



**CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-PDD)
Version 02 - in effect as of: 1 July 2004)**

CONTENTS

- A. General description of project activity
- B. Application of a baseline methodology
- C. Duration of the project activity / Crediting period
- D. Application of a monitoring methodology and plan
- E. Estimation of GHG emissions by sources
- F. Environmental impacts
- G. 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

The following Annexes would be added after methodologies have been approved, and prior to validation.

Annex 5: Letter from the Argentina CDM Office

Annex 6: Technical information of the equipment before project

Annex 7: Technical information of the equipment after project

Annex 8: Sustainability indicators

Annex 9: Quality control and monitoring

**SECTION A. General description of project activity****A.1 Title of the project activity:**

>>

Shell Cogeneration Project

Version 1,
June 1, 2005.**A.2. Description of the project activity:**

>>

The project activity primarily aims at reducing GHG emissions through improvements in cogeneration at an industrial facility, a refinery located in Buenos Aires, Argentina.

Prior to project implementation, electricity and steam were generated at the industrial site using a number of steam turbines and boilers. This equipment operated using a combination of asphalt, fuel oil and “fuel gas” which is a mixture of refinery gas and natural gas. With this configuration, the refinery meets all its requirements for heat and most of its electricity needs. Electricity is purchased from the network to meet the remaining demand.

The project consists of investment to replace some of the steam turbines with a gas turbine. The gas turbine would operate entirely on natural gas. As a consequence of project implementation, electricity generation capacity would be considerably increased so that excess electricity would be sold to the power grid. The industrial plant would thus shift from being a purchaser to being a seller of electricity. Moreover, there will be considerable reduction in the use of asphalt, fuel oil and refinery gas, and an increase in natural gas consumption.

The project sponsor is part of Shell, a global group of energy and petrochemicals companies, operating in over 145 countries. The specific project is at a petroleum refinery located in Buenos Aires, Argentina. Shell Compañía Argentina de Petróleo S.A. (Shell CAPSA) has operated its refinery in Argentina since 1931. It is the only refinery of the Shell Group in South America and produces LPG, gasoline, diesel, solvents, light diesel (called “gas oil” in Argentina), bunker fuel oil, basic lubricants, and asphalt.

Prior to project implementation, the plant used asphalt and other petroleum fuels (together with a small amount of natural gas purchased from the natural gas pipeline) to generate steam and electricity to meet refinery needs. Since electricity generated on site did not meet demand, additional electricity was purchased through the power grid.

The project involves the installation of a gas turbine cogeneration system that would generate electricity to meet all of the refinery requirements, and sell the excess generation through the power grid. Project implementation would reduce GHG emissions by an estimated 107,222 tonnes CO₂-equivalent per year.

The gas turbine operates on natural gas, so there would be reduced consumption of higher-carbon-content petroleum fuels and increased consumption of natural gas, a low-carbon fuel. Moreover, this shift in fuels used at the refinery is also expected to reduce airborne pollutants and improve air quality at and around the refinery.

Thus, the project brings environmental benefits, contributing to sustainable development objectives of Argentine Government, in accordance with the General Environmental Law, the National Law N° 25,675. (<http://www.medioambiente.gov.ar/mlegal/marco/ley25675.htm>)



The project is expected to obtain the written approval of the Argentina CDM Office for voluntary participation, confirming that the project supports sustainable development.

A.3. Project participants:

>>

Name of Party involved (*). (host) indicates a host Party)	Private and/or public entity(ies) project participants (*) (as applicable)	Kindly indicates if the Party involved wishes to be considered as project participant (Yes/No)
Shell Compañía Argentina de Petróleo S.A. (host)	Private entity. Project Developer.	Yes
Shell Trading International Limited	Private entity. Annex I country participant: United Kingdom	Yes
Showa Shell Sekiyu KK	Private entity. Annex I country participant: Japan.	Yes
MGM International, Ltda.	Private entity. PDD Consultant.	No

(*) In accordance with the CDM modalities and procedures, at the time of making the CDM-PDD public at the 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.

See Contact Information in Annex 1 to this PDD.

Official contact: Marco G. Monroy
MGM International Ltda.
Junín 1655 1° B
C1113AAQ Buenos Aires, Argentina
54.11.5219.1230
marcogmonroy@mgminter.com

A.4. Technical description of the project activity:**A.4.1. Location of the project activity:**

>>

A.4.1.1. Host Party(ies):

>>

Argentina

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

>>

Buenos Aires Province

A.4.1.3. City/Town/Community etc:

>>

Dock Sud

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

>>

The project is located at Dock Sud industrial area, at the south of Buenos Aires Autonomous City, in Buenos Aires Province.

Buenos Aires City, the capital of the Argentinean Republic (Figure 1), is located in the centre of the country, bounded by La Plata River in the east. Its area is 200 km² and it is home to 2.8 million people. (According to the 2001 Census).

The city is surrounded, from the south to the north, by a big urban and suburban area called Gran Buenos Aires (Figure 2), with a population of 8.7 million and 3,680 km² of area. The industrial complex of Dock Sud is located in Gran Buenos Aires, in Avellaneda township. (Figures 3 and 4).



Figure 1: Map of Argentina

Figure 3: Map showing Dock Sud Industrial area location



Figure 4: Dock Sud Industrial Area

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

>>

The most likely category would be “(1) Energy industries (renewable / non-renewable sources)” although being a refinery “(5) Chemical industry” is another possibility.

A more specific category of project activity might be “industrial cogeneration”.

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

>>

A gas turbine based cogeneration system would be introduced to offset fuel used in boilers and electricity purchased from the power grid. The gas turbine would operate on natural gas, so that there will be increased use of this fuel, and reduced consumption of petroleum fuels, as a result of project implementation.

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:

>>

The project involves the installation of a gas turbine generation system at a refinery in order to generate electricity. The waste heat from the gas turbine would also be used to supply part of the demand for steam at the power plant. The remainder of the steam demand would be met by equipment and installations existing prior to project implementation. As a result, there would be an improvement in plant efficiency in a thermodynamic sense, while generated electricity in excess of plant requirements would be supplied to the power grid, offsetting generation and emissions elsewhere. The installation of the natural-gas-fired gas turbine also involves fuel switching, whereby more carbon intensive petroleum fuels are replaced by natural gas, which has a much less carbon intensity. As a consequence of all aspects of project implementation, overall emissions of CO₂, and to a minor extent other GHGs, would be reduced, compared to the baseline situation.

The methodology analyses project additionality using the “Tool for demonstration and assessment of additionality,” published as Annex 1 to the 16th Meeting Report of the CDM Executive Board (October 2004). Details are provided in Section B.3 of this PDD. We show that there are basically three categories of options: (a) the business-as-usual option involving the continued use of boilers and steam turbines; (b) the incorporation of a gas turbine based cogeneration together with the continued use of some of the boilers and some of the steam turbines undertaken by the project sponsor; and (c) the installation of a cogeneration system by a third party that would sell heat and electricity to the refinery and excess electricity to the power grid. In each of the second and third categories of options, there are any number of actual options, differing in the capacity of the steam and gas turbines involved. Nevertheless, these two categories are qualitatively different from the first.

All three alternative options would meet applicable laws and regulations.

Additionality is established principally through an analysis of barriers, identifying three categories of barriers: (a) macroeconomic (the macroeconomic situation in Argentina inhibits all investments since the devaluation in early 2002); (b) wholesale power market rules (which have made investments in power generation not profitable since 1997); and (c) institutional barriers (which inhibit cogeneration in Argentina). Each are discussed in detail in Sec. B.3.



Our analysis indicates that the proposed project faces a number of barriers and its implementation would not have been considered at all if not for the possibility of emissions reductions credits. The third option, whereby a third party would invest in and install a cogeneration system at the refinery faces even more barriers. Thus, the proposed project is additional, and the continuing with current operating conditions is the baseline.

Estimation of the reduction in GHG emissions depends on two considerations: (a) the emissions factors and quantities of the fuels used at the refinery, in the baseline and project scenarios and (b) the emissions factor of the power grid connected to the refinery. The baseline methodology for making this determination is a new methodology being submitted with this PDD. This new methodology incorporates ACM0002 ("Consolidated baseline methodology for grid-connected electricity generation from renewable sources") in order to determine the emissions reductions through power supplied by the cogeneration plant to the interconnected grid. The new methodology allows for the use of the small-scale methodology I. D "Renewable electricity generation for a grid." when the power sent to the grid is less than 15 MW. This latter option is not used in this PDD. While the project does not involve renewable electricity generation, unlike these approved methodologies, the electricity supplied by the cogeneration facility to the grid offsets emissions elsewhere in the power grid in the same manner as if this generation were renewable. This has already been recognized by the Meth Panel, who incorporated methodology ACM0002 and the "small-scale" methodology I.D into AM0014, which involves natural-gas based cogeneration.

A.4.4.1. Estimated amount of emission reductions over the chosen crediting period:

>>

The *ex-ante* emissions reductions are estimated to be 107,222 tonne CO₂e/year for the crediting period of 7 years, which may be renewed. Note that actual emissions reductions will be based on monitored data and may differ from this estimate.

Year	Annual estimation of emission reduction in tonnes of CO ₂ e
Year 1	107,222
Year 2	107,222
Year 3	107,222
Year 4	107,222
Year 5	107,222
Year 6	107,222
Year 7	107,222
Total estimated reductions (tonnes of CO₂e)	750,554
Total number of crediting years	7
Annual average over the crediting period of estimated reductions (tonnes of CO₂e)	107,222

A.4.5. Public funding of the project activity:

>>

No funds from public national or international sources are involved in any aspect of the proposed project.

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

>>

This project proposes a new methodology denominated: “Cogeneration at an industrial facility”.

This new methodology incorporates ACM0002 “Consolidated baseline methodology for grid-connected electricity generation from renewable sources.” An alternative methodology for power generation from renewable energy sources is also contemplated, applicable to power output below 15 MW, is the small-scale methodology I. D “Renewable electricity generation for a grid.” The new methodology adapts the “Tool for demonstration and assessment of additionality” (published as Annex 1 to EB 16 Report, Oct. 2004). The new methodology also uses equations for determining emissions at an industrial facility similar to those in the approved methodology: AM0008 “Industrial fuel switching from coal and petroleum fuels to natural gas without extension of capacity and lifetime of the facility.”

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

>>

The methodology was selected in order to be applicable to projects such as that proposed here.

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

>>

The methodology is based on the case where baseline is defined in terms of “existing actual or historical emissions, as applicable”, as defined in paragraph 48 (a) of CDM modalities and procedures.

The first step in applying the methodology is an evaluation of project additionality (sec. B.3, below).

Then an appropriate project boundary is established (sec. B.4).

Baseline and project emissions basically depend on (1) fuel consumption within the project boundary and the carbon content of the fuels used, (2) electricity purchases by and sales from the refinery to the power grid and (3) emissions factor of grid-connected power plants. Fuel consumption and electricity purchases and sales can be readily measured; the carbon content of fuels are known. The main difficulty is in determining the emissions factor for grid-connected power plants. We applied the ACM0002 to determine this and the difficulties stem from the data requirements of this methodology. The calculations are shown in Annex 3.

The methodology specifies that baseline and project emissions, determined from thermodynamic analysis, be the basis for ex-ante emissions reductions estimates reported in this PDD.

Actual emissions reductions are determined from monitored data following project implementation, and dynamic baseline emissions determined from monitored data as well as performance indicators of the industrial plant prior to project implementation, defining baseline conditions.



The key information and data used to determine the baseline scenario (variables, parameters, data sources, etc.) are listed in the following table.

Key parameter	Values	Data sources
FC_i	Fuel consumption for each fuel i	Monitored
$EF_{asphalt}$	carbon dioxide emission factor per unit energy of <i>asphalt</i> (e.g. tCO ₂ e/GJ) (combustion)	National Inventory or direct measurement or IPCC default values
EF_{fuel_oil}	carbon dioxide emission factor per unit energy of <i>fuel oil</i> (e.g. tCO ₂ e/GJ) (combustion)	National Inventory or direct measurement or IPCC default values
EF_{fuel_gas}	carbon dioxide emission factor per unit energy of <i>fuel gas</i> (e.g. tCO ₂ e/GJ) (combustion)	National Inventory or direct measurement or IPCC default values
$EF_{natural_gas}$	carbon dioxide emission factor per unit energy of <i>natural gas</i> (e.g. tCO ₂ e/GJ) (combustion)	National Inventory or direct measurement or IPCC default values
$MEF_{asphalt}$	methane emission factor per unit energy of <i>asphalt</i> (e.g. tCH ₄ /GJ) (combustion)	IPCC default values
MEF_{fuel_oil}	methane emission factor per unit energy of <i>fuel oil</i> (e.g. tCH ₄ /GJ) (combustion)	IPCC default values
MEF_{fuel_gas}	methane emission factor per unit energy of <i>fuel gas</i> (e.g. tCH ₄ /GJ) (combustion)	IPCC default values
$MEF_{natural_gas}$	methane emission factor per unit energy of <i>natural gas</i> (e.g. tCH ₄ /GJ) (combustion)	IPCC default values
$NEF_{asphalt}$	nitrous oxide emission factor per unit energy of <i>asphalt</i> (e.g. tN ₂ O/GJ) (combustion)	IPCC default values
NEF_{fuel_oil}	nitrous oxide emission factor per unit energy of <i>fuel oil</i> (e.g. tN ₂ O/GJ) (combustion)	IPCC default values
NEF_{fuel_gas}	nitrous oxide emission factor per unit energy of <i>fuel gas</i> (e.g. tN ₂ O/GJ) (combustion)	IPCC default values
$NEF_{natural_gas}$	nitrous oxide emission factor per unit energy of <i>natural gas</i> (e.g. tN ₂ O/GJ) (combustion)	IPCC default values
$GWP(CH_4)$	global warming potential of CH ₄	set as 21 tCO ₂ e/tCH ₄ for the 1 st commitment period
$GWP(N_2O)$	global warming potential of N ₂ O	set as 310 tCO ₂ e/tN ₂ O for the 1 st commitment period
$NPES$	Net electricity sales to grid in project scenario	Monitored
$NBEP$	Net electricity purchases from grid in baseline scenario	
$EF_{elec\ gen}$	baseline “combined margin” emission factor for grid electricity generation (e.g. kg CO ₂ e/MWh)	Calculated from CAMMESA plants information.
EF_{OM}	CO ₂ operating margin emission factor for	



	grid	
EF_{BM}	CO ₂ build margin emission factor for grid	
$F_{i,y}$	Amount of each fossil fuel consumed by each power source / plant	
$COEF_i$	CO ₂ emission coefficient of each fuel type i	
$GEN_{j/k/n,y}$	Electricity generation of each power source / plant j, k or n	
<i>Text</i>	Identification of power source / plant for the OM	
<i>Text</i>	Identification of power source / plant for the BM	

For dynamic baseline emission determination the following data will also be needed:

Key parameter	Values	Data sources
EG	Baseline electricity generation in the BRPS, MWh	Calculated in dynamic baseline procedure
H	Baseline total heat output of the BRPS (equal to refinery steam demand), GJ measured as total steam enthalpy.	Calculated from monitored values of steam output following project implementation. Total enthalpy in dynamic baseline is equal to total enthalpy in project.
σ_{elect}	Baseline (historical) BRPS specific electricity generation, MWh / GJ of steam enthalpy	Value calculated from average power output and average steam output, using data on for 3 years prior to project implementation
EP	Baseline electricity purchase from the grid, MWh	Calculated in dynamic baseline procedure
ED	electricity demand of the refinery, MWh	Monitored following project implementation. Electricity demand in dynamic baseline is equal to project electricity demand
FC_{total}	total fuel consumption in the BRPS, ton SRF	Calculated in dynamic baseline procedure
λ_{FC}	Baseline (historical) BRPS specific fuel consumption for steam generation, ton SRF / GJ of total steam enthalpy	Value calculated from average fuel consumption and average steam output, using data for 3 years prior to project implementation
$FC_{asphalt}$	Baseline asphalt consumption in the BRPS	Calculated in dynamic baseline procedure
FC_{fuel_gas}	Fuel gas consumption in the BRPS	Calculated in dynamic baseline procedure
$FC_{fueloil}$	Fuel oil consumption in the BRPS	Calculated in dynamic baseline procedure
$f_{asphalt}$	Baseline (historical) proportion of asphalt used in the fuel mix	Value calculated from consumption data of each fuel for 3 years prior to project implementation
$f_{fuel\ gas}$	historical proportion of fuel gas used in the fuel mix	Value calculated from consumption data of each fuel for 3 years prior to project implementation



$f_{\text{fuel oil}}$	historical proportion of fuel oil used in the fuel mix	Value calculated from consumption data of each fuel for 3 years prior to project implementation
-----------------------	--	---

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:

>>

In October 2004, the CDM Executive Board published a “Tool for demonstration and assessment of additionality” (Annex 1 of the CDM EB, 16th meeting report). This document in effect interprets the requirements specified in the Marrakesh Accords of the UNFCCC with respect to the operation of the Clean Development Mechanism.¹

The tool has been adapted for its application for the project activities covered by the new methodology submission that accompanies this PDD, within the NMB (new baseline methodology).

The tool consists of Steps 0 through 5.

Step 0 is applicable to project activities that have started before registration. This is the case for the Shell Cogeneration project. The project started operation in mid 2003. Step 0 requires that evidence be publicly provided to show “that the incentive provided by the CDM was seriously considered in the decision to proceed with the project activity”.

As a global energy company providing more than 3% of the world’s oil and gas, Shell has been acutely aware of the climate change issues surrounding the burning of fossil fuels. For over two decades, Shell has been involved in activities to support biomass and other renewable energy sources, which generate little or no emissions of carbon dioxide. The current web page includes a section on sustainable development, which includes “helping the world gradually shift to a low-carbon energy system by providing more natural gas, and lowering the costs of alternatives like wind, solar power and fuels from plants”.

All activities undertaken by Shell include environmental, social and health impact assessment. This assessment leads the identification of energy efficiency, cleaner energy sources, and other measures to reduce the environmental impact of Shell activities. Moreover, climate change considerations are a part of Shell decision-making. Shell keeps up with developments with respect to international treaties and government policies to mitigate climate change. Shell policy can be found at this website:

<http://www.shell.com/climate>

Besides the publicly stated policies of the Shell Group, there are internal guidelines requiring that all project investments consider the economics of GHG emissions. Shell companies assume emitting man-made greenhouse gases (GHGs) will bear a cost, and that reducing GHGs will result in a revenue. This cost or revenue (depending on the jurisdiction) is factored into their project designs and investment decisions. A summary of Shell’s Carbon pricing policy can be found at:

http://www.shell.com/home/Framework?siteId=royal-en&FC2=/royal-en/html/iwgen/environment_and_society/key_issues_and_topics/issues/climate_change/zzz_lhn.html&FC3=/royal-en/html/iwgen/environment_and_society/key_issues_and_topics/issues/climate_change/carbon_pricing_in_our_business.html

¹ Decision 15/CP.7. Principles, nature and scope of the mechanisms pursuant to Articles 6, 12 and 17 of the Kyoto Protocol.



