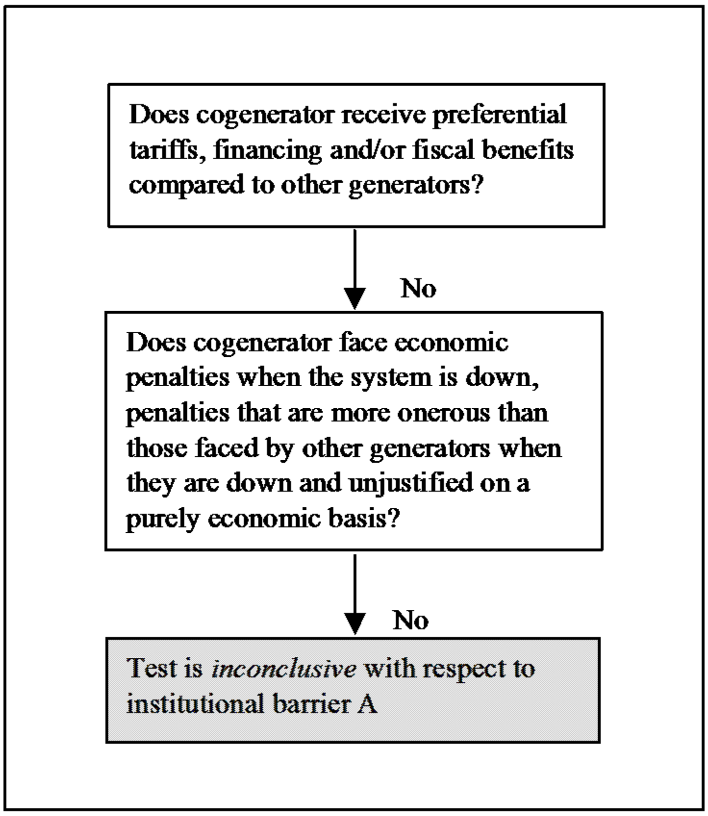


Figure 9 shows the flow chart for the additionality test 2B according to AM0014. Extensive research on the activities of ESCOs in Pakistan has been carried out while preparing this PDD.

In absence of any clear definition of ESCO in AM0014 a commonly and internationally used definition of ESCO (Energy Service Companies) is adapted from the National Association of Energy Service Companies, weblink: http://www.naesco.org/resources/esco.htm

According to NAESCO *"An ESCO, or Energy Service Company, is a business that develops, installs, and arranges financing for projects designed to improve the energy efficiency and maintenance costs for facilities over a seven to twenty year time period. ESCOs generally act as project developers for a wide range of tasks and assume the technical and performance risk associated with the project. Typically, they offer the following services:*

- *develop, design, and arrange financing for energy efficiency projects;*
- *install and maintain the energy efficient equipment involved;*
- *measure, monitor, and verify the project's energy savings; and*
- *assume the risk that the project will save the amount of energy guaranteed.*

These services are bundled into the project's cost and are repaid through the dollar savings generated."

Two references are quoted and used for this analysis, namely:

- "An Assessment of Energy Service Companies (ESCOs) Worldwide" published by the World Energy Council / Central European University; March 2007. This document is provided to the DOE and EB.
- "Accredited Energy Service Companies (ESCOs)" published by Bureau of Energy Efficiency, Ministry of Power, Government of India, November 2008. This document is provided to the DOE and EB.

Reference no 1, "An Assessment of on Energy Service Companies (ESCOs) Worldwide" does not make any reference to Pakistan and therefore is not a useful source. Reference no 2 "Accredited Energy Service Companies (ESCOs)" mentiones that of 17 ESCOs accredited by ICRA Limited (formerly Investment Information and Credit Rating Agency of India Limited) for India, just one is also active in Pakistan. It is company called Seetech Solutions Pvt. Ltd. The grading of the company denotes good ability to carry out energy efficiency audits and implement energy saving project. No mention is given that this company is active also in co-generation power generation planning, implementation, financing etc. Furthermore, the scope of business of this company does not entirely fit the above quoted definition of ESCO as provided by NAESCO. This company only provides a few activities from the possible scope of activities ESCOs typically perform. Therefore, it can be concluded that there are no active ESCOs operating in Pakistan that have co-generation plants operating.

In addition phone consultations with Fichtner and its local experts in Pakistan were held in which it could be confirmed "that the concept of ESCO as typically operating in European countries is non-existent in Pakistan." Reference is provided to the DOE and EB.

It can therefore be concluded that package cogeneration faces institutional barrier 2B in Pakistan, even if this test is not applicable for the current project activity ("The third test is specific to the "package cogeneration" case where the cogeneration system is owned by a party other than the industry using the heat and electricity from the system.").

Figure 9: Flow chart for institutional barrier 2B to cogeneration in Pakistan

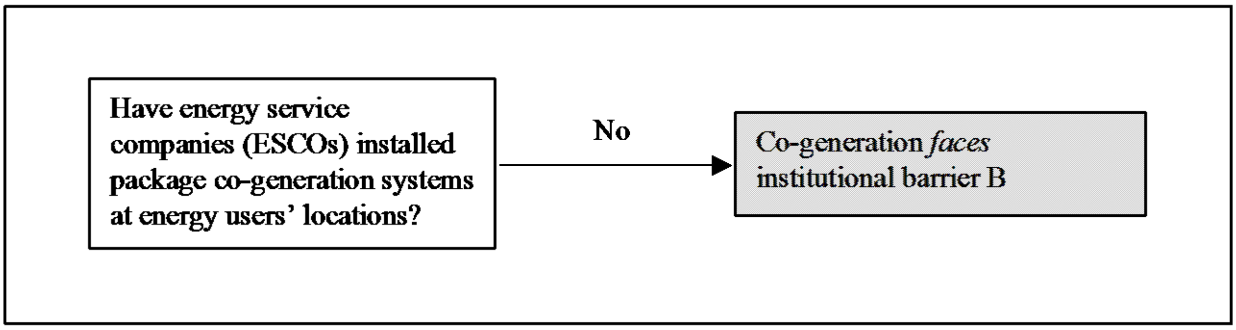
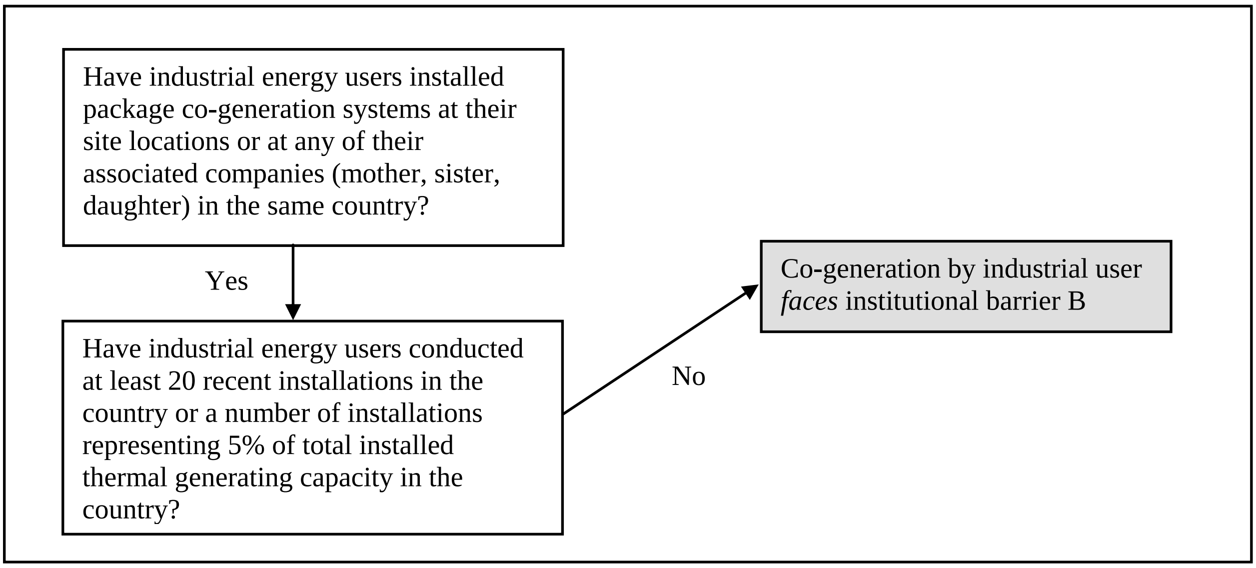


Figure 10 shows the flow chart for the additionality test 2C according to AM0014, which is about investigation of the level of package cogeneration plant diffision in Pakistan.

Figure 10: Flow chart for institutional barrier 2C to cogeneration in Pakistan



The UDI World Electric Power Plants Data Base (WEPP, Copyright © 2007, Platts, a division of the McGraw-Hill Companies Inc.) has been used as reference to analyze this barrier. A cluster of all cogeneration plants was formed,, which include all operating and planned facilities. The total installed capacity was calculated as 343.03 MW of which 276.53MW represent the operating plants. From this cluster (operating plants) the share of market diffusion was calculated.

The database provides a total of 24 plants (with 52 units) and a total co-generation capacity of 282.03 MW. Details are provided in Annex 3i of the PDD.

With this dataset the first condition of the 2C institutional barrier test was then assessed: "Have industrial energy users installed package co-generation systems at their site locations or at any of their associated companies (Mother, sister, daughter) in the same country? The answer to the question is "YES" as there are industrial co-generation users in chemical, sugar, textile and other sectors.

Then the second condition of 2C institutional barrier test was assessed: "Have industrial energy users conducted at least 20 recent installations in the country or a number of installations representing 5% of total installed thermal capacity in the country?"

In absence of a clear definition of "recent" and "installations" in the methodology the PP defined "recent" as the latest 10 years" and "installations" as the "plants". The cluster of cogeneration plants in the period 1998 - 2007 includes therefore 5 plants with an overall installed capacity of 71.85 MW. For specification of the plants including their commissioning year it can be referred to Annex 3i, plant 2 (with units 2a-b), 4, 7 (with units 7a-c), 8 (with units 8a-b), and 19. The first criteria is therefore fulfilled because there have only been 5 recent installations (plants) which is less than 20 installations (plants) as stated in Methodology AM0014.

Table 9: Structure of industrial cogeneration plants in Pakistan (recent installations from 1998 to 2007)

Industrial sector	Number of plants	Number of units	Share
Chemical / Fertilizer	1	2	73%
Fuel sector	1	1	9%
Textile	1	3	4%
Other (Glass / Refinery)	2	3	13%
Total	**5**	**9**	**100%**

Source: own calculation based on The UDI World Electric Power Plants Data Base

Then, the total installed capacity of cogeneration plants was compared with the installed thermal generating capacity in Pakistan. The total thermal generating capacity in Pakistan was also determined from the above mentioned source. In order to determine the sample group only those plants marked with "operating status" have been selected same as for the selection of co-generation plants. In addition, all plants running on renewable fuels (e.g. biomass, bagasse) were eliminated from the generic data base. The total thermal generation capacity for all operating plants is determined at 20,282.12 MW. The 282.03 MW operating co-generation thus represents only 1.39 % of total thermal generation. This result is far below the 5% benchmark set in the institutional barrier 2C test.

Table 10:Share of total co-generation of total thermal generation

Item	Installed capacity	Share of total generation	share of operating thermal generation
	MW	%	%
Total operating generation	20656.86	100%	
Total operating thermal generation only	20282.12	98.19%	100%
Total co-generation	282.03	1.37%	1.39%

Source: own calculation based on The UDI World Electric Power Plants Data Base

Both conditions can therefore be answered with "NO". It can therefore be concluded that the project faces institutional barriers as per 2C test.

As conclusion, cogeneration faces technological and institutional barriers in Pakistan. Therefore, scenarios 1 to 4 according AM0014 and as listed under Section B.4 remain as baseline scenarios.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

Calculation of project emissions

The project emissions will be determined *ex-post* based on the gas consumption as measured and monitored. Project emissions correspond to the consumption of natural gas by the cogeneration system. CO_2 emissions from combustion in the gas turbines and in the supplementary firing of the heat recovery steam generator are relevant.

a) CO_2 emissions from natural gas combustion in cogeneration system

Carbon dioxide emissions from natural gas combustion in the cogeneration system, PE_{CS} (tonne CO_2/year):

$$PE_{CS}{*} = AEC_{NG} \times EF_{NG} \quad (tCO_2 / yr) \qquad \textbf{(4.1)}$$

Where as: AEC_{NG} = annual natural gas consumption in TJ/yr
EF_{NG} = CO_2 emission factor of natural gas in t CO_2 / TJ

*: PE is used instead of E as acronym for Project Emissions as indicated in the methodology.

The annual natural gas consumption AEC_{NG} of the new cogen plant will be determined as follows:

$$AEC_{NG} = V_{NG} \times NCV_{NG} \times 10^9 (TJ / yr) \qquad \textbf{(4.1a)}$$

Where: V_{NG} = annual natural gas consumption in Nm³/yr
NCV_{NG} = Net Calorific Value of natural gas in kJ/Nm³

As discussed previously in Section B.3, CH_4 and N_2O emissions are, for conservative reasons, not considered:
b) Methane emissions from natural gas combustion in cogeneration system are neglected.
c) Nitrous oxide emissions from natural gas combustion in cogeneration system are neglected.
d) Methane emissions from natural gas production and pipeline leaks in the transport and distribution of natural gas, including leakage within the industrial plant are neglected.

All these emissions will be smaller in the case of the project activity rather than the baseline situation, because the national gas consumption will be reduced.