For the specific project in question, Shell Cogeneration Project, a so-called Group Budget Proposal was prepared, as is customary for evaluating project economics. This report provides a brief technical description of the project and summarises the conclusions of the financial analysis. The report includes estimates of reduced CO₂ emissions, among other environmental benefits. The sensitivity analysis of project economics considers possible variations in the price of crude petroleum, electricity price, maintenance costs, *as well as to “carbon credits” from CO₂ emission reductions*. This latter item is denominated “Sensitivity 6”. The Group Budget Proposal was prepared in May 2001, long before project implementation, and confirms that potential revenues from GHG emissions reduction was a key component of this analysis. The Group Budget Proposal includes confidential information on project economics, which are not used to demonstrate project additionality. This document is included as an Annex to this PDD and will be made available only to the Designated Operational Entity (DOE) for Validation purposes. The DOE will not disclose it to any third parties, but is required to forward a copy to the UNFCCC Secretariat for record keeping, under the strict understanding that this Annex will not be available for public comments.

The argument presented above and the supporting documentation means that the Shell Cogeneration Project meets Step 0 of the Additionality tools.

Step 1 of the tools (Identification of alternatives to the project activity consistent with current laws and regulations) comprises a number of sub-steps:

Sub-step 1a. Define alternatives to project activity.

The new baseline methodology adaptation of the additionality tool reduces the possible alternatives for consideration to the following:

1. The industry continues to generate thermal energy and power using existing equipment using the same combination of fuels as in the recent past.
2. (Project activity) The project proponent installs or increases the cogeneration capacity using steam turbines, gas turbines, internal combustion engines or other technologies, using the waste heat to meet on-site thermal energy demand. Any combination of fuels would be admissible as variants on this alternative. Electricity generated would be used at the industrial site and excess electricity would be exported through the grid. This is indeed the project activity, so that this alternative implies undertaking the activity without CDM registration.
3. A third party installs cogeneration capacity at the industrial facility, of any magnitude, with any technology and fuel, selling thermal energy and electricity to the industry and selling any excess electricity through the grid.

Third-party installation of a cogeneration system is not a realistic alternative for two reasons: a refinery is a very large, specialized operation, where a third party (e.g. an Energy Services company) can offer no competitive advantages with respect to the project proponent themselves undertaking the project. The project proponent is likely to have the know how necessary, and, being a large multinational company, is also more likely to have better access to financing.

Prior to project installation, the boiler house at Shell CAPSA Refinery at Dock Sud, Buenos Aires, had boilers and steam turbines, providing all the steam requirements and some of the electricity requirements for refinery operations. Electricity was also purchased from the public supply to meet refinery requirements.

The alternatives are thus reduced to:



1. Operating the boiler house with existing equipment, continuing to purchase electricity from the power grid, and burning petroleum fuels, as well as some natural gas purchased from the gas pipeline.
2. The proposed project, which comprises the purchase of a 25-MW gas turbine to operate on natural gas and a heat recovery steam generator to use waste heat from gas turbine exhaust to generate steam. Some of the steam turbines currently operating would not need to be operated, because all of the heat and power would be provided by the equipment acquired. Indeed, more electricity would be generated than required by the refinery, so excess electricity would be sold to the power grid. Since the gas turbine operates on natural gas, the refinery would purchase this fuel from the gas pipeline, and stop using a combination of petroleum fuels. The thermodynamic efficiency of the heat and electricity supply would be improved and carbon dioxide emissions will fall.

While the project activity might have involved other cogeneration technologies and fuel combinations, and those alternatives also need to be considered as possible baselines. However, these variants are qualitatively similar to the project alternative, for reasons that are explained in the associated baseline methodology.

Moreover, these were the only alternatives considered by Shell prior to its investment decision, and we need only consider the two cases listed above.

Sub-step 1b. Enforcement with applicable laws and regulations

All alternatives considered by Shell, including the continued operation of the current equipment configuration, are intended to meet all applicable laws and regulations. The project activity is no way implied as required to meet any regulations. Thus, additionality is not lost because of this sub-step.

Our adaptation of the “Tool for the demonstration and assessment of additionality” then skips Step 2 (Investment Analysis) and continues with Step 3 (Barrier Analysis), for reasons explained in the baseline methodology

Step 3 is Barrier Analysis.

We apply this Step for this project. We are required to show that the proposed project activity faces barriers that:

- (a) Prevent a wide spread implementation of this activity and thus preventing the baseline scenarios from occurring; and
- (b) Do not prevent a wide spread implementation of at least one of the alternatives.

Step 3 also comprises two Sub-steps to analyse these two questions. However, in this case, we have shown above that there are only two basic alternatives, the project and the baseline. Thus, it is a question only of Sub-Step (a) comparing project and baseline, since there are no other alternatives to consider.

Sub-step 3a. Identify barriers that would prevent a wide spread implementation of the proposed project activity

We are required to establish that there are barriers that would prevent the proposed project activity from being carried out if the project were not registered as a CDM activity. Such barriers may include, among others:

- 1) Investment barriers



- 2) Technological barriers
- 3) Barriers due to prevailing practice
- 4) Other barriers

We will show the project activity faces *investment barriers* that all power generation face in Argentina, as well as *institutional barriers* which inhibit cogeneration in Argentina. Each are discussed below.

Investment barriers

The “Tool for the demonstration and assessment of additionality” mentions investment barriers “other than the economic/financial barriers in Step (2), e.g.:

- Real and/or perceived risks associated with the unfamiliar technology or process are too high to attract investment
- Funding is not available for innovative projects

In considering investment barriers, we have to place ourselves in the macroeconomic context of Argentina. Following several years of recession, the “country risk” reached values above 2000 by year-end 2001. A country risk of 2000 means that the interest rates would be 20 percentage points above international reference values such as LIBOR. At year-end, Argentina declared a “default” on its debt repayment commitments. Shortly afterwards, early in January 2002 (after there had been four changes of president in little over a week), the new government announced an end to the 10-year long era when the Argentine Peso was traded at par with the US\$. The speculation that followed led the exchange rate to reach over 4 Pesos to the US\$. Since then, the value has come down, and is currently around 3 Pesos to the US\$. During all this period, the “country risk” reached astronomical values.

The reduction in money supply even before 2001 caused many provincial governments as well as the national governments to issue secondary currency, nominally called bonds, but which looked like and were denominated as currency notes, in order to make payments to government employees and suppliers. These pseudo-currencies were widespread so that by the end of 2001, many stores accepted a wide range of these “currencies” even those belonging to other provinces. Before year-end 2001, the government sharply bank accounts were frozen and withdrawals from bank accounts were rationed, typically to 200 Pesos per week (equivalent to 200 US\$ up to the end of 2001.) In early 2002, most bank deposits were frozen, dollar accounts converted to Pesos at a rate much lower than the market exchange rates, etc.

Long before this, no capital was available among domestic investors. Foreign investors had also largely disappeared in 2001 as the country risk reached and stayed at high values. The investment climate has remained unchanged until now.

If the investment climate in general deteriorated from 2001 on, it was even worse for electricity generation, and from much earlier.

Following deregulation in 1992, electricity generation is a “competitive” enterprise in Argentina. Generators supply electricity to national grids, and are dispatched in order of variable costs until demand is met. All generators are then paid a price for electricity that depends on the variable cost (basically fuel cost) of the marginal generation. For several years, this provided incentives to generation companies to incorporate new efficient generation equipment, with low operating cost. Thus, total installed capacity increased while wholesale electricity prices fell. In the process, many of the inefficient thermal power plants were eliminated from the system. By 1997, this process was so advanced that the price was set by marginal generators that were so efficient that their variable cost was relatively low. Those who had installed new efficient equipment saw returns on their investment drop to such values (about 20 Pesos per MWh, see Figure B.3.1 below) that they lost all incentive for further investment in power plants. Not that

at from 1992 to year end 2001, 1 Peso = 1 US Dollar, so that the wholesale electricity price fluctuated between 20 and 30 US\$ per MWh until the devaluation in early 2002. Shell realized a financial analysis of the proposed project in 2001, assuming an electricity sale price of 20 US\$ per MWh and an electricity purchase price of 30 US\$/MWh².

Since the devaluation in early 2002, and with about 4 Pesos to the US\$, the wholesale price of 30 Pesos per MWh was equivalent to about US\$ 7.5 per MWh, perhaps the lowest prices in the world (prices in Brazil and Chile are between US\$ 35 and 45 per MWh³), and far lower than a reasonable price to permit cost recovery of sunk investments, let alone add capacity. Even now, with 3 Pesos to the US\$ and a wholesale price spike of between 35 and 40 Pesos per MWh, this is still only about 12 or 13 US\$ per MWh.

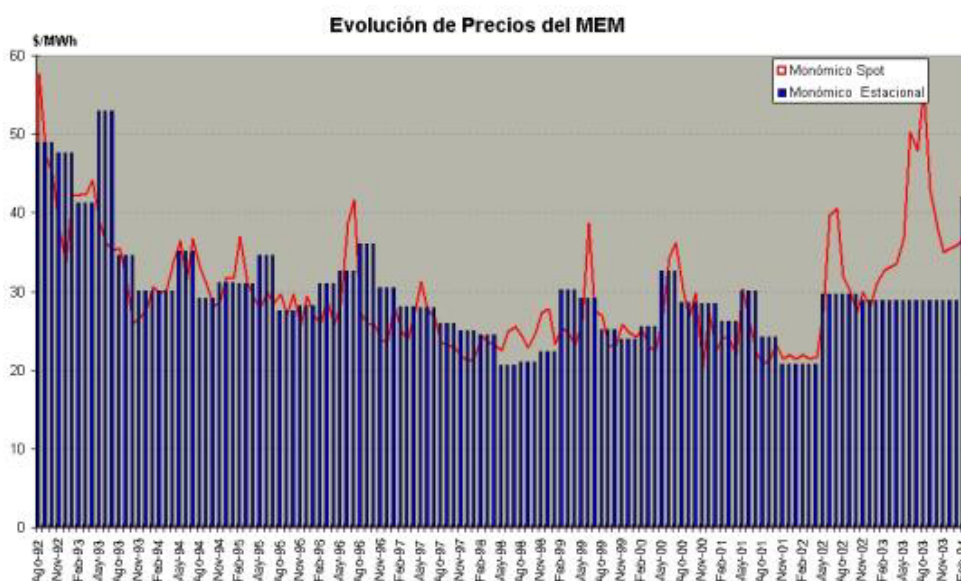


Figure B.3.1. Evolution in wholesale electricity prices in Argentina, 1992-2004. Values shown are in Pesos, which remained at a par with the US\$ up to year end 2001. In January 2002, the currency was devalued and exchange rate has varied between 2.7 Pesos and 4 Pesos per US\$ with a typical exchange rate being 3 pesos per US\$.

In summary, investing in electricity generation in Argentina has been an unprofitable venture since 1997, even for conventional generation technologies. The proposed project would turn the Shell CAPSA refinery into a net exporter of electricity which will be sold to the wholesale market at the prevailing, low prices. Thus the project presents a significant investment barrier.

Institutional barrier

Other rules of operation of the power market in Argentina also inhibit the installation of cogeneration. While, in Argentina cogenerators have open access to the transmission network, they face a significant cost penalty. Specifically, when the cogeneration system is not operational (and all equipment needs maintenance), the purchaser of cogenerated electricity needs to purchase electricity from the grid. A technical problem that requires shutting down the cogeneration system for even 15 minutes means not only that the power user pay for the electricity (kWh) consumed during this period, but also for the

² Shell, 2001. Group Budget Proposal for Shell CAPSA cogeneration project.

³ AGEERA (Asociación de Generadores de Energía Eléctrica de la República Argentina), 2002. *AGEERA Novedades*, No. 6, May.



maximum power demand (kW) *for the entire billing period*. Moreover, while the billing period is monthly, the billed peak demand remains at the maximum demand for six months at a time. Thus, if the cogeneration system is not operational even for a short period of time every year, the industrial user must pay the maximum demand charge all year long. Thus, the open market power system of Argentina, and other countries that underwent power sector reforms in the 1990s, favoured competition among power generators, but also implied a significant barrier to cogeneration.

It should be noted that cogeneration receives favourable treatment in those countries where significant amount of cogeneration has been developed. In some countries, e.g. Spain, cogeneration receives a dispatch advantage, whereby cogenerators meeting certain technical standards are at an advantage to export electricity to the grid. Other countries such as Germany subsidize cogeneration through favourable rates for cogenerated electricity. None of these advantages are available to cogeneration in Argentina.

Following the application of either Step 2 or Step 3 (or both), the Tool for demonstration and assessment of Additionality requires Steps 4 and 5, which are considered below.

Step 4 is Common Practice Analysis

Step 4 states:

"The above generic additionality tests shall be complemented with an analysis of the extent to which the proposed project type (e.g. technology or practice) has already diffused in the relevant sector and region. This test is a credibility check to complement the investment analysis (Step 2) or barrier analysis (Step 3)."

This step ensures that the stated barriers indeed have prevented similar projects from taking place. It is a credibility test on the validity of the barriers to project implementation. Step 4 comprises two Sub-Steps, which are discussed below.

Sub-step 4a. Analyse other activities similar to the proposed project:

1. Provide an analysis of any other activities implemented previously or currently underway that are similar to the proposed project activity. Projects are considered similar if they are in the same country and/or rely on a broadly similar technology, are of a similar scale, and take place in a comparable environment with respect to regulatory framework, investment climate, access to technology, access to financing, etc. Provide quantitative information where relevant.

Ever since deregulation of the power sector in Argentina in 1992, cogeneration has always faced significant barriers. As a result there are few such projects in the country. Three cogeneration projects are listed in the data base of the wholesale electricity management company (CAMMESA, Compañía Administradora del Mercado Mayorista Eléctrico S.A.). They are:

1. CMSENSEC CMS Ensenada.
2. SIDERCAC Siderca and
3. CTMENZAC C. T. Mendoza.

Here CMSENSEC and CTMENZAC are both cogeneration systems installed in refineries of Argentina's largest petroleum company, YPF. In both cases, the cogeneration system is owned by another company that provides heat and electricity to the refinery. Thus they operate in a "package cogeneration" mode, where the industry where the equipment is cited is not the owner of the cogeneration system. CMSENSEC is the oldest industrial cogeneration facility in Argentina and has been operating since Aug. 1997 (CAMMESA Annual Report, 1997). The other cogeneration facility CTMENZAC has been operating since the 1980s, prior to power sector deregulation and privatization.



SIDERCAC is a cogeneration plant owned by a steel mill. The parent company of the steel mill is the holding company TECHINT that owns steel mills at two cities in Buenos Aires province: San Nicolás and Campana. This cogeneration plant is physically located at the San Nicolás facility and “sells” electricity to the Campana steel mill, using the public transmission line. The cogeneration plant has been operating since Sept. 1997 (CAMMESA Annual Report, 1997).

Thus we note that the barriers operating against cogeneration since deregulation, and prior to the devaluation in early 2002, permitted only three cogeneration plants to be constructed during the period 1992-2001. After 2001, the *investment climate* in Argentina changed completely, as did key aspects of the *regulatory framework* for the power sector, and no further cogeneration projects were realized, except for the project in question.

Sub-step 4b: “Discuss any similar options that are occurring” does not apply since no similar activities are widely observed nor commonly carried out.

The final step for demonstrating additionality is Step 5. Impact of CDM Registration

The consolidated tools states:

“Explain how the approval and registration of the project as a CDM activity, and the attendant benefits and incentives derived from the project activity, will alleviate the economic and financial hurdles (Step 2) or other identified barriers (Step 3) and thus enable the project to be undertaken.”

The tool provides a list of potential benefits and incentives. The adaptation of the tool in the baseline methodology suggests that the following three items are especially relevant:

- Anthropogenic greenhouse gas emission reductions;
- The financial benefit of the revenue obtained by selling CERs;
- Improved environmental image of the project proponent.

Clearly, the project would benefit from the first two items. The third item is also relevant.

Earlier in the section, we have already commented that Shell, as one of the largest energy companies, is acutely aware of climate change, and includes GHG emissions in all its investment decisions. Approval and registration of this project as a CDM activity would therefore be of great significance to Shell, showing that its activities are helping to mitigate climate change. CDM registration will provide independent confirmation of Shell’s corporate responsibilities in the climate change area.

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

>>

The project boundary is the boiler room / power station (BRPS) located within the refinery. Petroleum fuels from the refinery itself plus natural gas from the gas pipeline outside the refinery supply fuel to the boiler room /power station. Electricity and steam are generated in the BRPS. Electricity is supplied from the BRPS to the rest of the refinery. When generated electricity is insufficient to meet demand (such as in the baseline case), additional electricity is purchased from an electricity distribution company through the power grid. When BRPS electricity generation exceeds refinery demand (as is expected in the project scenario), excess electricity would be sold to the wholesale power market through the power grid.

This choice of project boundary makes sense for various reasons:



- The project involves changes in the equipment within the BRPS, and not in the rest of the factory.
- The boiler room / power station (BRPS) is denominated “Usina” in the refinery and is a separate operational unit. This unit maintains strict records of fuel input to the BRPS, steam and electricity output from the BRPS to the refinery, as well as any electricity bought or sold through the public grid.

See baseline methodology for choices of project boundary.

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

>>

Detailed baseline information is provided in Annex 3 to this PDD.

Date of completion of the baseline study: May 31, 2005.

Baseline study prepared by

Dr. Gautam Dutt and Ing. Nuria Zanzottera, MGM International, Ltda. (not a project participant).

Tel: +54-11-5219-1230

e-mail: gdutt@mgminter.com; nzanzottera@mgminter.com;

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:

>>

September 2003.

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

>>

25 years

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

C.2.1. Renewable crediting period

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

>>

January 1, 2004.

C.2.1.2. Length of the first crediting period:

>>

7 years.

**C.2.2. Fixed crediting period:**

NOT SELECTED.