Project emissions of CH_4 and N_2O as well as emissions from leaks by the production and distribution of the natural gas are lower than those of the baseline scenario due to the reduction in fuel consumption. Their consideration would result in a slightly higher reduction of emissions. As conservative approach they are not considered for the calculation of emissions reductions.

Total project emissions are given by the sum of the components analyzed above:

$$PE_{total} = PE_{CS} + PE_{equiv\ met\ comb} + PE_{equiv\ N2Ocomb} + PE_{equiv\ fug} \qquad \textbf{(4.8)}$$

Calculation of baseline emissions

The baseline emissions will be determined by *ex-post* monitoring of electricity and heat generation, and *ex-ante* calculation of the efficiencies for separate generation of electricty and heat in the baseline situation. The consumption of the fuel avoided in the baseline for the supply of heat is determined as follows:

Annual baseline fuel consumption for heat supply $ABEC_{BF}$ (TJ/yr)

$$ABEC_{BF,th} = \frac{CAHO}{e_b} = CAHO \times FR_{th} \quad (TJ / yr) \qquad \textbf{(3.1)}$$

Where: CAHO = cogeneration system heat output in TJ/yr steam
e_b = boiler efficiency of the existing power station
FR_{th}= fuel rate for heat of the existing power station

The actual baseline fuel consumption for heat supply ($ABEC_{BF, th}$) is determined *ex-post* by monitoring of cogeneration heat output (CAHO) and multiplication with the fuel rate for heat (FR_H) of the existing power station.

a) The baseline CO_2 emissions from combustion of baseline fuel for heat supply are as follows:

Baseline CO_2 emissions from combustion of baseline fuel for heat supply, BE_{th} (tonnes CO_2/yr):

$$BE_{th} = ABEC_{BF} \text{ x } EF_{BF} \qquad \textbf{(3.3)}$$

Where
$ABEC_{FH}$ *(TJ/yr)* = annual energy consumption for heat supply at baseline plant
EF_{BF} *(t CO_2/TJ)* = CO_2 emission factor of the fuel used to generate heat

According to the hierarchy for EF_{BF} as set by the applied AM0014, EF_{BF} will be determined according to the IPCC 2006 guidelines because no specific value from the National GHG inventory is available. Baseline CO_2 emissions from combustion of baseline fuel for heat supply (BE_{th}) is determined by multiplication of actual baseline fuel consumption for heat supply ($ABEC_{BF, th}$) with the CO_2 emission factor of the fuel used to generate heat ($EF_{BF, th}$).

As discussed previously in Section B.3, CH_4 and N_2O emissions are, for conservative reasons, not considered:
b) The baseline methane emissions from combustion of baseline fuel for heat supply are neglected.
c) The baseline nitrous oxide emissions from combustion of baseline fuel for heat supply are neglected.
d) The baseline methane emissions from natural gas production and pipeline leaks in the transport and distribution are neglected.

e) Baseline emissions of CO_2 from electricity supply to industrial plant, that are offset by electricity supplied from cogeneration system

Because PFL is not connected to the power grid, the baseline is the dedicated fossil fuel power plant. The consumption of the fuel avoided in the baseline for the supply of electricity is determined in accordance with the following formulae:

Electricity displaced, that would have to be generated through dedicated fossil fuel power plant
Baseline carbon dioxide emissions for electricity supplied, $BE_{elec\ fossil\ fuel}$ (tonnes CO_2/year):

$$BE_{elec}\left(tonneCO_2 / year\right) = \frac{CEO \times BEF_{elec}}{10^3} \qquad \textbf{(3.11)}$$

Where: *CEO* = Cogeneration Electricity Output (MWh/year), and
$BEF_{elec\ fossil\ fuel}$ = Baseline CO2 emission factor for electricity from the dedicated fossil fuel power plants (kg CO2/MWh)

$$BEF_{elecfossilfuel} = \frac{\sum (PG_{i,n} * SEF_{i,n})}{\sum PG_{i,n}} \qquad \textbf{(3.11a)}$$

Where: $PG_{i,n}$ = Power generated by sources in MWh, by relevant power sources n, sources delivering electricity to the consuming facility
$SEF_{i,n}$ = Specific CO_2 emission factor of the fossil fuel power generation sources n (in terms of kg/MWh), sources delivering electricity to the consuming facility
n = Number of fossil fuel power generation sources

Remark:
Because there is only one dedicated power plant n, the formulae 3.11a can be simplified as follows:

$$BEF_{elecfossilfuel} = SEFi \qquad \textbf{(3.11b)}$$

The specific CO_2 emission factor of the fossil fuel power generation source delivering electricity to the consuming facility $SEF_{i,n}$ is determined as follows:

$$SEF_i\left(kgCO_2 / MWh\right) = FR_{elec} \times EF_{BF} \qquad \textbf{(3.11c)}$$

Where: FR_{elec} *(GJ/MWh)* = fuel rate for electricty of the existing steam turbine power station
EF_{BF} *(kg CO_2/GJ)* = CO_2 emission factor of the fuel used to generate heat

The actual cogeneration electricity output (CEO) is determined by *ex-post* monitoring.

B.6.2. Data and parameters that are available at validation:

Data / Parameter:	**Thermal efficiency or heat rate for steam generation in heat-only mode (baseline)**
Data unit:	% (thermal efficiency boiler e_b), GJ_{NCV}/GJ_{th} (heat rate boiler FR_{th})
Description:	The thermal efficiency for steam generation in heat-only mode, or the heat rate as its inverse value, characterize the efficiency of the current system.
Source of data used:	Default value according to AM0014
Value applied:	91.0 % or 1.10 GJ_{NCV}/GJ_{th}
Justification of the choice of data or description of measurement methods and procedures actually applied :	Selection according to the selected baseline scenario: 3. Industrial plant upgrades the thermal energy generating equipment and therefore increases the efficiency of boiler(s) immediately. (see Section B.3)
Any comment:	-

Data / Parameter:	**Net electric efficiency or net heat rate for electricity generation in condensing mode with existing steam turbines (baseline)**
Data unit:	% (electric efficiency e_{ST}), GJ_{NCV}/MWh_{elec} (heat rate FR_{elec})
Description:	The efficiency for electricity generation in condensing mode, or the heat rate as its inverse value, characterize the efficiency of the current system.
Source of data used:	Calculation with Fichtner's thermodynamic cycle simulation software KPRO® (see Annex 3e)
Value applied:	23.4 % or 15.38 GJ_{NCV}/MWh_{elec}
Justification of the choice of data or description of measurement methods and procedures actually applied :	The electric efficiency / heat rate were calculated with the use of Fichtner's thermodynamic cycle simulation software KPRO® (see Annex 3e), applying number-plate thermodynamic parameters of the steam turbines etc. (see Section B.3). Historic values couldn't be applied because steam generated for steam turbine supply and heat supply is not measured separately.
Any comment:	-

Data / Parameter:	**CO_2 emission factor for natural gas (EF_{NG})**
Data unit:	t CO_2 /TJ
Description:	CO_2 emission factor
Source of data used:	Default emission factor of 2006 IPCC guidelines, Chapter 2 Stationary Combustion, Table 2-2 (energy industries) and Table 2-3 (manufacturing industries and construction)
Value applied:	56.1 t CO_2 /TJ
Justification of the choice of data or description of measurement methods and procedures actually applied :	The Methodology AM0014 sets the following hierarchy for the natural gas emission factor to be chosen: 1. National GHG inventory 2. IPCC, fuel type and technology specific 3. IPCC, near fuel type and technology It has been verified that no specific emission factor other than the IPCC default value is used. Therefore, option "2. IPCC, fuel type and technology specific" has been applied.
Any comment:	-

B.6.3 Ex-ante calculation of emission reductions:

***Ex-ante* calculation of project emissions**

Total annual fuel consumption of the cogen plant is estimated as follows:

$$AEC = (CAHO + CEO) / e_{cogen}$$

Where as:

AEC = total annual fuel consumption of cogen plant in TJ/yr
CAHO = cogeneration system heat output in TJ/yr steam
CEO = cogeneration electricity output in MWh/yr, converted to TJ/yr
e_{cogen} = 91.5 %/100 total efficiency of the cogen plant

Total annual fuel consumption of the cogen plant is estimated as follows:

$$AEC = (3{,}635\ TJ/yr + 661.7\ TJ/yr) / (91.5\%/100) = 4{,}696\ TJ/yr$$

Emission factor for natural gas is taken from published figures in IPCC 2006 guidelines.

Carbon dioxide emissions from natural in the cogeneration system are *ex-ante* calculated as follows, based on the emission factor of natural gas:

PE_{CS} = 4,696 TJ/yr x 56.1 t CO_2 /TJ = 263,446 t CO_2 /yr

Because project emissions of CH_4 and N_2O as well as emissions from leaks by the production and distribution of the natural gas are not considered (see B.6.), the total *ex-ante* project emissions are:

PE_{total} = 263,446 t CO_2e /yr

Ex-ante calculation of baseline emissions
The annual baseline fuel consumption for heat supply $ABEC_{BF}$ (TJ/yr) is determined ex-ante according to equation (3.1) (see B.6.1.), where:
e_b = 91 %/100 boiler efficiency of the existing power station, (see Table 4)
FR_{th}= 3.23 GJ_{NCV}/t_{steam} or 1.10 GJ_{NCV}/GJ_{th} fuel rate for heat of the existing power station, (see Table 4)

Ex-ante estimate of cogeneration system heat output (CAHO): 3,635 TJ/yr (see Table 1)

The *ex-ante* estimate of the fuel avoided in the baseline for the supply of heat is therefore:
$ABEC_{BF}$ = 3,635 TJ_{th}/yr x 1.10 GJ_{NCV}/GJ_{th} = 3,999 TJ_{NCV}/yr

a) The baseline CO_2 emissions from combustion of baseline fuel for heat supply are as follows:

The *ex-ante* baseline CO_2 emissions from combustion of baseline fuel for heat supply are calculated according to equation (3.3):
BE_{th} = 3,999 TJ_{NCV}/yr x 56.1 t CO_2 /TJ = 224,344 t CO_2 /yr

As discussed previously in Section B.3, CH_4 and N_2O emissions are, for conservative reasons, not considered:
b) The baseline methane emissions from combustion of baseline fuel for heat supply are neglected.
c) The baseline nitrous oxide emissions from combustion of baseline fuel for heat supply are neglected.
d) The baseline methane emissions from natural gas production and pipeline leaks in the transport and distribution are neglected.
e) Baseline emissions of CO_2 from electricity supply to industrial plant, that are offset by electricity supplied from cogeneration system

Because PFL is not connected to the power grid, the baseline is the dedicated fossil fuel power plant. The consumption of the fuel avoided in the baseline for the supply of electricity is determined in accordance with formulae (3.11) and (3.11a)/(3.11b):

The actual cogeneration electricity output (CEO) is determined by *ex-post* monitoring. *Ex-ante* estimate of cogeneration system electricity output (CEO): 183.8 GWh/yr (see Table 1)

The specific CO_2 emission factor of the fossil fuel power generation source delivering electricity to the consuming facility $SEF_{i,n}$ is determined *ex-ante* as follows:
SEF_i = 15.38 GJ_{NCV}/MWh_{elec} x 56.1 kg CO_2 /GJ = 862.8 kg CO_2 / MWh_{elec} (see Table 4)

The *ex-ante* calculation of the baseline CO_2 emissions from combustion of baseline fuel for electricity supply are therefore:
BE_{elec} = 183,800 MWh/yr x 862.8 kg CO_2 / MWh_{elec} / 1000 = 158,583 t CO_2/yr

Total *ex-ante* baseline CO_2 emissions are given by the sum of the components as indicated by equation (3.15):

BE_{total} = 224,344 t CO_2/yr + 158,583 t CO_2/yr = 382,927 t CO_2e/yr

Ex-ante calculation of emission reductions
The Emission reductions are calculated as the difference between the baseline and the project emissions on annual basis. Fuel consumption, electricity and heat production of the cogeneration system are metered and monitored (see also Section B7.2).

$$ER = BE_{total} - PE_{total}$$

The total *ex-ante* emission reductions are

ER = 382,927 t CO_2e/yr - 263,446 t CO_2e /yr = 119,481 t CO_2e /yr

B.6.4 Summary of the ex-ante estimation of emission reductions:

Table 11: Estimated amount of emission reductions

Years	Estimation of project activity emissions (tonnes of CO_2e)	Estimation of baseline emissions (tonnes of CO_2e)	Estimation of leakage (tonnes of CO_2e)	Estimation of overall emission reductions (tonnes of CO_2e)
Year 1 (09/2009-12/2009)	87,815	127,642	0	39,827
Year 2 (2010)	263,446	382,927	0	119,481
Year 3 (2011)	263,446	382,927	0	119,481
Year 4 (2012)	263,446	382,927	0	119,481
Year 5 (2013)	263,446	382,927	0	119,481
Year 6 (2014)	263,446	382,927	0	119,481
Year 7 (2015)	263,446	382,927	0	119,481
Year 8 (01/2016-08/2016)	175,631	255,285	0	79,654
Total estimated reductions (1st Crediting period of 7 years)	1,844,122	2,680,489	0	836,367

B.7 Application of the monitoring methodology and description of the monitoring plan:

The monitoring methodology is applicable to this natural gas-based cogeneration project as the conditions explained under B2 are met.