C.2.2.1. Starting date:

>>

C.2.2.2. Length:

>>

SECTION D. Application of a monitoring methodology and plan**D.1. Name and reference of approved monitoring methodology applied to the project activity:**

>>

Cogeneration at an industrial facility.

This new methodology incorporates ACM0002 “Consolidated monitoring methodology for grid-connected electricity generation from renewable sources.” An alternative methodology for power generation from renewable energy sources, applicable to power output below 15 MW, is the small-scale methodology I. D “Renewable electricity generation for a grid.” The methodology also incorporates equations from another approved methodology: AM0008 “Industrial fuel switching from coal and petroleum fuels to natural gas without extension of capacity and lifetime of the facility.”

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

>>

The methodology was selected in order to be applicable to projects such as that proposed here.

PROJECT DESIGN DOCUMENT FORM (CDM PDD) - Version 02

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 number (Please use numbers to ease cross-referencing to D.3)	Data variable	Source of data	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)	Comment
P.1 $AFC_{a,i}$	Annual fuel consumption (AFC) for asphalt (a) in boiler i	Refinery	tonne SRF	m	month	100%	Paper (field) and electronic	SRF: standard refinery fuel, an equivalent energy unit. Subscript 'a' refers to fuel asphalt. 'i' refers to boiler or other equipment using fuel.
P.2. $AFC_{fg,i}$	AFC for fuel gas in boiler i	Refinery	tonne SRF	m	month	100%	Paper (field) and electronic	Subscript 'fg' refers to fuel gas, which is mostly refinery gas blended with natural gas.
P.3. $AFC_{fo,i}$	AFC for fuel oil in boiler i	Refinery	tonne SRF	m	month	100%	Paper (field) and electronic	Subscript 'fo' refers to fuel oil.
P.4. AFC_{ng}	AFC for natural gas in heat recovery boiler	Refinery	tonne SRF	m	month	100%	Paper (field) and electronic	Subscript 'ng' refers to natural gas.

D.2.1.2. Description of formulae used to estimate project emissions (for each gas, source, formulae/algorithm, emissions units of CO₂ equ.)

>>

The project activity involves the installation of a gas turbine. The project activity would increase electricity generation at the facility with excess electricity sold to the interconnected power grid. Since the gas turbine operates on natural gas, the project also involves increased use of this fuel and decreased use of petroleum fuels. Both of these components would reduce GHG emissions compared to the baseline.

This template shall not be altered. It shall be completed without modifying/adding headings or logo, format or font.

PROJECT DESIGN DOCUMENT FORM (CDM PDD) - Version 02

The project emissions E (expressed in tonnes of CO₂ equivalent per year, tCO₂e/yr) are given by:

$$E = \sum_i FC_i \cdot (EF_i + MEF_i \cdot GWP(CH_4) + NEF_i \cdot GWP(N_2O)) \quad \text{Eq. (D.1)}$$

where:

FC_i	consumption of fuel i used in the project scenario, measured in energy units (e.g. gigajoule, GJ)
EF_i	carbon dioxide emission factor per unit energy of fuel i (e.g. tCO ₂ e/GJ) (combustion)
MEF_i	methane emission factor per unit energy of fuel i (e.g. tCH ₄ /GJ) (combustion)
$GWP(CH_4)$	global warming potential of CH ₄ set as 21 tCO ₂ e/tCH ₄ for the 1 st commitment period
NEF_i	nitrous oxide emission factor per unit energy of fuel i (e.g. tN ₂ O/GJ) (combustion)
$GWP(N_2O)$	global warming potential of N ₂ O set as 310 tCO ₂ e/tN ₂ O for the 1 st commitment period

D.2.1.3. Relevant data necessary for determining the <u>baseline</u> of anthropogenic emissions by sources of GHGs within the project boundary and how such data will be collected and archived :								
ID number (Please use numbers to ease cross-referencing to table D.3)	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e),	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/paper)	Comment
B.1. $SFC_{a,i}$	specific fuel consumption asphalt in equip. i	Refinery	tonne SRF /100 t HPS	m	month	100%	Paper (field) and electronic	HPS: high pressure steam.
B.2. $SFC_{fg,i}$	SFC for fuel gas, equip i	Refinery	tonne SRF /100 t HPS	m	month	100%	Paper (field) and electronic	
B.3. $SFC_{fo,i}$	SFC for fuel oil, equip i	Refinery	tonne SRF /100 t HPS	m	month	100%	Paper (field) and electronic	
B.4. SFC_{ng}	SFC for natural gas in heat recovery	Refinery	tonne SRF /100 t HPS	m	month	100%	Paper (field) and electronic	

This template shall not be altered. It shall be completed without modifying/adding headings or logo, format or font.

PROJECT DESIGN DOCUMENT FORM (CDM PDD) - Version 02

	<i>boiler</i>							
<i>B.5. NPES</i>	<i>Net electricity sales to grid in project scenario</i>	<i>Refinery / power co.</i>	<i>MWh</i>	<i>m</i>	<i>month</i>	<i>100%</i>	<i>Paper (field) and electronic</i>	<i>Following project implementation, there will be a surplus generating capacity in the refinery so that there electricity purchases in the project scenario will be limited to brief intervals and small amounts.</i>
<i>B.6. NBEP</i>	<i>Net electricity purchases from grid in baseline scenario</i>	<i>Refinery / power co.</i>	<i>MWh</i>	<i>m</i>	<i>month</i>	<i>100%</i>	<i>Paper (field) and electronic</i>	<i>No electricity was sold to grid prior to project implementation. Thus NBEP = BEP.</i>
<i>B.7. EF_{OM}</i>	<i>CO₂ operating margin emission factor for grid</i>		<i>t CO₂/MWh</i>	<i>c</i>	<i>year</i>	<i>100%</i>	<i>electronic</i>	<i>Determine Simple operating margin, as defined in ACM0002 and interpreted in Annex 3 of this PDD. Calculate updated value for each year.</i>
<i>B.8. EF_{BM}</i>	<i>CO₂ build margin emission factor for grid</i>		<i>t CO₂/MWh</i>	<i>c</i>	<i>year</i>	<i>100%</i>	<i>electronic</i>	<i>Determine build margin, as defined in ACM0002 and interpreted in Annex 3 of this PDD. Calculate updated value for each year.</i>
<i>B.9 EF_{elec gen}</i>	<i>CO₂ combined margin emission factor for grid</i>		<i>t CO₂/MWh</i>	<i>c</i>	<i>year</i>	<i>100%</i>	<i>electronic</i>	<i>Determined as average of EF_{OM} and EF_{BM}-. Update annually.</i>
<i>B.10. F_{i,y}</i>	<i>Amount of each fossil fuel consumed by each power source / plant</i>	<i>CAMMESA - Compañía Administradora del Mercado Mayorista Eléctrico SA</i>	<i>Mass or volume</i>	<i>m</i>	<i>yearly</i>	<i>100%</i>	<i>electronic</i>	
<i>B.11. COEF_i</i>	<i>CO₂ emission coefficient of each fuel type i</i>	<i>IPCC default values.</i>	<i>tCO₂/mass or volume unit</i>	<i>m</i>	<i>yearly</i>	<i>100%</i>	<i>electronic</i>	<i>When plant or country specific values to calculate COEF are not available, IPCC default values are used.</i>

PROJECT DESIGN DOCUMENT FORM (CDM PDD) - Version 02

B.12. $GEN_{j/k/n,y}$	Electricity generation of each power source / plant j, k or n	CAMMESA - Compañía Administradora del Mercado Mayorista Eléctrico SA	MWh/year	m	yearly	100%	electronic	
B.13.	Identification of power source / plant for the OM	CAMMESA - Compañía Administradora del Mercado Mayorista Eléctrico SA	Text	e	yearly	100% of set of plants	electronic	
B.14.	Identification of power source / plant for the BM	CAMMESA - Compañía Administradora del Mercado Mayorista Eléctrico SA	Text	e	yearly	100% of set of plants	electronic	
For dynamic baseline emission determination the following data will also be needed:								
B.15. EG	Baseline electricity generation in the BRPS	Calculated in dynamic baseline procedure	MWh	c	yearly	100%	electronic	
B.16 H	Baseline total heat output of the BRPS (refinery steam demand)	Calculated from monitored values of steam output following <i>project</i> implementation.	GJ measured as total steam enthalpy.	c	yearly	100%	electronic	Total enthalpy in dynamic baseline is equal to total enthalpy in project.
B.17 σ_{elect}	Baseline (historical) BRPS specific electricity generation	Calculated from average power output and average steam output, using data on for 3 years prior to project implementation	MWh / GJ of steam enthalpy	c	once	once	Paper, electronic	Factor calculated once from historical data

PROJECT DESIGN DOCUMENT FORM (CDM PDD) - Version 02

<i>B.18 EP</i>	Baseline electricity purchase from the grid	Calculated in dynamic baseline procedure	MWh	<i>c</i>	yearly	100%	<i>electronic</i>	
<i>B.19 ED</i>	Electricity demand of the refinery	Monitored following project implementation	MWh	<i>m</i>	yearly	100%	<i>electronic</i>	Electricity demand in dynamic baseline is equal to project electricity demand
<i>B.20 FC_{total}</i>	total fuel consumption in the BRPS	Calculated in dynamic baseline procedure	ton SRF	<i>c</i>	yearly	100%	<i>electronic</i>	
<i>B.21 λ_{FC}</i>	Baseline (historical) BRPS specific fuel consumption for steam generation	Calculated from average fuel consumption and average steam output, using data for 3 years prior to project implementation	ton SRF / GJ of total steam enthalpy	<i>c</i>	once	once	<i>Paper, electronic</i>	Factor calculated once from historical data
<i>B.22 FC_{asphalt}</i>	Baseline asphalt consumption in the BRPS	Calculated in dynamic baseline procedure	ton SRF	<i>c</i>	yearly	100%	<i>electronic</i>	
<i>B.23 FC_{fuel_gas}</i>	Baseline fuel gas consumption in the BRPS	Calculated in dynamic baseline procedure	ton SRF	<i>c</i>	yearly	100%	<i>electronic</i>	
<i>B.24 FC_{fueloil}</i>	Baseline fuel oil consumption in the BRPS	Calculated in dynamic baseline procedure	ton SRF	<i>c</i>	yearly	100%	<i>electronic</i>	
<i>B.25 f_{asphalt}</i>	Baseline (historical) proportion of asphalt used in the fuel mix	Calculated from consumption data of each fuel for 3 years prior to project implementation	-	<i>c</i>	once	once	<i>Paper, electronic</i>	Factor calculated once from historical data

PROJECT DESIGN DOCUMENT FORM (CDM PDD) - Version 02

$B.26$ $f_{fuel\ gas}$	Baseline (historical) proportion of asphalt used in the fuel mix	Calculated from consumption data of each fuel for 3 years prior to project implementation	-	c	once	once	<i>Paper, electronic</i>	Factor calculated once from historical data
$B.27$ $f_{fuel\ oil}$	Baseline (historical) proportion of asphalt used in the fuel mix	Calculated from consumption data of each fuel for 3 years prior to project implementation	-	c	once	once	<i>Paper, electronic</i>	Factor calculated once from historical data

D.2.1.4. Description of formulae used to estimate baseline emissions (for each gas, source, formulae/algorithm, emissions units of CO₂ equ.)

>>

Baseline emissions BE (expressed in tonne CO₂equivalent per year, tonne CO₂e/yr) are given by:

$$BE = \sum_i BFC_i (EF_i + MEF_i \cdot GWP(CH_4) + NEF_i \cdot GWP(N_2O)) + (NBEP + NPES) \cdot EF_{elec\ gen} \quad \text{Eq. (D.2)}$$

where

BFC_i	consumption of fuel i used in the baseline scenario, measured in energy units (e.g. gigajoule, GJ)
EF_i	carbon dioxide emission factor per unit energy of fuel i (e.g. tCO ₂ /GJ) (combustion)
MEF_i	methane emission factor per unit energy of fuel i (e.g. tCH ₄ / GJ) (combustion)
$GWP(CH_4)$	global warming potential of CH ₄ set as 21 tCO ₂ e/tCH ₄ for the 1 st commitment period
NEF_i	nitrous oxide emission factor per unit of energy of fuel i (e.g. tN ₂ O/ GJ) (combustion)
$GWP(N_2O)$	global warming potential of N ₂ O set as 310 tCO ₂ e/tN ₂ O for the 1 st commitment period
$NBEP$	net electricity purchased (electricity purchased less electricity sold) through the grid in the baseline (e.g. MWh)
$NPES$	net electricity sold (electricity sold less electricity purchased) through the grid in the project scenario (e.g. MWh)
$EF_{elec\ gen}$	baseline “combined margin” emission factor for grid electricity generation (e.g. kg CO ₂ e/MWh)

PROJECT DESIGN DOCUMENT FORM (CDM PDD) - Version 02

Baseline emissions correspond to the emissions from fuels burnt at the refinery in the baseline scenario. Electricity purchased through the power grid to meet a part or all of the demand at the refinery would cause emissions elsewhere in the power grid. Such emissions are included in the baseline emissions. Following project implementation, electricity is expected to be sold from the refinery through the power grid, so that emissions would be offset elsewhere in the grid. In the absence of such electricity supply in the baseline scenario, there would be additional emissions in electricity generation, which are also included in baseline emissions.

Note that we consider *net* electricity purchase from the grid in the baseline scenario and *net* electricity sold through the grid in the project scenario, as explained in the definitions of *NBEP* and *NPES*. This equation allows for one or other of these quantities to be negative. To avoid confusion these emissions are included in the baseline emissions equation only. In the proposed project, both terms are expected to be positive.

The emissions associated with electric power generation depend on the sum $NBEP + NPES$ and $EF_{elec\ gen}$, the emissions factor for electricity generation in the connected power grid. It is the product of these two quantities: $(NBEP + NPES) \cdot EF_{elec\ gen}$.

The methodology applicable here uses the approved consolidated monitoring methodology ACM0002 “Consolidated monitoring methodology for zero-emissions grid-connected electricity generation from renewable sources” for determining $EF_{elec\ gen}$. ACM0002 offers some alternative pathways for determining $EF_{elec\ gen}$. For this project, the data available permit the use of the Simple Operating Margin and the Build Margin based on the most recent power plants built accounting for 20% of the total generation. Details of the procedure, data and results are shown in Annex 3.

The methodology recommends the use of thermodynamic analysis for *ex-ante* estimates of baseline and project emissions to be reported in the PDD.

The methodology requires *ex post* baseline emissions to be determined in a dynamical manner from project monitoring data using the total enthalpy of steam output going to meet industrial heat demand. The heat demand of the refinery is given by the heat production of the BRPS minus BRPS internal consumption. If industrial output increases or decreases, so will this heat demand, so that both baseline and project emissions would be adjusted by industrial output.

As specified in the baseline methodology, *ex-post* baseline emissions will be determined in a dynamic manner from project monitoring data through the following steps:

1. From historical data, determine the relationship between (a) fuel input and total steam enthalpy output and (b) total electric power output and total steam enthalpy output.
2. If more than one fuel type is used prior to project implementation, determine average ratio of fuel input of different fuels, again from historical data.
3. Following project implementation, determine total enthalpy value of steam produced by the cogeneration system from monitored data.
4. Using the historic relationship (step 1 above), determine (a) baseline fuel consumption and (b) electric power output corresponding to the measured data on steam output following project implementation. When more than one fuel is used prior to project implementation, determine consumption of each fuel using historical ratios of the different components (step 2 above). These are the values of BFC_i .

This template shall not be altered. It shall be completed without modifying/adding headings or logo, format or font.

PROJECT DESIGN DOCUMENT FORM (CDM PDD) - Version 02

5. From the step 4 estimate of electric power output and monitored power demand of industry, determine net purchase of electricity from the grid in baseline, *NBEP*.
6. From monitored data of electricity sold through the interconnected grid following project implementation, determine electricity sale through the grid, *NPES*.
7. Use Eq. (D.2) to calculate baseline emissions using BFC_i from Step 4, *NBEP* from Step 5, and *NPES* from Step 6.

Steps 1 and 2 may be determined from historical data.

Step 1(a)

From historical data we determine the ratio between total fuel consumption and the heat output of the BRPS:

$$FC_{total} = \lambda_{FC} \bullet H \quad \text{Eq. (D.3)}$$

FC_{total} is total fuel consumption in the BRPS, ton SRF

λ_{FC} is the BRPS specific fuel consumption for steam generation, ton SRF / GJ of total steam enthalpy,

H is the heat output of the BRPS (equal to refinery steam demand), GJ total steam enthalpy.

By considering average values of FC_{total} and S , we determine λ_{FC} .

Step 1(b)

Again from historical data, we determine the ratio between electricity generation and net heat output (steam production) from the BRPS to the refinery:

$$EG = \sigma_{elect} \bullet H \quad \text{Eq. (D.4)}$$

where

EG is the electricity generation in the BRPS, MWh

σ_{elect} is the BRPS specific electricity generation, MWh / GJ of steam enthalpy ,

H is the total heat output of the BRPS (equal to refinery steam demand), GJ measured as total steam enthalpy.

Step (2)

This template shall not be altered. It shall be completed without modifying/adding headings or logo, format or font.

PROJECT DESIGN DOCUMENT FORM (CDM PDD) - Version 02

From monitored total steam enthalpy demand of the refinery, one can determine equivalent total fuel consumption in the baseline using the Here fuel consumption is determined as a total and expressed in SRF (standard refinery fuel) units. The BRPS uses a combination of fuels available at the refinery to produce steam and electricity. The consumption of each fuel is calculated from the total fuel consumption, FC_{total} , using the historical proportion of each fuel in the fuel mix. We use data for three years prior to project implementation in order to calculate the proportion of different fuels in the fuel mix.

The proportion f of each fuel is given by the following formulae:

$$f_{asphalt} = \frac{FC_{asphalt}}{FC_{asphalt} + FC_{fuel_gas} + FC_{fueloil}} \quad \text{Eq. (D.5)}$$

$$f_{fuel_gas} = \frac{FC_{fuel_gas}}{FC_{asphalt} + FC_{fuel_gas} + FC_{fueloil}} \quad \text{Eq. (D.6)}$$

$$f_{fuel_oil} = \frac{FC_{fuel_oil}}{FC_{asphalt} + FC_{fuel_gas} + FC_{fueloil}} \quad \text{Eq. (D.7)}$$

where the fuel consumption values FC correspond to average values from the previous three years of data.

The dynamic baseline calculation will assume that the f values as determined using the above formulae remain unchanged.