B.7.1 Data and parameters monitored:

According to the monitoring methodology, monitoring involves the following:

- The fuel consumption (natural gas) at the cogeneration system
- Heat production at the cogeneration system
- Electricity production at the cogeneration system
- Fate of the electricity displaced by the project activity since the project activity displaces electricity from a fossil fuel based dedicated power plant

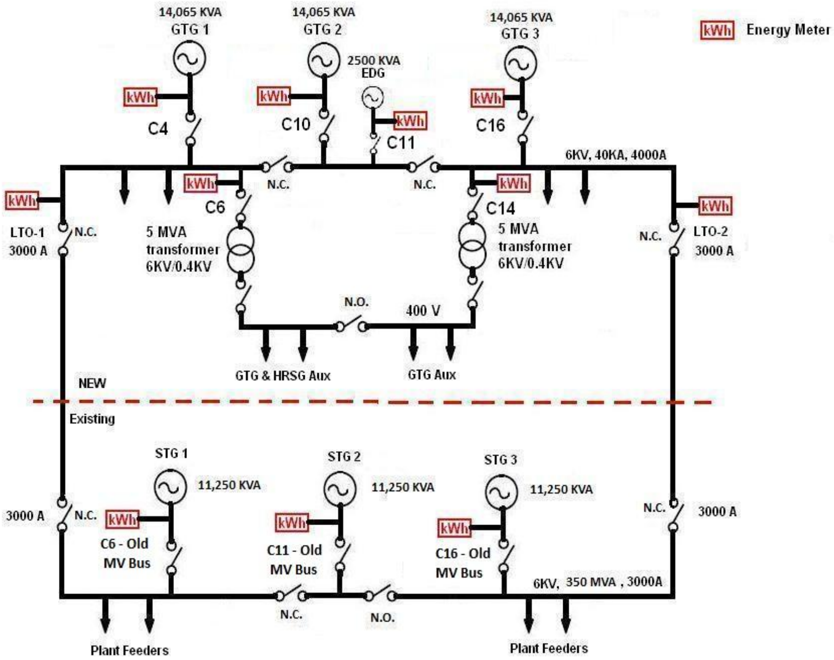
The details of parameters to be monitored are as follows:

Data / Parameter:	**Cogeneration system heat output (CAHO)**
Data unit:	TJ
Description:	The cogen plant produces steam for the supply of the fertilizer complex in the heat recovery steam generators (HRSG), with use of the gas turbine waste heat and additional supplementary firing. This cogeneration system heat output (CAHO) is needed to calculate *ex-post* the baseline fuel consumption for heat supply $ABEC_{BF, th}$, and the Baseline CO_2 emissions from combustion of baseline fuel for heat supply, BE_{th}.
Source of data to be used:	The cogeneration system heat output (CAHO) to the fertiliser complex is determined by an appropriate metering device as the difference of the heat content of the steam minus the heat content of the returned condensate and minus the heat content of the make up water to balance the condensate losses. The steam amount (in t) and its pressure (in Pa) and temperature (in °C), as well as the returned condensate (in t) will be continuously metered. The heat supplied in form of steam to the fertilizer complex will be calculated by use of the metered values.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Steam : 1,242 kt/yr (see Table 1) Equivalent to heat: 3,635 TJ/yr (see Table 1)
Description of measurement methods and procedures to be applied:	Method and equipment: steam flow sensor (compact orifice mass flowmeter), steam pressure sensor, steam temperature sensor, and condensate flow meter, condensate pressure sensor, condensate temperature sensor; heat energy content will be permanently determined by Supervisory Control System Standards used: ISO-5167 (for steam flow) Responsible person: plant manager Calibration procedures: Metering devices are flow calibrated as part of the manufacturing process. The purpose of this calibration is to determine a calibration factor which is applied to the flow calculations as an adjustment to correct for bias error from the ISO-5167 discharge coefficient equations. Accuracy of measurement: +/- 2.5% Measurement interval: continuously
QA/QC procedures to be applied:	Regular monthly sensor and meter checks and signed off records by plant manager; monthly data will be collected and stored both electronically and on paper; before compiling the annual monitoring reports, data will be cross-checked on consistency.
Any comment:	none

QA/QC procedures to be applied:	Regular monthly sensor and meter checks and signed off records by plant manager; monthly data will be collected and stored both electronically and on paper; before compiling the annual monitoring reports, data will be cross-checked on consistency.
Any comment:	none

Data / Parameter:	**Cogeneration system electricity output (CEO)**
Data unit:	MWh
Description:	The cogen plant produces electricity for the supply of the fertilizer complex by the electric generators driven by the gas turbines. This cogeneration system electricity output (CEO) is needed to calculate *ex-post* the baseline fuel consumption for electricity supply $ABEC_{BF, elec}$, and the Baseline CO_2 emissions from combustion of baseline fuel for electricity supply, BE_{elec}.
Source of data to be used:	The net electric energy supplied to the fertilizer complex will be determined (calculated) by using meters of three gas turbine generators as difference of power output of all gas turbines (in MWh) minus sum of auxiliary power consumption of Cogen plant; If A = Total power production of GTGs B = Total auxiliary power consumption at Cogen C = Cogeneration system electricity output = A – B Where A = C4 + C10 + C16 (From meters) B = C6 + C14 (From meters) For reference, see figure 11
Value of data applied for the purpose of calculating expected emission reductions in section B.5	183.8 GWh/yr = 183,800 MWh/yr (see Table 1)
Description of measurement methods and procedures to be applied:	Method and equipment: electricity meters Standards used: according to NEPRA (National Electric Power Regulatory Authority) Grid Code and relevant IECs (note that the plant is not grid connected, and therefore Grid Code otherwise not applicable but used for CDM monitoring) Responsible person: plant manager Calibration procedures: according to meter supplier information with calibration package Accuracy of measurement: +/- 0.2% Measurement interval: continuously
QA/QC procedures to be applied:	Regular monthly sensor and meter checks and signed off records by plant manager; monthly data will be collected and stored both electronically and on paper; before compiling the annual monitoring reports, data will be cross-checked on consistency.
Any comment:	none

Figure 11: Single line Diagram



Data / Parameter:	Natural gas consumption of cogen plant (V_{NG} :)
Data unit:	Nm³
Description:	The cogen plant will use natural gas to be fired in the gas turbines and the supplementary firing of the HRSGs. This natural gas consumption (AEC_{NG}) is needed to calculate *ex-post* the project CO_2 emissions from combustion of fuel by the cogen system, PE_{CS}.
Source of data to be used:	The natural gas consumption of both the gas turbines and the supplementary firing of the HRSGs of the cogen power plant will be metered and recorded.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Natural gas volume: 130.9 10^6 Nm³/yr Equivalent to energy: 4,226 TJ_{NCV}/yr (see Section B.6.3) Gross Calorific Value: 34,353 kJ/Nm³ (= 922 BTU/SCF) Net Calorific Value: 30,971 kJ/Nm³
Description of measurement methods and procedures to be applied:	Method and equipment: gas meters (Compact Orifice Mass Flowmeter) Standards used: ISO-5167 Responsible person: plant manager Calibration procedures: Metering devices are flow calibrated as part of the manufacturing process. The purpose of this calibration is to determine a calibration factor which is applied to the flow calculations as an adjustment to correct for bias error from the ISO-5167 discharge coefficient equations. Accuracy of measurement: +/- 2.5% Measurement interval: gas volume will be recorded continuously; conversion to energy on monthly basis via official calorific value of gas supplier
QA/QC procedures to be applied:	Regular monthly meter checks and signed off records by plant manager; monthly data will be collected and stored both electronically and on paper; before compiling the annual monitoring reports, data will be cross-checked on consistency.
Any comment:	none

Data / Parameter:	Natural gas Calorific values (NCV_{NG} ; GCV_{NG})
Data unit:	kJ/Nm³
Description:	The cogen plant will use natural gas to be fired in the gas turbines and the supplementary firing of the HRSGs. The Net Calorific Value NCV_{NG} will be used to calculate the annual natural gas consumption AEC_{NG} in TJ/yr
Source of data to be used:	a) Monthly invoices by gas supplier (GS). b) Monthly PFL (Pakarab Fertilizers Limited) natural gas analysis report. The Net Value (NCV_{NG}) to be used will be calculated using the following relation; $NCV_{NG} = GCV_{GS} \times (NCV_{PFL} / GCV_{PFL})$ Where; NCV_{NG} = Net Calorific Value of Natural Gas to be used in calculation NCV_{PFL} = Net Calorific Value of Natural Gas (from monthly PFL analysis reports) GCV_{GS} = Gross Calorific Value of Natural Gas (from monthly invoices of gas supplier) GCV_{PFL} = Gross Calorific Value of Natural Gas (from monthly PFL analysis reports)
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Gross Calorific Value: 34,353 kJ/Nm³ (= 922 BTU/SCF) Net Calorific Value: 30,971 kJ/Nm³
Description of measurement methods and procedures to be applied:	Method and equipment: Gas chromatograph Standards used: ISO 6976: Natural gas -- Calculation of calorific values, density, relative density and Wobbe index from composition Responsible person: plant manager Calibration procedures: Certified matching calibration gas mixture is run on Gas Chromatograph using Thermal Conductivity Detector (TCD), peak height/area of each gas is measured and factor is calculated as; F=Standard Concentration value of Gas / (attenuation x peak height/area of Standard gas) Calibration frequency of gas chromatograph: Monthly Measurement interval: official calorific value (GCV_{GS}) of gas supplier provided on monthly basis by invoice for natural gas. Calorific values (GCV_{PFL} and NCV_{PFL}) of natural gas will be measured on daily basis by PFL laboratory and the monthly average values will be used in calculation. Natural gas analysis report will be provided on monthly basis by PFL laboratory.
QA/QC procedures to be applied:	Regular monthly records and cross checks by plant manager; monthly data will be collected and stored both electronically and on paper.
Any comment:	none

Data / Parameter:	Fate of electricity generated by baseline dedicated power plant
Data unit:	MWh
Description:	Represents the level of utilization of the baseline dedicated power plant
Source of data to be used:	On-site check as long as old power plant is not scrapped
Value of data applied for the purpose of calculating expected emission reductions in section B.5	as absolute value and percentage compared to electricity generated by the project activity cogeneration plant
Description of measurement methods and procedures to be applied:	Meter readings
QA/QC procedures to be applied:	Regular monthly meter checks and signed off records by plant manager
Any comment:	The project proponent is aware of the special note included in the monitoring methodology. It is planned to put the existing power plant out of regular operation, and to use it only as back-up plant when the new cogeneration plant as planned or unplanned outages. The project proponent will show in each Verification report the electricity produced by the baseline dedicated power plant, and indicate that during their operation the new co-generation plant has not been available. It will be also shown that the baseline dedicated power plant generation has been reduced by at least the same amount as the electricity generated by the project activity cogeneration plant (which has to be corrected for the increased capacity and demand). If for some reasons, this should not be the case, the credits for the electricity generation will be reduced to the equivalent of excess electricity produced by the baseline dedicated power plant, but takeing the demand increase into consideration. The project proponent will provide such reports as long as the old power plant will not be scrapped. In case the old plant will be scrapped, sufficient evidence will be provided to the Verifying DOE.

B.7.2 Description of the monitoring plan:

Operational data relevant for emission accounting will be logged by operator on daily basis using a Pre-prepared log-sheet form, as part of the data logging system. The log book will be signed and checked by the Unit Manager (Utilities) who will compile the report on weekly basis to determine:

- Cogeneration system heat output (CAHO) to the fertiliser complex.
- Cogeneration system electricity output (CEO) to the fertiliser complex.
- The natural gas consumption V_{NG}/AEC_{NG} at the cogeneration system

The Unit Manager (Utilities) consolidates the above data on monthly basis, and cross-checks them against sales invoices from gas suppliers. The consolidated information will be summarized into a monthly report, checked and signed by the Site General Manager.

Calibration Procedure

The instrumentations installed are new and will/have been calibrated to international standard before commissioning. Regular calibration will be performed on regular basis during the annual maintenance shut-down at the end of first year and subsequent years to all identified instrumentations up to error level of 4% or less for critical devices such as gas meter, electricity meter and heat measurement instruments. Every end of maintenance shut-down, the Unit Manager (Instruments) composes a Calibration Status Report listing all CDM-related instruments, their details, calibration status and expected error.

Archiving of Data
Field data will be stored on computer software, but daily log-sheet will serve as back-up purpose and archived at Project site. All the metered and the calculated parameters and data will be kept on paper for two years and in electronic form until 2 years after end of the crediting period (data on 1st creditin period will be kept until end of 2017 or beyond)..

Monitoring Report
After the end of each calendar year, the project owner compiles data received and arranges the preparation of the Monitoring Report to be sent to the Verifier DOE. During the writing of the monitoring report consistency of data will be checked and clarified.

B.8 Date of completion of the application of the baseline study and monitoring methodology and the name of the responsible person(s)/entity(ies)

Fichtner GmbH & Co. KG, Germany has prepared the baseline and monitoring plan. Fichtner is also a Project Participant.

Completion date:

03 June 2007 (updates: 23 December 2008 and 07 May 2009)

Contact details:

Fichtner GmbH & Co. KG
Sarweystrasse 3/ POB 101454
70191 Stuttgart
Germany

SECTION C. Duration of the project activity / Crediting period

C.1 Duration of the project activity:

C.1.1. Starting date of the project activity:

July 13, 2007 (Order of gas turbines = 1st equipment purchasing contract, see also timeline under B.5.))

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

25 years, including one major overhaul of gas turbines

C.2 Choice of the crediting period and related information:

The project activity will use renewable crediting period.

C.2.1. Renewable crediting period

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

01/09/2009 or the date of registration, whichever is later.