The consumption of each fuel in the dynamic baseline would be determined by these f values and the FC_{total} value determined by Eq. (D.3) above:

$$BFC_{asphalt} = FC_{total} \cdot f_{asphalt} \quad ; \quad BFC_{fuel_gas} = FC_{total} \cdot f_{fuel_gas} \quad ; \quad BFC_{fuel_oil} = FC_{total} \cdot f_{fuel_oil} \quad \text{Eq. (D.8)}$$

Step 3.

This template shall not be altered. It shall be completed without modifying/adding headings or logo, format or font.

PROJECT DESIGN DOCUMENT FORM (CDM PDD) - Version 02

Following project implementation, monitored data on total steam output from boiler room / power station sent to the refinery is used to determine total steam enthalpy using the following formula:

$$H = (Q_M \times h_M + Q_L \times h_L) / 1000 \quad \text{Eq. (D.9)}$$

where

H	= total steam enthalpy, GJ
Q_M	= mass of medium pressure steam, tonnes per year
Q_L	= mass of low pressure steam, tonnes per year
h_M	= specific enthalpy of medium pressure steam, MJ/tonne
h_L	= specific enthalpy of low pressure steam, MJ/tonne

Step 4(a)

Total fuel consumption, FC_{total} corresponding to the value of H calculated in Step 3 is determined using Eq. (D.3).

The consumption of each fuel FC_i , where i can be fuel oil, asphalt, or fuel gas is next determined using Eq. (D.8) using the coefficients f determined in Eqs. (D.5, D.6 and D.7). These are the values of BFC we need to use in Eq. (D.2) in order to determine baseline emissions.

Step 4(b)

Total electric power generation in the baseline scenario, corresponding to the value of H calculated in Step 3, is determined using Eq. (D.4).

Step 5

Then, the electricity that would be purchased from the power grid (in the baseline configuration) is calculated by subtracting the electricity generation calculated in Step 4(b) from the *monitored* value of total refinery demand of electricity:

$$EP = ED - EG$$

EP is the electricity purchase from the grid needed in the baseline configuration, MWh per year

This template shall not be altered. It shall be completed without modifying/adding headings or logo, format or font.

PROJECT DESIGN DOCUMENT FORM (CDM PDD) - Version 02

ED is electricity demand of the refinery, monitored from project data, MWh per year

EG is the electricity output of the BRPS in the baseline configuration, MWh per year

This value of EP is in fact the *NBEP* we need to use in Eq. (D.2) in order to determine baseline emissions.

Step 6

The monitored data of electricity sold through the interconnected grid following project implementation, directly yields *NPES*, another quantity we need to use in Eq. (D.2) in order to determine baseline emissions.

Step 7

All that remains now is to calculate dynamic baseline emissions using Eq. (D.2) and values of *BFC_i* obtained in Step 4, *NBEP* obtained in Step 5, and *NPES* obtained in Step 6.

D. 2.2. Option 2: Direct monitoring of emission reductions from the project activity (values should be consistent with those in section E).

OPTION NOT USED

D.2.2.1. Data to be collected in order to monitor emissions from the <u>project activity</u>, and how this data will be archived:								
ID number (Please use numbers to ease cross-referencing to table D.3)	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e),	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

NOT APPLICABLE (OPTION 2.2 NOT USED)

This template shall not be altered. It shall be completed without modifying/adding headings or logo, format or font.

PROJECT DESIGN DOCUMENT FORM (CDM PDD) - Version 02

D.2.2.2. Description of formulae used to calculate project emissions (for each gas, source, formulae/algorithm, emissions units of CO₂ equ.):

>>

NOT APPLICABLE (OPTION 2.2 NOT USED)

D.2.3. Treatment of leakage in the monitoring plan

D.2.3.1. If applicable, please describe the data and information that will be collected in order to monitor leakage effects of the project activity

ID number (Please use numbers to ease cross-referencing to table D.3)	Data variable	Source of data	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)	Comment

Fugitive CH₄ emissions from fuel production and transport, and CO₂ emissions from fuel transportation are categorized as leakage. The fuels used in the project are produced within the refinery, with the exception of natural gas. Thus only methane emissions from natural gas production and gas pipelines are relevant here.

Since emissions associated with leakage are very small compared with project and baseline emissions, they are estimated from IPCC default values, without any requirement for monitoring.

D.2.3.2. Description of formulae used to estimate leakage (for each gas, source, formulae/algorithm, emissions units of CO₂ equ.)

>>

The leakage LE_y is expressed as

$$LE = (FC_i - BFC_i) \bullet FE_i(CH_4) \bullet GWP(CH_4) + \sum_j TF_j \bullet EF_j - \sum_k BTF_k \bullet EF_k$$

where $FE_i(CH_4)$ is the IPCC default methane emission factor of fuel i associated with fugitive emissions. In this case, only natural gas is relevant. Fugitive methane emissions are associated with natural gas production and pipeline leakage, and are included here.

This template shall not be altered. It shall be completed without modifying/adding headings or logo, format or font.

PROJECT DESIGN DOCUMENT FORM (CDM PDD) - Version 02

The second line in the above formula refers to emissions from fuel transportation, which can be ignored for this project, since the fuels are produced on site.

D.2.4. Description of formulae used to estimate emission reductions for the project activity (for each gas, source, formulae/algorithm, emissions units of CO₂ equ.)

>>

The emission reductions *ER* by the project activity are given by:

$$ER = BE - E - LE \quad \text{expressed in tonnes of CO}_2 \text{ equivalent (tCO}_2\text{e/yr).}$$

Where

BE are baseline emissions determined in a dynamic manner as explained in section D.2.1.4,

E are project emissions determined as indicated in section D.2.1.2, and

LE are leakage emissions estimated as indicated in section D.2.3.2.

Note that an important component of determining emissions reductions depends on baseline emissions associated with electric power generation connected to the grid. These are described in Annex 3.

D.3. Quality control (QC) and quality assurance (QA) procedures are being undertaken for data monitored		
Data (Indicate table and ID number e.g. 3.-1.; 3.2.)	Uncertainty level of data (High/Medium/Low)	Explain QA/QC procedures planned for these data, or why such procedures are not necessary.
<i>Table D.2.1.1, P.1</i>	<i>Low</i>	<i>Procedures include calibration of instruments used to measure fuel consumption</i>
<i>P.2</i>	<i>Low</i>	<i>Procedures include calibration of instruments used to measure fuel consumption</i>
<i>P.3</i>	<i>Low</i>	<i>Procedures include calibration of instruments used to measure fuel consumption</i>
<i>P.4</i>	<i>Low</i>	<i>Procedures include calibration of instruments used to measure fuel consumption</i>
<i>Table D.2.1.3, B.1</i>	<i>Low</i>	<i>Procedures include calibration of instruments used to measure heat output(as well as fuel consumption)</i>
<i>B.2</i>	<i>Low</i>	<i>Procedures include calibration of instruments used to measure heat output(as well as fuel consumption)</i>
<i>B.3</i>	<i>Low</i>	<i>Procedures include calibration of instruments used to measure heat output(as well as fuel consumption)</i>
<i>B.4</i>	<i>Low</i>	<i>Procedures include calibration of instruments used to measure heat output(as well as fuel consumption)</i>
<i>B.5</i>	<i>Low</i>	<i>Procedures for calibration of electricity meters</i>
<i>B.6</i>	<i>Low</i>	<i>Procedures for calibration of electricity meters</i>
<i>B.7</i>	<i>Low</i>	<i>Determined from published data obtained from national load dispatch centre CAMMESA.</i>
<i>B.8</i>	<i>Low</i>	<i>Determined from published data obtained from national load dispatch centre CAMMESA</i>

This template shall not be altered. It shall be completed without modifying/adding headings or logo, format or font.

PROJECT DESIGN DOCUMENT FORM (CDM PDD) - Version 02

B.9	Low	Simple calculation.
B.10	Low	Determined from published data obtained from national load dispatch centre CAMMESA
B.11	Low	Determined from IPCC
B.12	Low	Determined from published data obtained from national load dispatch centre CAMMESA
B.13	Low	Determined from published data obtained from national load dispatch centre CAMMESA
B.14	Low	Determined from published data obtained from national load dispatch centre CAMMESA

D.4 Please describe the operational and management structure that the project operator will implement in order to monitor emission reductions and any leakage effects, generated by the project activity

>>

Shell CAPSA already maintains excellent records of the data required for monitoring purposes. Thus no changes in operational and management structure will be required. The monitoring plan incorporates a procedure for utilising the monitored data and determining project emissions, estimating (dynamic) baseline emissions and emissions reductions. Record keeping will include calibration of measuring equipment, including flow and other meters for fuel consumption measurement, steam flow and quality measurements, as well as electricity output to the refinery and sold through the power grid.

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

>>

Dr. Gautam Dutt and Ing. Nuria Zanzottera, MGM International, Ltda. (not a project participant). Tel: +54-11-5219-1230
e-mail: gdutt@mgminter.com; nzanzottera@mgminter.com;

**SECTION E. Estimation of GHG emissions by sources****E.1. Estimate of GHG emissions by sources:**

>>

Figure E1 shows the baseline situation for heat and electricity supply to the refinery, including the purchase of extra electricity from the grid, while Figure E2 shows the situation after project implementation, involving the installation of a gas turbine system and the sale of surplus electricity through the grid. The project boundary is shown by the dashed line in Figures E1 and E2. Note that the gas turbine installed together with some of the previously existing equipment can provide all of the refinery's demand for electricity and the heat with surplus of electricity to be sold through the grid. Note further that the heat recovery steam generator (HSRG) that uses exhaust heat from the gas turbine to produce steam includes a supplementary boiler for co-firing, using natural gas. While this is included in the figure here, it is not expected to be used.

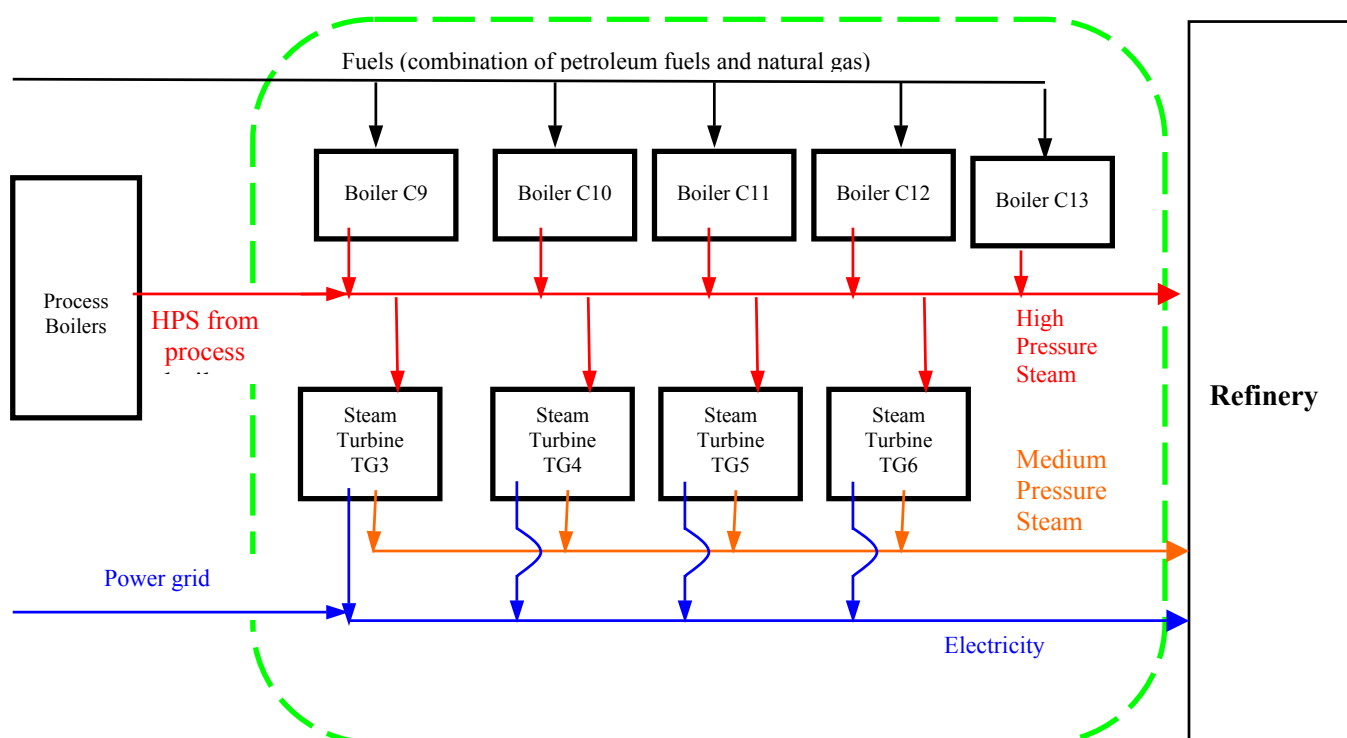


Figure E.1. System boundary and equipment in the baseline situation.

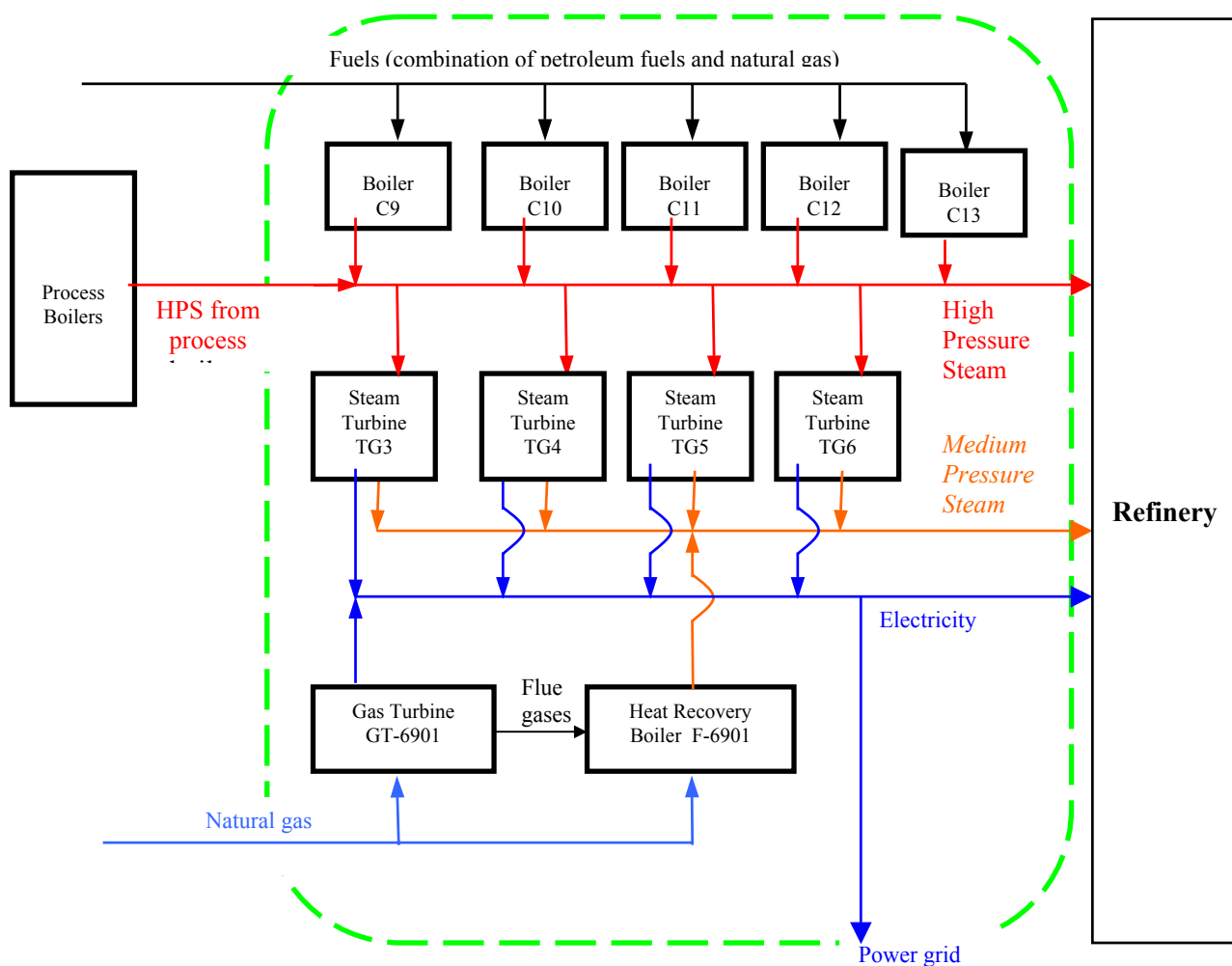


Figure E.2. System boundary and equipment in the project situation.

Fuel combustion in boilers are responsible for GHG emissions within the project boundary in the baseline situation (see Figure E.3). Additional emissions are associated with electricity purchased from the grid.

In the project situation, fuel combustion in the gas turbine and in remaining boilers produce GHG emissions within the project boundary (see Figure E.4). However, since the system now produces excess electricity which is sold through the power grid, this electricity generation offsets emissions from power plants elsewhere in the power grid.

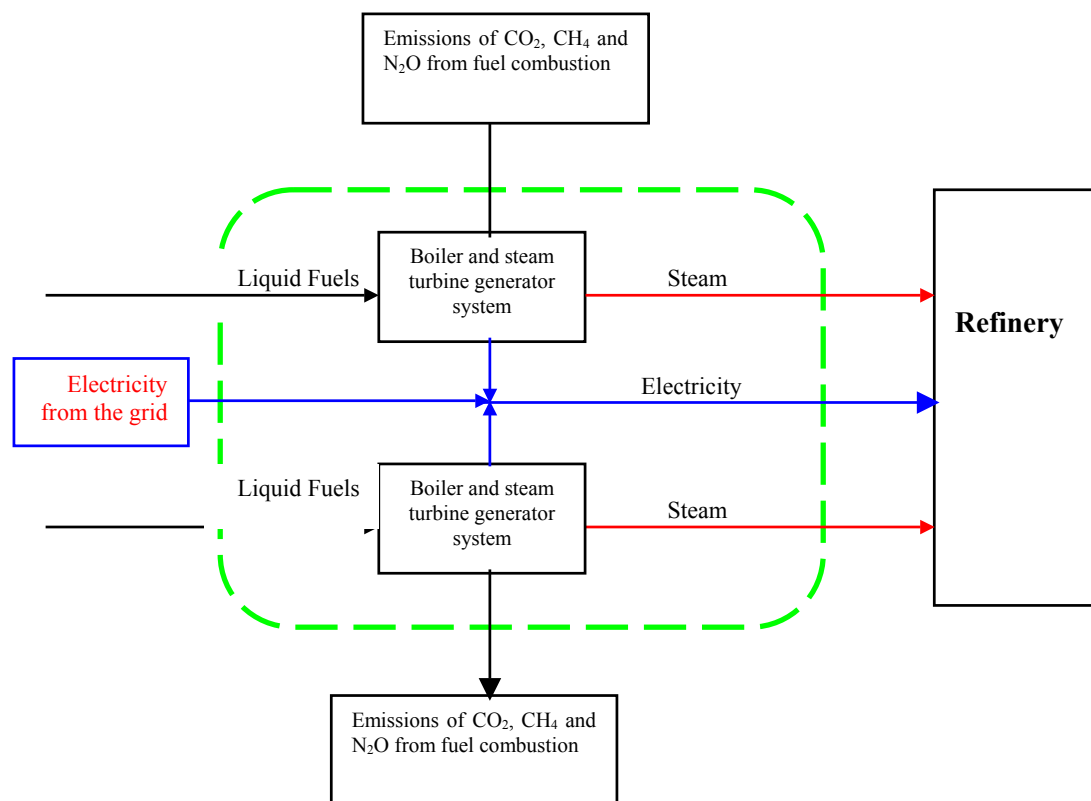


Figure E.3. GHG emissions from fuel combustion within the project boundary in the *baseline* situation. Additional emissions associated with electricity purchased through the grid are not shown.

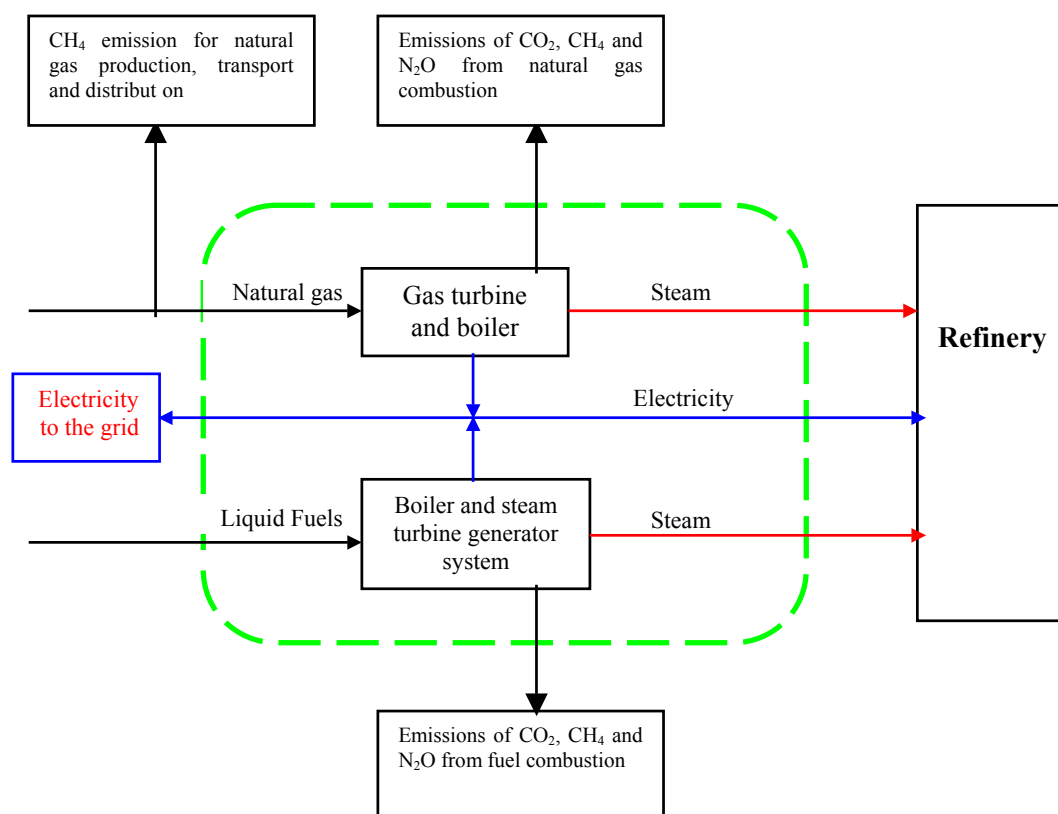


Figure E.4. GHG emissions from fuel combustion within the project boundary in the *project* situation. Emissions offset elsewhere in the power grid as a result of electricity supplied by the system to the grid are not shown.

In both the baseline and the project situations, GHG emissions within the project boundary correspond to fuels burnt within the boiler room / power station (BRPS). Each of these emissions may be expressed as the product of an emissions factor and fuel energy consumption by equipment within the BRPS.

Each fuel energy consumption is determined from monitored fuel consumption as follows:

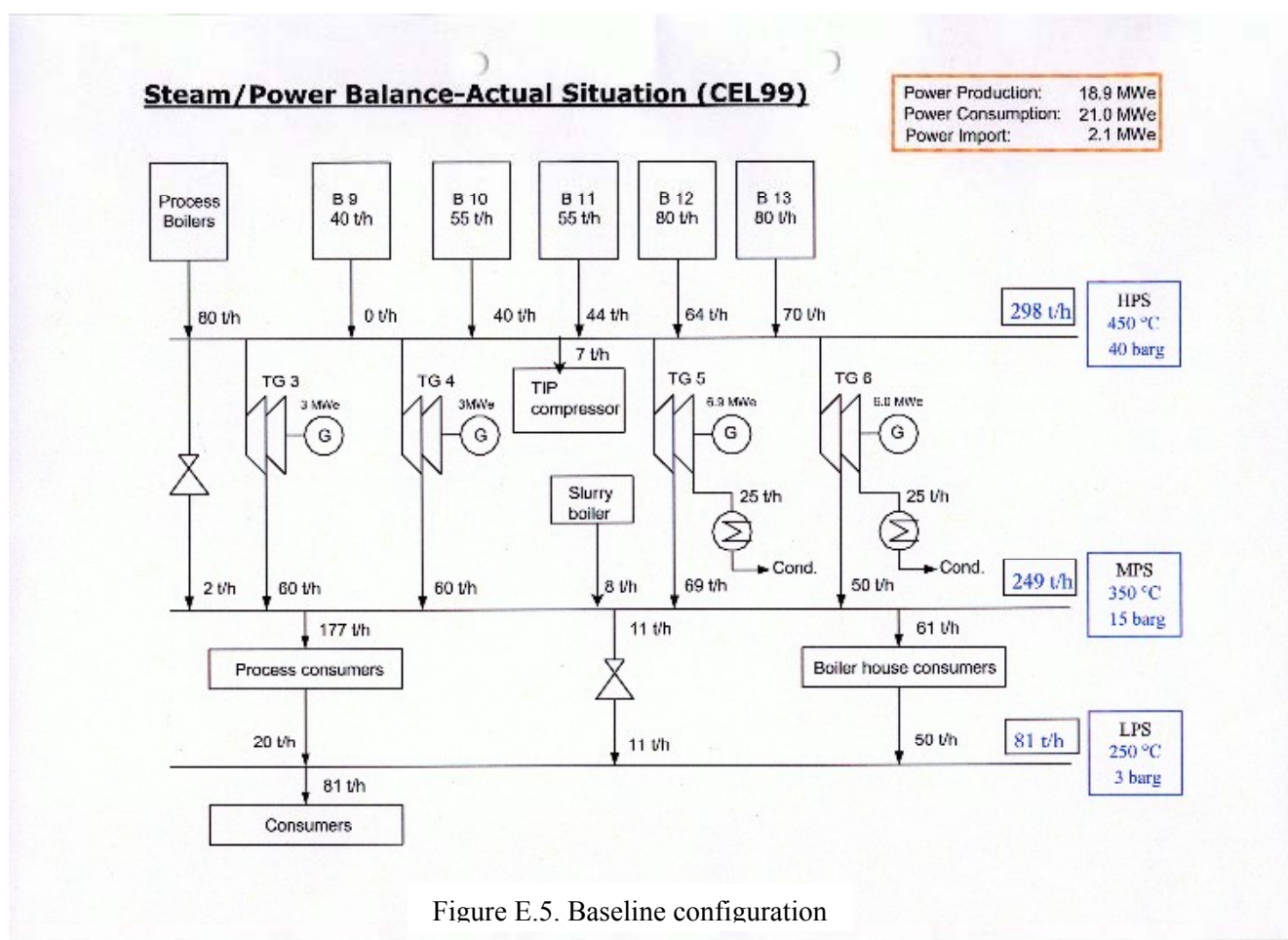


Annual energy consumption for each fuel within the project boundary, FC_{fuel} (GJ/year), is given by:

$$FC_{fuel} \text{ (GJ/year)} = \frac{MFC_{fuel} \cdot CV_{fuel} \cdot 4.1868 \text{ J/cal}}{10^3} \quad (\text{Eq. E.1})$$

where MFC_{fuel} = mass fuel consumption of each fuel (ton/yr)
 CV_{fuel} = lower heating value of each fuel (kcal/kg), and
 $Fuel$ = asphalt, fuel gas, fuel oil, or natural gas

Ex ante baseline and project emissions are estimated from a thermodynamic analysis of the system. The steam and power flows of the baseline and project configurations are shown in Figs. E.5 and E.6. Note that the boiler room / power station (BRPS) produces steam at three conditions: high-pressure steam (HPS, 450 °C and 40 bar gauge), medium-pressure steam (MPS, 350 °C, 15 bar g.) and low-pressure steam (LPS, 250 °C, 3 bar g.).



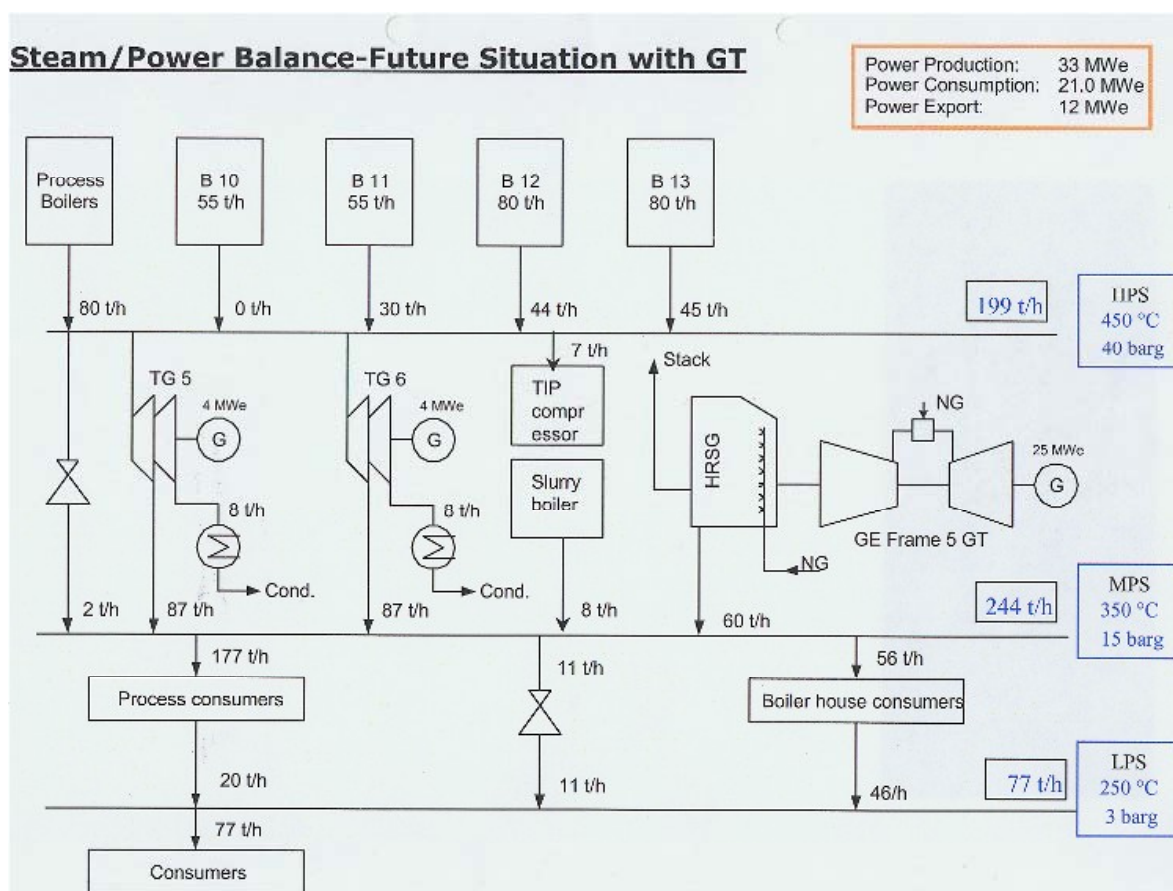


Figure E.6. Project configuration

The principal differences between the baseline and project configurations are summarised here. The introduction of the gas turbine cogeneration system increases overall power generation, from 18.9 MW to 33 MW, converting the plant from being a net importer of 2.1 MW to a net exporter of 12 MW. The refinery power demand is assumed to remain constant at 21 MW. The presence of the gas turbine reduces the need for two steam turbines, with the remaining turbines producing a total of 8 MW. The presence of heat recovered from the gas turbine means that the boilers are required to produce only 199 t/h high pressure steam (HPS), compared to 298 t/h in the baseline situation. This permits three boilers to operate at lower than rated capacity, with a fourth not needed at all. The production of medium and low pressure steam (MPS and LPS) are basically unchanged, there being small reductions (5 t/h and 4 t/h respectively) in internal demand of the boiler house (see bottom right) possibly since the demand for feed water pumping is reduced. Steam obtained as waste heat from refinery activities outside the boiler room / power house and steam delivered to refinery operations remain unchanged, and are not included in this analysis.

HPS is used entirely within the BRPS, mostly for generating electricity both in the baseline and project configurations. Thus the heat output of the BRPS supplied to the refinery comprises only MPS and LPS. The demand for MPS and LPS remains unchanged in the thermodynamic analysis for the baseline and project scenarios.

The project configuration includes natural gas consumption in the gas turbine.



The estimated natural gas mass consumption by the gas turbine system, MFC_{ng} (t /year), is given by:

$$MFC_{ng} \text{ (t / year)} = TFC_{ng} \text{ (max)} \cdot CF_{GT} \cdot 8760 \quad (\text{Eq. E.2})$$

where

TFC_{ng} = Gas turbine natural gas consumption rate (t/h); nominal value = 6.6 t/h,
 CF_{GT} = Gas turbine equivalent full-load capacity factor (fraction), and
8760 = no. of hours per year.

Convert to standard refinery fuel consumption (t SRF / year)

$$FC_{ng} \text{ (tSRF / year)} = \frac{MFC_{ng} \cdot CV_{ng}}{CV_{SRF}} \quad (\text{Eq. E.3})$$

where

CV_{ng} = lower heating value of natural gas (11,413 kcal / kg), and
 CV_{SRF} = lower heating value of Standard Refinery Fuel (9,673 kcal/kg)

For the project configuration, CF_{GT} , is assumed to be 1, and natural gas consumption would be 68,836 ton SRF/year. See details in spreadsheet Shell_MGM_BSL_ER.

In the project configuration, fuel consumption takes place in the boilers as well as in the gas turbine. While the heat recovery steam generator includes the possibility of co-firing with natural gas, this is not contemplated in the project configuration. In this case, the boiler production of HPS is reduced to 119 tonnes per hour. With a specific fuel consumption of 8.2 t SRF per 100 t HPS, as before, this fuel consumption amounts to 85,480 t SRF per year, about half the previous value.

SRF is standard refinery fuel, is used as an fuel energy unit at the refinery. The lower heating value of SRF is 9673 kcal/kg.

The boilers normally use asphalt and fuel gas as fuel, with a small amount of fuel oil also used occasionally. Fuel gas is a mixture of refinery gas and natural gas. In terms of calorific value and carbon content, refinery gas is remarkably similar to natural gas. Lower heating values of natural gas and refinery gas are 11413 kcal/kg and 11455 kcal/kg, respectively, while carbon content values are 73.07% y 74.08% w/w. Thus the two fuels (and any blends) have the virtually identical CO₂ emissions factor (on a weight basis, = 56.1 kg CO₂ per GJ).

We estimate consumption of each of the boiler fuels (asphalt, fuel gas and fuel oil) by considering a fixed percentage of overall fuel consumption, where the percentage is determined from historical values. The sheet "consumption profile" in the Excel file Shell_MGM_BSL_ER.xls shows these percentages to be 77.0%, 16.7% and 6.3% respectively. The individual fuel consumption values corresponding to total fuel consumption in the project scenario of 85,480 t SRF/year are given below.



The estimated fuel consumption in boilers, MFC_B (t SRF/year), is given by:

$$MFC_{fuel} (tSRF / year) = FC_B * f_{fuel} \quad (\text{Eq. E.4})$$

where FC_B = HPS production in the boilers (t HPS / year)
 f_{fuel} = historical fuel consumption rate fraction of each fuel, where
 $fuel$ = asphalt, fuel gas or fuel oil.

The project fuel consumption estimates are:

Asphalt	65,392 t SRF/year
Fuel gas	15,899 t SRF/year
Fuel oil	4,189 t SRF/year

Note that the project configuration also includes natural gas consumption (in the gas turbine) of 68,836 t SRF/year.