C.2.1.2. Length of the first crediting period:

7 years

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

not applicable

C.2.2.2. Length:

not applicable

SECTION D. Environmental impacts

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

The Pakistan Environmental Protection Act was enacted in 1997 to provide for protection, conservation, rehabilitation and improvement of the environment. It is the basic legislative tool empowering the government to frame regulations for the protection of the environment. For new development projects, the Section 12 of the Act directs that an Initial Environmental Examination, or where the project is likely to cause an adverse environmental effect, an environmental impact assessment be filed with the Environmental Protection Agency (Pak-EPA) for review and approval prior to project construction. The Pak-EPA issued an Environmental Assessment Guideline package in 1997 which included both general and sectoral guidelines. The EIA/IEE regulations were issued in the year 2000 regarding the environmental assessment procedures giving a firm legal status to IEE and EIA. The category of projects for which an IEE or EIA is mandatory has been issued in the Regulations.

The Regulations distinguish in the following three categories:

- Schedule A: List of Projects Requiring an Environmental Impact Assessment (EIA), including:
  Energy
  - Thermal Power Generation over 200 MW
- Schedule B: List of Projects Requiring an Initial Environmental Examination (IEE):
  Energy
  - Thermal Power Generation less than 200 MW
- Schedule C: List of Projects not Requiring an IEE or EIA

As the project activity clearly belongs to Schedule B and will improve the environmental criteria, an IEE will be developed and submitted.

The most relevant environmental criteria for thermal power generation projects are:

- construction phase
- air emissions
- cooling water and waste heat
- effluents
- noise
- global and transboundary impacts.

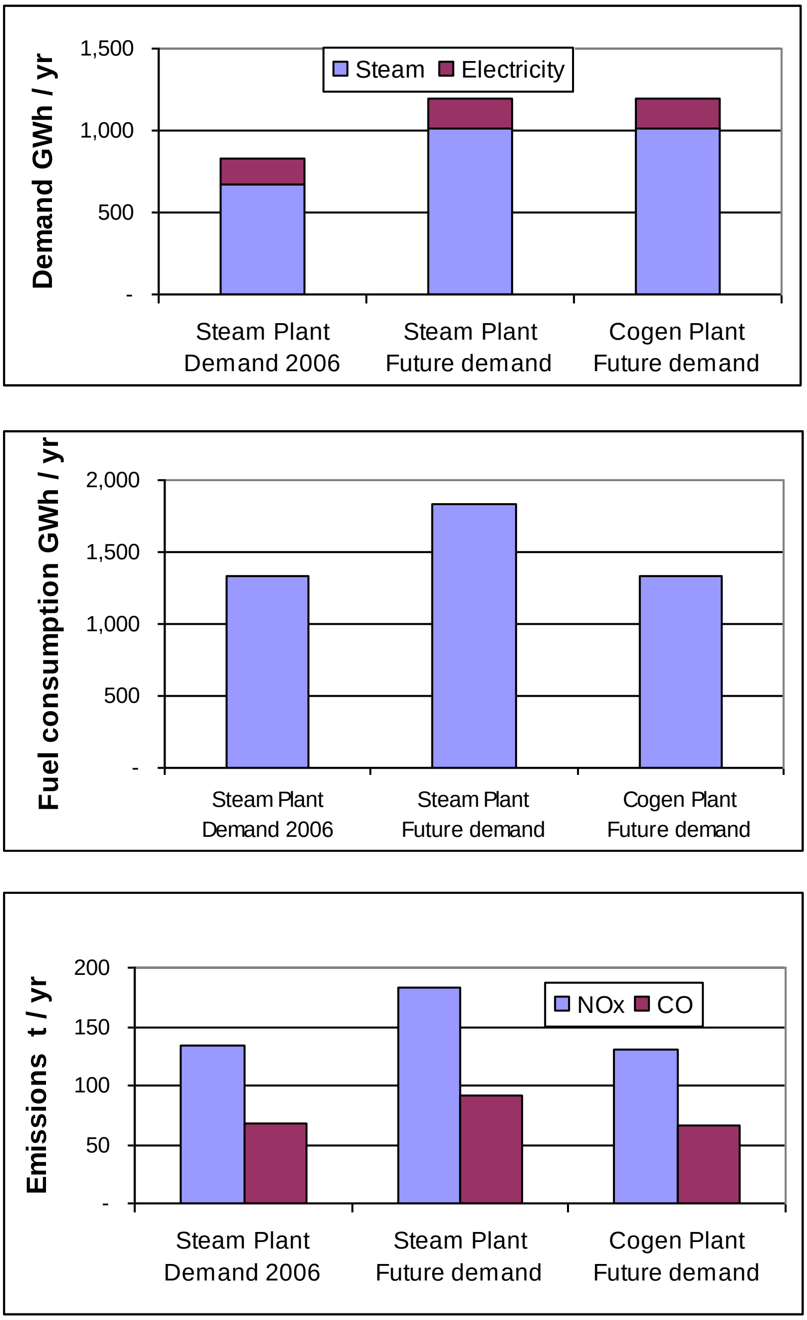
PFL will keep negative impacts during the construction and operating phases as low as reasonably possible. Also, contractors during the construction time will be obliged to minimize environmental impacts.

The most relevant air emissions for gas-fired power stations during operation are:

- Nitrogen oxides (NO_X)
- Carbon monoxide (CO)

Sulphur dioxide (SO_2), particles and dust are minor for gas-firing. The following figure shows the emissions for NO_X and CO. Even if the demand is significantly increasing, these emissions are kept on today's level. Would the project not be implemented, but the separate power and heat generation be continued, these emissions would increase.

Figure 11: Local air emissions



The gas turbine technology does not require any cooling water any longer. Waste heat will be avoided, because it will be used in the heat recovery steam generators (HRSG) for steam production.

The situation for effluents and noise will improve as compared to the current situation.

As a global impact, the reduction of CO_2 emissions is achieved. There are no further transboundary environmental impacts to be expected.

Besides the discussed environmental impacts the project will result in, Pakarab Fertilizers Ltd is committed to perform its social duties. For this reason, the company has developed its social policy. The social activities already in placed are:

- Operation of Pakarab Welfare Trust: The donations and other income of trust is used mainly to help widows, orphans and Jhaze for girls on their marriage. The facility is available to PFL employee only.

- Industrial Home: Females of the area are given training for different trades which help them to improve their skill and standard of living.

- Provision of First Aid Facility: The company provides first aid facility to individuals in case of road side accidents.

- Provision of Fire Fighting Squad: The company has fire-fighting facilities for its use and helps the city civil administration on a day-to-day basis on their demand free of charge.

In connection with the CDM project, Pakarab management has planned the following activities/projects:

- Filtration Plant: A filtration plant will be installed in nearby vicinity to benefit about 10,000 peoples. The major activities of project include a) installation of turbine, b) construction of storage system, c) Construction of operator station, d) Installation of filtration plant. The estimated cost is PKR 0.4 million. Regular operational cost is not included.

- Development of Children Park: A park is being developed in the same vicinity to give the society a healthy environment. The area involved is 125 x 500 yards. Land is being levelled and related activities will be started after wards. Estimated cost is PKR 0.5 million.