Once the fuel energy consumption has been determined, project emissions may be estimated as described below:

Estimated CO₂e emissions from fuel combustion within the project boundary, $E_{CO_2 comb}$ (t CO₂/year), are given by:

$$E(t CO_2 / year) = \sum_{fuel} FC_{fuel} \cdot (EF_{fuel} + MEF_{fuel} \cdot GWP(CH_4) + NEF_{fuel} \cdot GWP(N_2O)) \quad (\text{Eq. E.5})$$

where

FC_{fuel}	= annual fuel consumption for each fuel (GJ/year)
$fuel$	= asphalt, fuel gas, fuel oil or natural gas.
EF_{fuel}	= CO ₂ emission factor for each specific fuel (t CO ₂ /GJ, lower heating value basis)
MEF_{fuel}	= methane emission factor for each fuel combustion (t CH ₄ /GJ)
$GWP(CH_4)$	= global warming potential of CH ₄
NEF_{fuel}	= nitrous oxide emission factor for each fuel combustion (t N ₂ O/GJ)
$GWP(N_2O)$	= global warming potential of N ₂ O

The ex-ante project emissions for each fuel consumption are:

Asphalt	213,917 t CO ₂ e/year
Fuel gas	36,634 t CO ₂ e/year
Fuel oil	13,306 t CO ₂ e/year
Natural gas	158,465 t CO ₂ e/year



What is the value of *MEF*? Measured values of *MEF* for each fuel and type of equipment are not available from national data. Indeed, few such data are reported in *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories, Vol. 3, Reference Manual*. The closest values are for natural gas industrial boilers or residual fuel oil industrial boilers (Table 1-16, p. 1.54) and natural gas “commercial source” boilers or residual fuel oil “commercial source” boilers (Table 1-19, p. 1.57). In order to be conservative, we take the upper of these two estimate for each fuel. The values adopted are shown in the table below:

Methane Emission Factor _{fuel} , MEF_{fuel}	kg CH ₄ /TJ fuel
MEF_a (asphalt)	3.0
MEF_{fg} (fuel gas)	1.4
MEF_{fo} (fuel oil)	3.0
MEF_{ng} (natural gas)	1.4

We may apply these values of *MEF* to Eq (E.7) to estimate methane emissions from combustion for each fuel consumption in the boiler room and power station in the project scenario. We obtain CO₂-equivalent emissions of 283 tonnes per year. This is insignificant compared to the total project emissions, which add up to over 422,321 tonnes CO₂-equivalent per year (see spreadsheet [Shell_MGM_BSL_ER.xls](#), Sheet “Emiss. Red.”). Thus the GHG emissions from methane in combustion is about 0.07 % of total project emissions. *While we include methane emissions in combustion in this PDD, they may well be neglected.*

What is the value of *NEF*? There are little quantitative data on N₂O emissions from combustion, some of which are in *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Reference Manual*. The values adopted are shown in the table below:

Nitrous Oxide Emission Factor _{fuel} , NEF_{fuel}	kg N ₂ O /TJ fuel
NEF_a (asphalt)	3.0
NEF_{fg} (fuel gas)	2.3
NEF_{fo} (fuel oil)	3.0
NEF_{ng} (natural gas)	2.3

While the absolute value of the emissions factor for nitrous oxide in kg/TJ is similar to that for methane, the CO₂ equivalent emissions is much higher, because of the considerably higher GWP of N₂O. N₂O emissions for the project are estimated to be 2,588 tonnes CO₂-equivalent per year, compared to total project emissions of over 422,321 tonnes CO₂-equivalent per year. Thus, nitrous oxide emissions are relatively small, about 0.6% of total project emissions.

The spreadsheet [Shell_MGM_BSL_ER.xls](#) details the *ex-ante* calculations of baseline and project emissions, and estimates of emissions reductions. The results are summarized in the last sheet denominated “Emiss. Red.”.

Total project emissions from fuel combustion within the project boundary in the project scenario are estimated to be 422,321 tCO₂ equivalent per year.

**E.2. Estimated leakage:**

>>

Project implementation implies greatly increased consumption of natural gas at the refinery. Methane is the principal component of natural gas and methane emissions at the gas wells, leakage from the natural gas pipeline supplying the refinery, as well as any leaks within the refinery may be considered leakage, also in the CDM sense, insofar as these emissions would not have occurred without project implementation.

Below we consider methane leakage from natural gas production, transport, and distribution.

Methane leakage from natural gas production. Natural gas that would be used in the project site is extracted in gas fields in the West and South of Argentina. However, country and well-specific data on methane emissions from natural gas production are not available for Argentina. We thus use region specific values indicated in the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Reference Manual*. Table 1-64 page 1.131 indicates values of 39,590 to 96,000 kg/PJ of gas produced. Since gas leaks are a small part of gas production, we may take the leakage to be approximately the same as kg per PJ of gas consumption, as well. We assume an average value of 70,000 kg/PJ of gas consumed at the project site. This is the same as 0.07 kg/GJ of gas consumed.

Methane leakage from natural gas pipelines and distribution network. Since measured data on pipeline leakage are not available in Argentina, we use standard estimates as suggested in *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Reference Manual*. Table 1-64, p. 1.131 indicates values of 116,000 to 340,000 kg of methane per PJ of natural gas consumed in the “Rest of the world” region where Argentina would fall. We assume an average leakage value of 230,000 kg/PJ, i.e. 0.23 kg/GJ of gas consumed. In all cases, the energy content (GJ) is based on the lower heating value of the fuel.

Estimated fugitive methane emissions (natural gas production, pipeline and distribution leaks), E_{fug} (t CH₄/year), are given by:

$$E_{fug} \text{ (t CH}_4 \text{ / year)} = \frac{FC_{ng} \cdot MLR}{10^6} \quad (\text{Eq. E.6})$$

where FC_{ng} = natural gas consumption (GJ/year)

MLR = methane leakage rate (kg CH₄/GJ of natural gas consumption, LHV basis)

Convert to carbon dioxide equivalent emissions, $E_{equiv \text{ } fug}$ (t CO₂ equiv/year)

$$E_{equiv \text{ } fug} \text{ (t CO}_2 \text{ - equiv / year)} = E_{fug} \cdot GWP(CH_4) \quad (\text{Eq. E.7})$$

where $GWP(CH_4)$ = global warming potential of methane = 21



Considering gas production, transport and distribution, we consider a methane emissions factor from leakage to be $(0.07 + 0.23)$ or 0.30 kg/GJ gas consumption. Thus **MLR = 0.30 kg/GJ of natural gas energy consumption (lower heating value basis)**.

While the fugitive methane emissions associated with project natural gas consumption are significant, it should be noted that the baseline also involves natural gas consumption in power plants elsewhere in the interconnected power grid. However, the methodology for grid-connected power generation (ACM0002) only accounts for CO_2 emissions. Thus, we do not include fugitive methane emissions associated with natural gas consumption in the project either. The alternative would have been to include these fugitive emissions in the grid-connected power generation, but since that is based on an approved consolidated methodology (ACM0002), we choose to modify the procedures in this PDD rather than modify ACM0002.

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

>>

Total project emissions are given by the sum of the elements in E.1 and E.2 analysed above:

$$E_{total} (\text{tonne } \text{CO}_2 - \text{equiv} / \text{year}) = E + E_{equiv \text{ fug}} \quad (\text{Eq. E.8})$$

where E refers to CO_2e emissions from combustion of each fuel,

Ignoring leakage, *ex-ante* estimates of total project emissions remain unchanged at $422,321 \text{ t CO}_2\text{e/year}$.

During the project, these emissions and reductions with respect to baseline emissions would be determined by actual monitored data of the boiler room and power station.

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

>>

Baseline GHG emissions are determined by the new methodology proposed with this PDD, and applied here.

Baseline GHG emissions *within the project boundary* correspond to emissions from fuel combustion at the boiler room and power station (BRPS) in the absence of the project activity. As shown in Fig. (E.5), baseline electricity imports from the grid were typically 2.1 MW . Thus there are additional baseline emissions arising from electricity purchases from the interconnected power grid in the baseline scenario. Furthermore, in the project configuration (see Fig. E.6) the cogeneration system power output exceeds refinery demand with an average of 12.0 MW sold through the power grid. In the absence of the project activity, this amount of additional electric power would need to be generated at other power plants in the grid. Thus, power exports from the cogeneration system in the *project* scenario would result in additional emissions in the *baseline* scenario. Baseline emissions thus comprise the following components:

- a) **CO_2e combustion.** CO_2 equivalent emissions from combustion, corresponding to the fuels used in the BRPS, in the baseline situation, i.e. if the gas turbine system did not provide heat and electricity to the refinery.
- b) **CH_4 leaks.** CH_4 emissions from natural gas production and leaks in the pipeline supplying natural gas to the factory, associated with the natural gas consumption in the baseline. There is a small



amount of natural gas used in the baseline situation, mixed with refinery gas, to provide a consistent combustion.

- c) **CO₂ from plant electricity deficit in baseline, purchased through the grid.** CO₂ emissions associated with the electricity that would have to be purchased from the power grid in the baseline situation, since the power output of the boiler room / power station is not enough to meet refinery needs.
- d) **CO₂ emissions from surplus electricity provided by project.** With the project situation, there is surplus electricity generation, which is sold through the power grid. This generation offsets CO₂ emissions elsewhere in the grid, emissions that would be present if the project were not implemented. We consider these emissions to be another component of baseline emissions.

The methodology and formulae for estimating each of these components of baseline emissions are described in the new methodology presented with this PDD, and applied below.

The first component (a) of baseline emissions is proportional to fuel consumption of the boilers in the boiler room and power station (BRPS) in the baseline situation. The constant of proportionality depends on the heating value of each fuel, and the emissions factors of the fuel (for CO₂, CH₄ and N₂O from combustion) are expressed as tonne per GJ. The emissions of methane and nitrous oxide need to be converted to equivalent tonnes of CO₂ using their respective GWP.

The second item (b) is proportional to natural gas consumption in the baseline. We estimate this as a proportion of the refinery fuel consumption, using historical data. The constant of proportionality (methane leakage rate, MLR) is the same as explained for project emissions. However, for consistency with ACM0002, we ignore fugitive methane emissions from both baseline and project emissions.

The third item (c) is proportional to the *electricity purchased through the power grid* in the *baseline* situation. The constant of proportionality is the emissions factor for electricity generation, calculated in Annex 3 of this PDD.

The fourth item (d) is proportional to the *electricity sold through the power grid* in the *project* scenario. The constant of proportionality is the same emissions factor for grid-connected electricity generation, calculated in Annex 3.

While baseline fuel combustion can be determined from past consumption data, prior to project implementation, project fuel consumption can only be determined from a thermodynamic cycle analysis of changes in project configuration. For consistency in assumptions on steam flow rates and electricity generation, *ex-ante* estimations of baseline and project fuel consumption are both determined from thermodynamic analysis.

Ex-post project emissions are determined from monitored data on fuel consumption and net electricity sold to the grid. To allow for changes in industrial activity that may take place, *ex-post* emissions calculations will be determined in a dynamic manner also from project monitoring data. See Monitoring Plan in Annex 4.

Ex ante estimates from thermodynamic analysis

In the baseline configuration (see Fig. E.5), the boilers need to generate 218 tonnes per hour of high pressure steam (HPS). Measurements indicate an average boiler specific fuel consumption of 8.2 tonnes



of SRF (standard refinery fuel) per 100 tonnes of HPS. Note that, while several boilers are involved, these measurements indicate that the average specific fuel consumption is remarkably constant, reflecting their optimised operation. This corresponds to a boiler fuel consumption of 156,594 tonnes SRF per year.

The boilers use asphalt, fuel gas and fuel oil, and we estimate consumption of each fuel based on the percentages from historic data.

Ex-ante estimates of baseline fuel consumption components are:

Asphalt 119,733 ton SRF/year

Fuel gas 29,153 ton SRF/year

Fuel oil 7,708 ton SRF/year

See details in spreadsheet Shell_MGM_BSL_ER.

Once the fuel energy consumption has been determined from thermodynamic analysis, *ex ante* estimates of baseline emissions from fuel combustion may be estimated as described below.

Estimated CO₂-equivalent emissions from fuel combustion in the baseline scenario, *BE* (t CO₂e/year) are given by:

$$BE(\text{tonne CO}_2 / \text{year}) = \sum_{\text{fuel}} BFC_{\text{fuel}} \cdot (EF_{\text{fuel}} + MEF_{\text{fuel}} \cdot GWP(\text{CH}_4) + NEF_{\text{fuel}} \cdot GWP(\text{N}_2\text{O})) \quad (\text{Eq. E.10})$$

where BFC_{fuel} = annual fuel consumption for each fuel in the baseline (GJ/year)

EF_{fuel} = CO₂ emission factor for each specific fuel (kg CO₂/GJ, *lower heating value basis*)

MEF_{fuel} = methane emission factor for each fuel combustion (t CH₄/GJ)

$GWP(\text{CH}_4)$ = global warming potential of CH₄

NEF_{fuel} = nitrous oxide emission factor for each fuel combustion (tonne N₂O/GJ)

$GWP(\text{N}_2\text{O})$ = global warming potential of N₂O

The ex-ante estimates of baseline emissions from fuel consumption are:

Asphalt 391,881 t CO₂e/year

Fuel gas 67,111 t CO₂e/year

Fuel oil 24,375 t CO₂e/year

EF_{fuel} depends on the fuel, and is best determined from national data sources, as indicated in the baseline methodology (NMB) presented with this PDD.

As in the case of project emissions, methane emissions from fuel combustion is negligible, while nitrous oxide emissions are relatively small, about 0.3% of total baseline emissions.

The details of project and baseline emissions are to be found in the Excel file [Shell_MGM_BSL_ER.xls](#).



b) CH₄ leaks from natural gas consumption in baseline are not considered here, for consistency, as explained in section E.2.

c) CO₂ from plant electricity deficit in baseline, purchased through the grid.

Prior to project implementation, the refinery purchased electricity from the power grid in order to meet demand. Part of the demand was met by self generation and the emissions associated have been included in the emissions from fuels used within the project boundary. Here we need to account for the emissions that take place at power plants of the interconnected power grid, located outside the project boundary, as a result of electricity purchases by the refinery through the power grid.

Emissions for electricity purchases in the baseline, $BE_{elec, baseline purchase}$ are given by

$$BE_{elec, baseline purchase} = \frac{NBEP \cdot EF_{elec gen}}{1 - TDL} \quad (\text{Eq. E.11})$$

where

$NBEP$ = Net baseline electricity purchases (MWh/year),
 $EF_{elec gen}$ = Emissions factor for grid power generation (t/MWh) , and
 TDL = Transmission and distribution losses (fraction)

Ex-ante baseline parameters:

Electricity purchases = 2.1 MW x 8760 hours/year = 18,396 MWh/year
 EF = 0.365 t CO₂ / MWh
 TDL = 0.14

Applying the formulae above,

$$BE_{elec, baseline purchase} = 7,807 \text{ t CO}_2\text{e/year}$$

d) Baseline CO₂ emissions from surplus electricity provided by project to the grid.

Following project implementation, the generation capacity at the refinery would be greatly increased, exceeding refinery demand. Excess electricity would be sold through the power grid. In the absence of the project activity, i.e. in the baseline, this electricity would have to be generated by other power plants in the power grid. Thus baseline emissions would increase following project implementation.

Baseline emissions for electricity sold in the project scenario, $BE_{elec, project sales}$ are given by

$$BE_{elec, project sales} = NPES \cdot EF_{elec gen} \quad (\text{Eq. E.12})$$

where

$NPES$ = Project electricity sales (MWh/year) and
 $EF_{elec gen}$ = Emissions factor for grid power generation, as in Eq. E.14.

Ex-ante project parameters:

Electricity sales = 12 MW x 8760 hours/year = 105,120 MWh/year
 EF = 0.365 t CO₂ / MWh

Applying the formulae above

$$BE_{elec, project sales} = 38,369 \text{ t CO}_2\text{e/year}$$



Note that ex-post baseline emissions for electricity sold in the project scenario will be determined from project monitoring data.

The emissions factor for grid power generation, $EF_{elec\ gen}$, is determined using the approved consolidated methodology ACM0002, as shown in Annex 3.

As we have mentioned before, *ex-ante* baseline and project emissions are also to be found in the spreadsheet [Shell_MGM_BSL_ER.xls](#).

Ex-ante baseline emissions are estimated to be 529,544 tonnes CO₂equivalent per year. Note that ex-ante baseline (and project) emissions are values reported in this PDD in order to estimate these emissions. Actual emissions reductions will be determined from monitored data.

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

>>

Emissions reductions are determined *ex ante* using the spreadsheet [Shell_MGM_BSL_ER.xls](#).

Ex-ante emissions reductions are estimated to be 107,222 tonnes CO₂equivalent per year.

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

>>

The *ex-ante* emissions reductions are estimated to be 107,222 tonnes CO₂equivalent per year. Note that this is constant over time. However, actual emissions reductions will be based on monitored data with baseline emissions determined on a dynamic basis. These emissions reductions are likely to be different from the *ex-ante* estimate, and will vary in time.



Years	Estimation of project activity emissions in tonnes of CO ₂ e	Estimation of baseline emissions in tonnes of CO ₂ e	Estimation of leakage in tonnes of CO ₂ e	Estimation of emission reduction in tonnes of CO ₂ e
Year 1	422,321	529,544	0	107,222
Year 2	422,321	529,544	0	107,222
Year 3	422,321	529,544	0	107,222
Year 4	422,321	529,544	0	107,222
Year 5	422,321	529,544	0	107,222
Year 6	422,321	529,544	0	107,222
Year 7	422,321	529,544	0	107,222
Total (tonnes of CO ₂ e)	2,956,247	3,706,808	0	750,554

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

>>

As indicated in the instructions from the CDM Executive Board, Environmental impacts are not required for draft PDDs submitted with new methodologies, as is the case here.

F.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:

>>

SECTION G. Stakeholders' comments

>>

As indicated in the instructions from the CDM Executive Board, Stakeholder comments are not required for draft PDDs submitted with new methodologies, as is the case here.