- Construction of Community School: An educational institution is planed for 1000 students. This will be up to intermediate level at its final stage. However at initial stage it will be up to middle with 200 students' provision. Estimated cost is PKR 30.0 million.

D.2. If environmental impacts are considered significant by the project participants or the host Party, please 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:

The project activity will have positive environmental impacts (see D1). An Environmental Impact Assessment (EIA) is not required according to Pakistani legislation.

SECTION E. Stakeholders' comments

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

The public CDM stakeholder consultation meeting was held on 7th June, 2007 at 11:00 am outside the factory gate of Pakarab Fertilizer Ltd.. The public was invited by means of several newspaper announcements. The aim of the meeting as indicated in the announcements was to introduce the public to the Co-Generation project. In Annex 5 the newspaper coverage of the event, the Minutes of Meeting and the List of participants are presented.

The meeting started with a recitation of the Holy Quran. Next, the State Secretary Ammanull Khan Niazi informed the audience about the purpose of the meeting and highlighted that the same was announced in advance through print media. It was said that Pakarab has developed the project in light of the CDM and thus is in the process to prepare for the necessary steps to register the project as CDM project.

Afterwards, the project co-ordinator and Director Operation, Mr Saleem Zafar took over and welcomed the audience on behalf of Pakarab being the project owner. He provided some background information on the project and explained how this project is connected to the CDM.

In his and some of his colleagues speeches that followed, the following key issues were presented to the audience:

- The issue of global warming and its connection to the emission of greenhouse gases was introduced.

- The CDM was explained. It was said that the CDM is a project-based mechanism that has been established under the Kyoto Protocol in 1997 to promote investment in projects that either reduce and/or sequester emissions of greenhouse gases in developing countries. The CDM has three stated objectives: a) to assist Parties not included in Annex I (i.e. developing countries) in achieving sustainable development; b) to contribute to the ultimate objective of the Convention to stabilise greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system; and c) to assist Parties included in Annex I (developed countries) in achieving compliance with their quantified emission limitation and reduction commitments under Article 3 of the Kyoto Protocol. Thus, the CDM is a mechanism under the Protocol that promotes partnerships between developed and developing countries. It was further explained that host countries for CDM projects have to be signatories to the UN Framework Convention on Climate Change (UNFCCC) and the Kyoto Protocol. Pakistan has signed both documents and thus can participate in the CDM as a host country.

- The operation of the NO_x and N_2O abatement plant for nitric acid as implemented on the fertilizer complex was described to the public. Pakarab Fertilizer Ltd. has successfully implemented the "Catalytic N_2O Abatement Project in the Tail Gas of the Nitric Acid Plant of the Pakarab Fertilizer Ltd (PVT) in Multan, Pakistan", which was registered as CDM project on 5 November 2006.

- The audience was informed about the planned new co-generation plant, that has been developed as CDM project and for which CDM registration will take place very soon. Regarding the present project, Pakarab could have fulfilled its growing power and steam demand of the industrial complex by setting up a new boiler in the existing power house as the complex is not connected to the public grid. Instead, Pakarab opted for a new co-generation plant to be able to produce power and steam at highest possible efficiency and lowest emission levels. The new plant is designed as to cover almost all required power and steam demands of the fertiliser complex. The existing plant will only be used as backup or in emergency cases should the co-generation be not available.

- The CO_2 emission reduction potential was explained. By operating the new co-generation plant, primarily CO_2 emissions can be reduced compared to the baseline situation. As baseline scenario the existing power plant would continue to supply electricity and heat to the fertiliser complex. In order to meet the future demand, however, an additional boiler of the same size as the existing would have to be installed. The overall CO_2 reduction potential through the anticipated project will contribute to mitigate global warming.

E.2. Summary of the comments received:

After informing and explaining the project to the public, the panel then opened the interactive session and invited the public to put forward their questions and comments. The questions were put forward by the audience.

Question 1:	What is CDM exactly? Can you provide some practical examples?
Question 2:	How would the proposed new plant be efficient in having an effect on global warming?
Question 3:	How will this project Pakarab intends to implement affect the public besides the environment?
Question 4:	Has the project national benefits and if so, what are they?

No objections against the project were voiced at the meeting.

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

Pakarab represented by the panel speakers addressed the above voiced questions as follows:

Answer to question 1:

The CDM can be understood as a method or way to lead to a cleaner environment. For instance one can use for power and steam generation fuel types that produce less smoke, result in fewer greenhouse gas emissions like CO_2 and produce fewer other polluting gases, like e.g. SO_2 and particulate matters. Also, technology can be implemented, which efficiently converts energy resources into power and/or steam for running an industrial process. Basically, this type of project is proposed by Pakarab as CDM project. A good example is also the implementation of a technology that destroys laughing gas (N_2O), which is also a greenhouse gas contributing to warming the earth. This technology is commonly known as N_2O abatement facilities at nitric acid plants. The N_2O abatement technology is to introduce catalytic decomposition equipment at the tail gas downstream after the HNO_3 absorber and before the stack. N_2O is decomposed to N_2 and O_2, which both are no greenhouse gases.

This project type has also be implemented by Pakarab and is registered as CDM as mentioned before. Another project type would be capturing greenhouse gas emissions thus avoiding the venting of these gases into the atmosphere without control and use. This could be for instance capturing methane (CH_4) from organic waste management processes or landfills. One can also consider the replacement of thermal powers station with larger hydropower stations or wind farms thus introducing more renewable energy sources in the national grid.

The CDM thus addresses all project types or measures that lead to a reduction of greenhouse gases like CO_2, CH_4 and N_2O. It must be demonstrated however, that in the absence of the proposed project activity these emission reductions would not have taken place. The CDM provides basically an incentive to convert business-as usual practices into practices that result in fewer or even zero greenhouse gas emissions.

<u>Answer to question 2:</u>
Global warming is a phenomenon, in which the greenhouse gases in the atmosphere have an effect of increasing the temperature of the ambient air. As the proposed project activity can reduce gas consumption and greenhouse gas emissions, the project would have a positive effect in mitigating global warming, even if the relative contribution on a global scale may be quite small.

<u>Answer to question 3:</u>
The public will benefit from new job opportunities that will be created, in particular for the time span of construction of the power plant. Construction period an associated period for new available jobs will be between 18 to 20 months.

<u>Answer to question 4:</u>
The Pakistan government has to approve the project. Currently, national governmental approval is requested by Pakarab. By approving the project as CDM project activity, the government shows its willingness to support the development pathways the CDM can offer to developing countries. Further, as the greenhouse gas emission reductions the project will achieve, Pakarab can sell these to international carbon investors and thus additional foreign currency can be transferred into Pakistan, which is in the interest of the government. Also, modern state-of-the art cogeneration technology is transferred to Pakistan.

The benefits the project brings about are:

- Reliability of plant for smooth operation
- Energy conservation
- Job opportunity to near by community during erection
- Low pollution in the area because of less fuel consumption
- Foreign exchange because CDM project
- Low noise level because of silencer fitting in high flow area