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

>>

G.2. Summary of the comments received:

>>

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

>>

Annex 1**CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY**

Organization:	MGM International, Ltda.
Street/P.O.Box:	801 Brickell Key Blvd., # 405
Building:	
City:	Miami
State/Region:	Florida
Postfix/ZIP:	33131
Country:	USA
Telephone:	+1-305-735-8424
FAX:	+1-305-418-7493
E-Mail:	cdm@mgminter.com
URL:	
Represented by:	
Title:	President
Salutation:	Mr.
Last Name:	Monroy
Middle Name:	Gerardo
First Name:	Marco
Department:	
Mobile:	
Direct FAX:	+1-305-418-7493
Direct tel:	+1-305-735-8424
Personal E-Mail:	marcogmonroy@mgminter.com



Organization:	Shell Compañía Argentina de Petróleo S.A.
Street/P.O.Box:	Sargento Ponce 2318
Building:	Refinería Buenos Aires
City:	Dock Sud
State/Region:	Buenos Aires
Postfix/ZIP:	(1871)
Country:	Argentina
Telephone:	+(54 11)5030-3000
FAX:	+(54 11)5030-3500
E-Mail:	
URL:	
Represented by:	
Title:	
Salutation:	
Last Name:	Bergerman
Middle Name:	Damián
First Name:	Sergio
Department:	
Mobile:	
Direct FAX:	+(54 11)5030-3000 ext 3622
Direct tel:	+(54 11)5030-3500
Personal E-Mail:	Sergio.s.bergerman@shell.com

Organization:	Shell Trading International Limited
Street/P.O.Box:	80 Strand
Building:	80 Strand
City:	London
State/Region:	
Postfix/ZIP:	WC2R 0ZA
Country:	United Kingdom
Telephone:	+44 20 7546 5126
FAX:	+44 20 75465134
E-Mail:	roon.osman@shell.com
URL:	http://www.shell.com
Represented by:	
Title:	Ms
Salutation:	
Last Name:	Osman
Middle Name:	S
First Name:	Roon
Department:	Environmental Products Trading Business
Mobile:	07984767099
Direct FAX:	+44 20 75465134
Direct tel:	+44 20 7546 5126
Personal E-Mail:	roon.osman@shell.com

Organization:	Showa Shell Sekiyu K.K.
---------------	-------------------------



Street/P.O.Box:	3-2, Daiba 2 chome, Minato-ku
Building:	Daiba Frontier Building
City:	Tokyo
State/Region:	
Postfix/ZIP:	135-8074
Country:	Japan
Telephone:	+81-3-5531-5627
FAX:	+81-3-5531-5767
E-Mail:	Toshiko.Okamoto@showa-shell.co.jp
URL:	www.showa-shell.co.jp
Represented by:	
Title:	GHG manager
Salutation:	Mr.
Last Name:	Toshihiko
Middle Name:	
First Name:	Okamoto
Department:	New Business Development Division
Mobile:	
Direct FAX:	+81-3-5531-5767
Direct tel:	+81-3-5531-5627
Personal E-Mail:	Toshiko.Okamoto@showa-shell.co.jp



Annex 2

INFORMATION REGARDING PUBLIC FUNDING

No funds from public national or international sources are involved in any aspect of the proposed project.



Annex 3

BASELINE INFORMATION

Most of the assumptions related to the determination of baseline emissions were provided in the relevant sections of the PDD. In this Annex, we limit ourselves to summarising the procedure used to determining the emissions factor of grid-connected electricity generation, $EF_{elec\ gen}$.

In the baseline situation, the refinery purchases electricity through the power grid, and in the project situation, electricity is sold through the power grid. In the first case, electricity generation elsewhere required to supply the refinery leads to additional emissions than those accounted for in the project boundary. In the second case, the project actually supplies electricity to the grid, thus offsetting emissions elsewhere. By CDM tradition, these emissions offset are considered as baseline emissions, in the sense that such emissions would take place if the project did not supply electricity to the grid.

A number of methodologies have been submitted by CDM project developers to determine emissions factor that would be offset by renewable electricity. Upon revision of these methodologies, the Meth Panel has published the so-called “Consolidated baseline methodology for grid-connected electricity generation from renewable sources.” Following the 15th Meeting of the CDM Executive Board in early September 2004, this methodology was formally approved and designated ACM0002⁴ (ACM = Approved Consolidated Methodology).

At the same time, the Meth Panel and the CDM Executive Board also indicated that for the electricity offset by a cogeneration system, the same consolidated methodology be used, even though the project did not deal with generation using renewable sources. In this regard it is useful to note that if project emissions from electricity generation or cogeneration using non renewable resources are properly taken into account, then the baseline emissions refer to the emissions offset by this generated electricity is no different from the case in which the generation were from renewable sources. Thus, the Methodology Panel and the CDM Executive Board is entirely correct in not treating separately these baseline emissions.

ACM0002 indicates that the emissions factor is a so-called “combined margin”, which is determined in three steps:

1. **Calculate the Operating Margin emission factor**
2. **Calculate the Build Margin emission factor**
3. **Calculate the baseline emission factor Combined Margin** as the weighted average of the Operating Margin emission factor and the Build Margin emission factor

Four different procedures are indicated for determining the operating margin. These are denominated:

- (a) Simple Operating Margin
- (b) Simple Adjusted Operating Margin
- (c) Dispatch Data Analysis Operating Margin
- (d) Average Operating Margin.

Three of these procedures (a, b and d) are relatively simple, but one procedure (c-dispatch analysis) requires access to an inordinate amount of data on the operation of all power plants in the grid connected

⁴ Approved consolidated baseline methodology ACM0002 “Consolidated baseline methodology for zero-emissions grid-connected electricity generation from renewable sources”, Published as Annex 2 of the report of the 15th Meeting of the CDM Executive Board, Sept 3, 2004.



to the project in question, on an hour-by-hour basis, for the entire project lifetime. Data at this level are not available to the public. To perform a dispatch analysis, we would need to know:

- which power plants were dispatched for each hour during the entire monitoring period;
- what the merit order of dispatch was, which depends on the fuel efficiency and fuel prices for thermal power plants, the availability of dispatchable hydroelectric power plants, as well as knowledge of system operation in order which power plants out of merit order need to be dispatched in order to meet system and voltage stability requirements, as well as because of transmission bottlenecks.

The procedure is further complicated by the fact that:

- fuel prices vary; generators may declare values below market prices and may do so, for instance where they have “take or pay” contracts with fuel suppliers, in order to see their equipment dispatched;
- there are restrictions on natural gas availability especially during winter months;
- some power plants can operate on alternative fuels, others not;
- fuel price changes, fuel switching or system stability problems can all affect the merit order

Moreover, hour-by-hour dispatch analysis provides a valid answer to which power plants are offset by the project generation only for power grids where there is no appreciable energy storage. Electricity is “stored” indirectly by storing water in reservoirs, whose height can be varied over the course of hours, days, or even months in order to take into account both demand variations as well as seasonal rains. Specifically, in Argentina, dispatchable hydroelectric power plants make a significant contribution to meeting demand during the peak evening hours. Dispatch analysis would indicate that 1 MW by a project activity during a peak hour would mostly displace hydro. This is not true, since the water saved at that hour will not simply be spilled out. The water would be saved and used at another hour, where it would offset higher cost generation based on fuel combustion. Since fossil-fuel power plants are used for all hours, the power plants offset would always be thermal power plants.

In many non-Annex 1 countries, there are large amounts of such “dispatchable” hydro, whereby hydroelectric generation may offset emissions from a thermal power plant at another time.

The problem of determining which power plant in the power system is offset by project generation becomes even more complex when reservoir water storage extends over longer periods. Many non Annex 1 countries have rainy and dry seasons, and hydroelectric reservoirs are designed to carry over water from rainy to dry seasons.

Hydroelectric power plants are dispatched not according to a merit order expressed in terms of specific fuel consumption and fuel price, but rather than on a model of optimal management of water resources. The water flow from a given reservoir affects water availability and power generation potential of power plants downstream. Moreover, water is often also used for irrigation, which places other restrictions on how water is stored in or released from a reservoir.

In many Annex 1 countries, the hydroelectric resources are largely saturated, and make up a small part of total generation. Thus supply and demand are matched by an hour-by-hour balancing of thermal power plants available and power demand. In such cases, an hourly dispatch analysis could provide a reasonable estimate of power plants offset by hourly generation from a given project activity.

In any system with significant amounts of dispatchable hydro, such as the case for Argentina, an hour-by-hour analysis can lead to an erroneous estimate of emissions avoided from the power grid through power generated by a given project activity.



ACM0002 states:

“Dispatch data analysis should be the first methodological choice. Where this option is not selected project participants shall justify why and may use the simple OM, the simple adjusted OM or the average emission rate method taking into account the provisions outlined hereafter.”

We have argued above that dispatch analysis based on hourly data is not appropriate for power generation connected to the Argentine power grid. A more reliable estimate can indeed be obtained from the Simple Operating Margin or the Adjusted Simple Operating Margin approaches described in ACM0002. The results are presented below:

Simple Operating Margin

ACM0002 states that the Simple OM method can only be used where low-cost/must run (LCMR) resources constitute less than 50% of total grid generation in: 1) average of the five most recent years, or 2) based on long-term normals for hydroelectricity production.

ACM0002 further states:

Low operating cost and must run resources typically include hydro, geothermal, wind, low-cost biomass, nuclear and solar generation. If coal is obviously used as must-run, it should also be included in this list, i.e. excluded from the set of plants.

In the case of Argentina, LCMR would include nuclear power plants and run-of-river hydropower plants that do not allow water storage, and are therefore not dispatched. To this list, one would also add self-generation equipment at industrial sites, which declare zero marginal cost in order to be always dispatched. We would also include power plants that are forced to operate, despite being not included in economic dispatch, for a variety of reasons such as for system and voltage stability (denominated S&T) or for other reasons⁵.

The energy generation of power plants in the national grid of Argentina, according to these categories, are shown in Table 3.1.

⁵ These other reasons include: (a) equipment start up, (b) operating cost for start up and stopping (when it is cheaper to keep a forced generator operating than to start up another one); (c) for requirements of downstream power plants; (d) for generator trials, (e) for time for start up and stopping, (f) forced by the distribution company for saturation of its sub-transmission equipment, (g) forced by power requirement in a given area (and transmission bottlenecks), (h) generating equipment that become unavailable, etc.



Table 3.1. Electricity generation and emissions by type of power plant in the Argentina national grid.				
Type of generation	Source	Year of data July 2003 to June 2004		Emission factor, tCO ₂ /MWh
		Generation, MWh	Emissions, tCO ₂	
Forced S&T	Hydro	12,000	0	0.000
	Fuel oil	88,277	69,422	0.786
	Natural gas	454,013	282,085	0.621
	"Gas oil"	7,942	7,806	0.983
Other forced	Hydro	1,902,556	0	0.000
	Coal	147,747	148,821	1.007
	Fuel oil	365,753	291,656	0.797
	Natural gas	1,379,859	626,549	0.454
	"Gas oil"	47,461	31,582	0.665
Dispatched	Hydro	10,854,759	0	0.000
	Coal	421,775	424,841	1.007
	Fuel oil	2,218,527	1,753,459	0.790
	Natural gas	35,431,664	15,184,697	0.429
	"Gas oil"	316,875	181,972	0.574
Zero oper. cost (Low-cost / must-run)	Uranium	7,147,326	0	0.000
	Base Hydro	19,804,557	0	0.000
	Self generation & cogeneration			
	Natural gas	5,745,777	2,504,351	0.436

Note: "Gas oil" is light diesel (distillate).

The energy generation of all power plants connected to the Argentina MEM grid is reported monthly by the wholesale power management company (CAMMESA). Each thermal power plant must report the specific fuel consumption for their equipment. This is a function of load factor and is expressed as a polynomial. However, in this analysis we consider the full-load or nominal values, in order to determine fuel consumption corresponding to reported electricity generation data. The fuel consumption values are multiplied by the CO₂ emissions factors for the fuels involved in order to estimate total emissions for each power plant. Monthly values are summed to provide annual totals. The values in Table 3.1 correspond to the period from July 2003 to June 2004.

Data from different power plants are grouped into the categories shown in the first column of Table 3.1, and summed to show the total electricity generation and total CO₂ emissions of each category using each energy source. The ratio of emissions (tCO₂/year) to power generation (GWh/year) is the emissions factor. The resulting values are shown in the last column of Table 3.1.

Note that Low-cost /must-run electricity generation added up to 32,697,660 GWh out of a total of 86,346,867. Thus LCMR represents 38% of the total, which is less than 50%, and the Simple Operating Margin approach is applicable, as per ACM0002.

While the data in Table 3.1 are from a recent one-year period, Figures 3.1 and 3.2 respectively show that absolute and relative contributions of thermal, hydro and nuclear generation to the total.

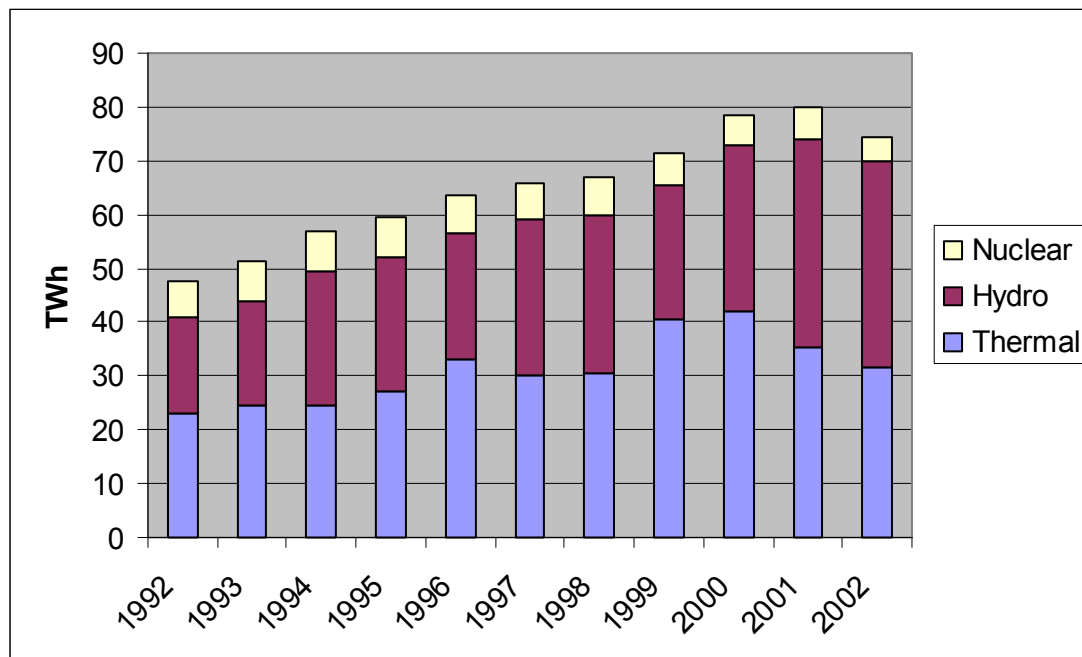


Figure 3.1. Thermal (grey, bottom), hydro (purple, medium) and nuclear (cream, upper) electricity generation in Argentina, from 1992 to 2002. Demand growth ceased in 2001 and demand actually fell during 2002. Higher rainfall in 2001 and 2002 meant that thermal generation fell sharply in 2001 and 2002.

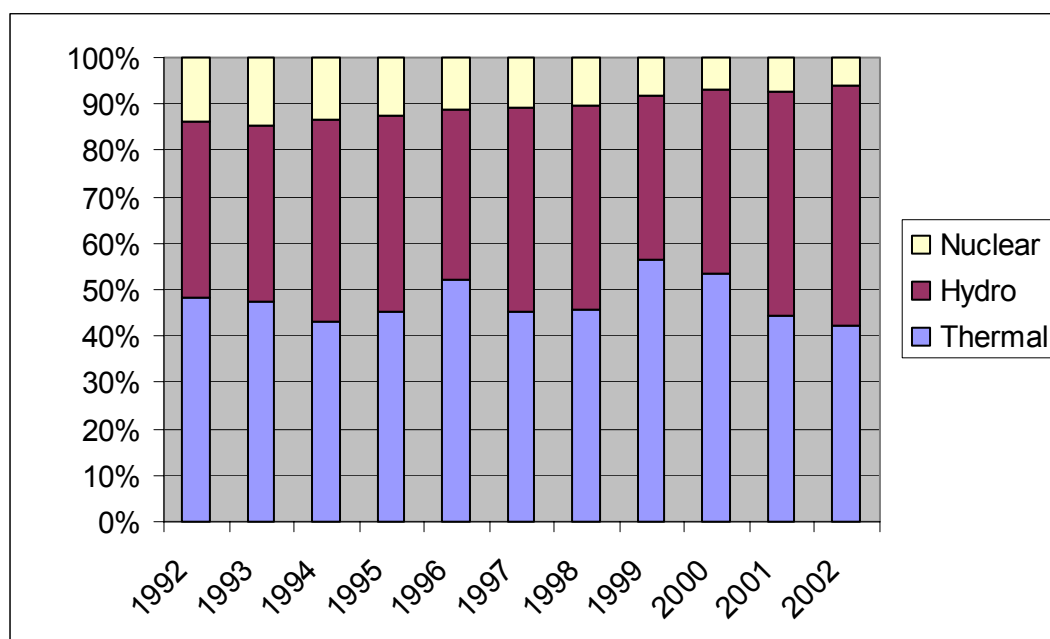


Figure 3.2. Relative contribution of thermal (grey, bottom), hydro (purple, medium) and nuclear (cream, upper) electricity generation in Argentina, from 1992 to 2002. On average, about half of total generation is from thermal power plants using fossil fuels. Somewhat under half of hydro may be considered low-cost /must-run (LCMR), so that this component, together with nuclear electricity make up less than half of total generation in any of these years.

Excluding LCMR power generation (as defined above), we determine that total generation of 49,243,599 MWh resulted in total emissions of 17,544,968 t CO₂ equivalent, so that the emissions factor corresponding to the operating margin is 0.356 tCO₂/MWh.

Alternatively, we may consider the LCMR power plants to be strictly the nuclear power plants and the run-of-the-river hydro. In this case, total generation of 59,394,985 MWh resulted in total emissions of 21,507,240 t CO₂ equivalent, so that the emissions factor corresponding to the operating margin would be 0.362 tCO₂/MWh.

This value is not substantially different from the operating margin calculated using the previous assumption. In order to be conservative we choose the previous estimate of **0.356 tCO₂/MWh** as the operating margin for power generation in this grid.

Simple Adjusted Operating Margin

This is a variation of the Simple Operating Margin, where the power sources (including imports) are separated in low-cost/must-run power sources and other power sources. We are required to determine what fraction of time, the low-cost/must-run power plants are on the margin. See Figure 3.3.

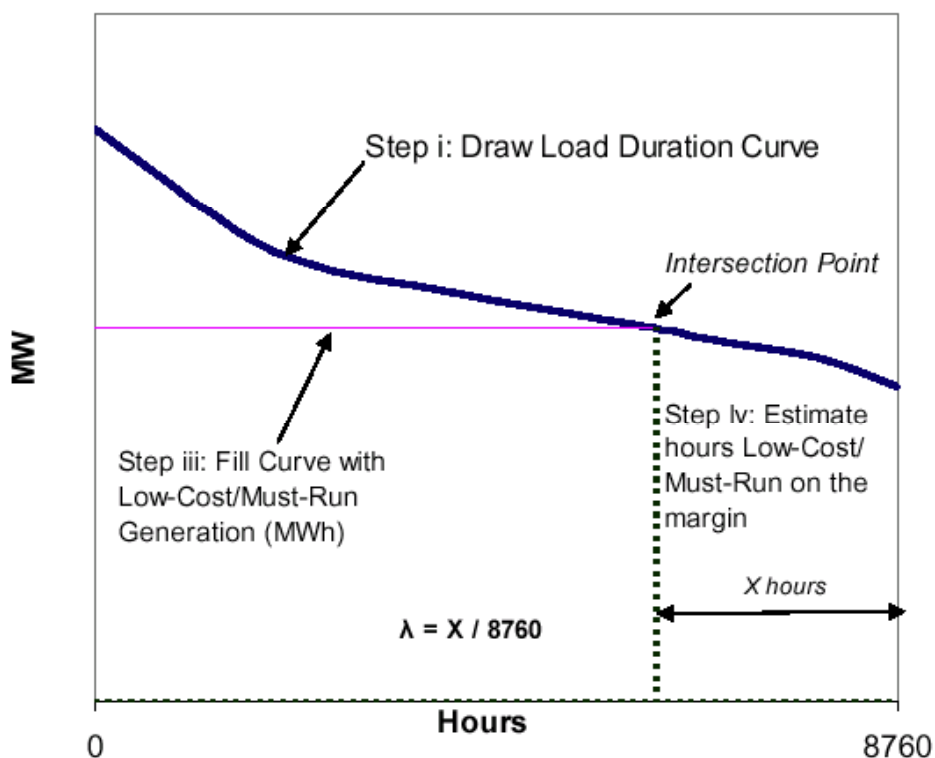


Figure 3.3. Determination of lambda (λ) as fraction of total hours in a year that low-cost / must-run (LCMR) generation sources are at the margin. The value of λ is given by the intersection of the load duration curve and the supply from LCMR power plants (horizontal line, magenta). (Source: Fig. 1 of ACM0002.)

This figure for the national power grid of Argentina is shown in Figure 3.4, where we can see that the intersection takes place on the right vertical axis. In other words, LCMR power plants never operate at the margin, and $\lambda = 0$. In this case, there is no difference between the Simple Operating Margin and the Adjusted Operating Margin.

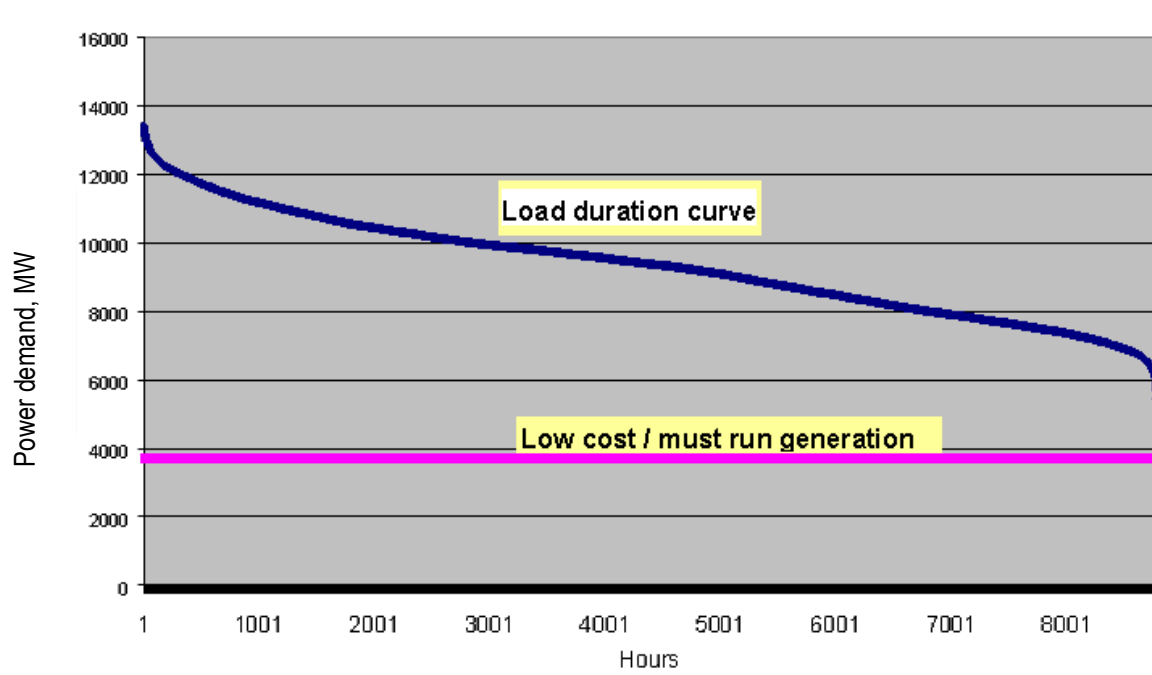


Figure 3.4. Determination of lambda (λ) for the national power grid of Argentina

Step 2. Calculate the build margin

According to ACM0002, the build margin is determined by the average emissions factor of a sample of recently built power plants. The sample may be the most recent five power plants built if they add up to more than 20% of the total generation in the grid. If not, the sample must include enough of the most recently built power plants in order that together they represent at least 20% of the total generation.

While this procedure appears straightforward, its application raises a number of problems, at least for the Argentina national grid. As we have mentioned in Section B.3, both the macroeconomic situation in Argentina and the rules for the operation of the wholesale power market have inhibited the construction of new power plants. Most recent power plants have in fact been adding components to power plants already started. Typically these are natural gas-fired combined cycle power plants which comprise two gas turbine power plants and a steam turbine power plant. The installation of each component is listed as a “new construction” with its output power reported. However, the wholesale market sees all components as a single power plant and only reports the total energy output from the system, independent of the number of components that may be installed and operating at any given time.

Moreover, the emissions factor of individual components is not relevant since waste heat from the gas turbines is recovered and used in steam turbines. Thus the specific fuel consumption of the entire system is lower than that of any of its component parts. For this reason, we have considered, as a conservative assumption, that all portions of combined-cycle power plants recently installed would have the emissions factor as if the power plant was operating in combined cycle. Characteristics of principal power plants added in recent years are shown in Table 3.2 below.



Table 3.2. Recent power plant constructions in the MEM power grid, Argentina

Entry date Year Mon.	Power plant	Type	Power MW	Specific cons. kcal/kWh	Generation		Acum %	Fuel consumption		Cum. Spec. Cons. TJ/GWh	Cum. Emis. Factor kg/MWh
					GWh	Acum		TJ	Acum TJ		
2004apr	San Nicolás	GT	24.0	3176	0.0	0.0	0%	0	0		
2003	AES Caracoles (Q Ullum)	Hydro	45.0		192.0	192.0	0%	0	0	0.00	0.0
2003	Consortio Potrerillos (A. Condarco)	Hydro	74.0		253.0	445.0	1%	0	0	0.00	0.0
2003jun	Pluspetrol Norte	GT	116.4	2613	117.6	562.6	1%	1287	1287	2.29	128.3
2002dec	Consortio Potrerillos (Cacheuta N.+El Carrizal)	Hydro	96.0		156.9	719.5	1%	0	1287	1.79	100.3
2002nov	Petrolera Chevron San Jorge	GT	18.5	3500	146.0	865.5	1%	2140	3426	3.96	222.1
2002aug	San Miguel de Tucuman	CC	250.0	1725	1645.1	2510.6	3%	11881	15307	6.10	342.0
2002aug	Consortio Potrerillos (El Carrizal)	Hydro	17.0		70.8	2581.3	3%	0	15307	5.93	332.7
2002jun	Pluspetrol Norte	GT	116.4	2613	117.2	2698.5	3%	1282	16589	6.15	344.9
2002mar	San Miguel de Tucuman	GT	124.0	1725	815.9	3514.4	4%	8927	25516	7.26	407.3
2001nov	AES Paraná	CC	830.0	1508	3944.0	7458.4	9%	24901	50417	6.76	379.2
2001oct	San Miguel de Tucumán	CC	382.0	1725	2294.0	9752.4	12%	16568	66985	6.87	385.3
2001jun	Dock Sud	CC	773.0	1528	4208.0	13960.4	17%	26920	93905	6.73	377.4
2000may	Puerto Nuevo	CC	798.0	1487	4839.0	18799.4	23%	30127	124031	6.60	370.1
2000sep	Autogenerador Entre Lomas	GT	15.0	3252	23.0	18822.4	23%	313	124344	6.61	370.6
1999sep	Costanera	CC	851.0	1486	4838.0	23660.4	29%	30100	154444	6.53	366.2
1999oct	Agua del Cajón	CC	662.0	1808	4477.0	28137.4	34%	33890	188334	6.69	375.5

Notes: GT: open-cycle gas turbine; CC: combined cycle plant.



Some power plants can operate on more than one fuel. Indeed, in the winter, the demand for natural gas peaks because of space heating demand, and gas pipelines become saturated. In these periods, some power plants (and industrial consumers with interruptible gas supply) of natural gas switch to liquid fuels, especially fuel oil or diesel, depending on the power plant equipment involved. Thus, power plants that make up the build margin do not have a single emissions factor, rather, the factor depends on the fuels actually used. However, in order to be further conservative, we have assumed that natural gas is used in all cases.

Actual generation is shown for each power plant for the period Sept. 2003 to Aug. 2004. The total generation for this period was 81,648 GWh. The % contribution of each of the power plants listed to this total are also shown in the table above. The power plants are listed in reverse chronological order of coming on line adding up to 34% of total generation.

The power plants Dock Sud (17%) and Puerto Nuevo (23%) bracket the methodology requirement to include 20% of the total generation.

The last column in the table shows the cumulative average emissions factor of power plants in reverse chronological order. The values corresponding to power plant including Dock Sud and Puerto Nuevo are 377.4 and 370.1 kg CO₂ per MWh. The average of these values is 373.7 kg CO₂/MWh.

Thus the build margin emissions factor for baseline power generation is **0.374 t CO₂/MWh**.

Step 3. Calculate the baseline emissions factor.

The consolidated methodology ACM0002 indicates that the emissions factor is a weighted average of the operating margin and the build margin, suggesting a 50/50 weighting.

One could argue that for generation, cogeneration or electricity end use efficiency at power levels small compared to installed capacity, a higher weighting should be given to the operating margin and a corresponding lower weighting to the build margin. In this case, however, there is hardly any difference between the operating margin (0.356 t CO₂/MWh) and the build margin (0.374 t CO₂/MWh). Thus we consider a 50/50 weighting rounding towards the operating margin, and we estimate the combined margin to be **0.365 tCO₂/MWh**.



Annex 4

MONITORING PLAN

Monitoring is required for the following purposes:

- To determine the *emissions factor for power generation* in order to determine the emissions offset by power generation in the project activity and sold through the power grid offsetting generation elsewhere.
- To determine *project emissions*, from fuel consumption at the project site, including that used for generating electricity sold through the power grid.
- To determine *baseline emissions* in a dynamic manner.
- To determine emissions reductions from estimates or project and (dynamic) baseline emissions.

The monitoring plan for each of these items is described below.

Emissions factor for grid-connected power generation

The monitoring requirements correspond to the Approved consolidated monitoring methodology ACM0002 “Consolidated monitoring methodology for zero-emissions grid-connected electricity generation from renewable sources.” Alternatively the small-scale methodology AMS I.D may be used, when electricity exports to the grid are below 15 MW.

ACM0002 refers to grid-connected renewable energy projects and requires the monitoring of:

- Electricity generation from the proposed project activity;
- Data needed to recalculate the operating margin emission factor, if needed, based on the choice of the method to determine the operating margin (OM), consistent with “Consolidated baseline methodology for grid-connected electricity generation from renewable sources” (ACM0002);
- Data needed to recalculate the build margin emission factor, if needed, consistent with “Consolidated baseline methodology for grid-connected electricity generation from renewable sources” (ACM0002);

This specific project involves cogeneration at a refinery, where a part of the electricity generated would meet local power requirements. Moreover, when the cogeneration equipment is under maintenance the refinery would need to purchase electricity from the power grid. Both power sales to the grid and power purchases from the grid would affect emissions elsewhere in the grid. Thus, both sales and purchases need to be monitored and net electricity sales (sale minus purchase) needs to be recorded.

Determining the operating margin emissions factor requires data on the generation of each power plant supplying the project power grid. These are divided into four categories: “zero price”, forced “S + T”, other forced, and dispatched (see Table 4.1 below). For each category, we obtain electricity generation and fuel consumption data from the national dispatch centre, CAMMESA. Emissions can be determined directly, based on the CO₂ emissions factors for the fuels involved, here coal, fuel oil, diesel, and natural gas. The Table 4.1 needs to be completed for each year of data for the monitoring period.

All except “dispatched” comprise low cost / must run power plants. Using the simple OM approach, the operating margin emissions factor for the year in question is given by the ratio of the total emissions from the “dispatched” power plants and the electricity generated by these power plants during the year.

**Table 4.1 Data table for determining operating margin emissions factor.**

Type of generation	Energy source	For each year of data		
		Generation (MWh)	Total fuel consumption	Emissions tCO ₂
Zero price	nuclear			0
	base hydro			0
	self/cogeneration natural gas			
Forced S+T	hydro			0
	fuel oil			
	natural gas			
	diesel			
Other forced	hydro			0
	coal			
	fuel oil			
	natural gas			
	diesel			
Dispatch	hydro			0
	coal			
	fuel oil			
	natural gas			
	diesel			
	TOTAL			

“S + T” refers to forced generation required for system and voltage stability.

“Other forced” refers to the following:

1. Equipment startup
2. Operating costs for start and stop, when it is cheaper to keep a generator operating
3. For downstream water requirements
4. For generator trials

Determining the build margin emissions factor requires similar data as above, except, in this case we also need the date each new power plant comes on line. We need to obtain date on the total generation of each of the new power plants until we reach 20% of the total generation for the year in question. The procedure described in the previous Annex will need to be repeated for each year of crediting period.

Once operating margin and build margin emissions factors have been determined, the combined margin emissions factor may be readily determined as the arithmetic mean of the two values, as was shown in Annex 3, for *ex-ante* determination of this emissions factor.



Project emissions

Ex-ante baseline and project emissions are determined from thermodynamic analysis, and reported in the PDD. Actual emissions are determined from monitored data. Project emissions are given by measurements of fuel consumption following project implementation.

Project emissions correspond to CO₂ emissions from fuel consumption within the project boundary. These emissions depend on the type and quantity of fuels used. The emissions factor for each fuel type (e.g. t CO₂/GJ) depends the carbon content of the fuel. These factors are determined from national data.

Fuel combustion also produces very small amounts of methane and nitrous oxide. Again emissions depend on type and quantity of fuels used, as well as the type of equipment involved. In this case, the emissions factors are based on IPCC reference values for equipment similar to those involved, since there are no national values available, and the overall emissions of these gases, in equivalent CO₂ terms is very small compared to the CO₂ emissions.

Monitoring thus involves recording the consumption of each fuel on a monthly basis, with periodic calibrations of measuring equipment involved. These are part of existing procedures at the Shell refinery for fuels used in the baseline and which would continue to be used following project implementation. The fuels are asphalt, fuel gas and fuel oil.

The project activity also requires natural gas to be purchased from the gas pipeline. In this case, the natural gas supplied to the project activity needs to be measured monthly using a calibrated flow meter following protocol and standards applicable to natural gas sale in the Argentina natural gas market, as specified by the National Regulatory Agency (ENARGAS).

For the determination of CO₂ emissions, the total consumption of each fuel on a monthly basis is sufficient. However, CH₄ and N₂O emissions can be equipment specific. Although these emissions are very small, if equipment specific fuel consumption data are available, also on a monthly basis, this would be preferable.

Baseline emissions (dynamic estimate)

Baseline emissions are determined in a dynamic manner from historical data and from measurements following project implementation through the following steps:

1. From historical data, determine the relationship between fuel input and total steam enthalpy output and total electric power output.
2. If more than one fuel type is used prior to project implementation, determine average ratio of fuel input of different fuels, again from historical data.
3. Following project implementation, determine total enthalpy value of steam produced by the cogeneration system from monitored data.
4. Using the historic relationship (step 1 above), determine baseline fuel consumption and electric power output corresponding to the measured data on steam output following project implementation. When more than one fuel is used prior to project implementation, determine consumption of each fuel using historical ratios of the different components (step 2 above). These are the values of BFC_i .
5. From the step 4 estimate of electric power output and monitored power demand of industry, determine net purchase of electricity from the grid in baseline, $NBEP$.
6. From monitored data of electricity sold through the interconnected grid following project implementation, determine electricity sale through the grid, $NPES$.



7. Use Eq. (D.2) to calculate baseline emissions using BFC_i from Step 4, $NBEP$ from Step 5, and $NPES$ from Step 6.

The procedure for calculating *ex-post* baseline emissions is described in Section D.2.1.4 of the PDD.

Steps 1 and 2 depend on historical data, and the parameters determined from data from 2000-02 are as follows:

σ_{elect}	is the BRPS specific electricity generation per unit of steam delivered to refinery	= 0.0261 MWh / GJ of steam enthalpy
λ_{FC}	is the BRPS specific fuel consumption per unit of steam delivered to refinery	= 0.0261 ton SRF / GJ of total steam enthalpy

The proportion of different fuels in the five year period 1998-2002 gives the following values of the fraction f of different fuels used in the baseline to make up the total fuel consumption:

$$f_{asphalt} = \frac{FC_{asphalt}}{FC_{asphalt} + FC_{fuel_gas} + FC_{fueloil}} = 0.770$$

$$f_{fuel_gas} = \frac{FC_{fuel_gas}}{FC_{asphalt} + FC_{fuel_gas} + FC_{fueloil}} = 0.167$$

$$f_{fuel_oil} = \frac{FC_{fuel_oil}}{FC_{asphalt} + FC_{fuel_gas} + FC_{fueloil}} = 0.063$$

These values are derived from past data in the sheet “consumption profile” of the attached Excel file: [Shell_MGM_MVP_ER.xls](#).

This same spreadsheet comprises a data entry sheet “Fuel Consumption”, where monthly consumption of each fuel is recorded. These data are necessary to determine on-site emissions. The same sheet also includes spaces for entering refinery power demand, and electricity sold through the grid from the boiler room / power station. Once a full year of data are entered in this sheet, other sheets automatically calculate project emissions, dynamic baseline emissions, and emissions. The only other parameter to be entered by the project sponsor during project monitoring is the emissions factor for the power grid, in the beige cells of sheet “Electricity-BS.” A value of 365 kg CO₂ per MWh, as determined in Annex 3 has been included in the spreadsheet for now. This value will need to be updated annually, as monitoring proceeds.

Emissions reductions

Once the emissions factor for grid-connected electricity generation has been determined, and project and baseline emissions have been calculated, emissions reductions can be readily determined.

The last sheet of [Shell_MGM_MVP_ER.xls](#) would present summary data on annual baseline emissions (calculated in a dynamic manner), annual project emissions, and emissions reductions, all of which would be automatically calculated. - - - -