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

CONTENTS

Annexes

SECTION A. General description of project activity

A.1. Title of the project activity:

>>
Combined Cycle at Loma de la Lata Thermo Unit Project
PDD Version Number 05
24/07/2012

A.2. Description of the project activity:

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The Combined Cycle at Loma de la Lata Thermo Unit Project (hereafter, the "Project") developed by Central Térmica Loma de la Lata S.A. (hereafter referred to as the "Project Developer") is a conversion of an existing single cycle generation plant into a combined cycle plant at the "Central Térmica Loma de la Lata", located in Neuquén Province in Argentina. The Project Developer is a subsidiary of Pampa Energía S.A., the largest integrated electricity company in Argentina.

As per the definition of the ACM0007 (Version 06.1.0), Central Térmica Loma de la Lata is a single cycle thermal plant consisting of three natural gas turbines. Its gross installed capacity is 369.93 MW, representing approximately, as of the starting date of the Project activity, 1.5% of the installed capacity in Argentina (the total installed capacity of power units belonging to the wholesale electricity market was 24,092 MW in 2006[1]). This thermal plant enjoys a privileged location as it does not require the use of the Argentine gas transportation infrastructure due to its proximity to the regional gas fields.

The scenario existing prior to the start of implementation of the proposed Project activity, corresponding to the baseline, is the operation of the single cycle thermal plant at Loma de la Lata and grid electricity generation to supply the same demand that will be met by the proposed Project activity.

The Project activity consists of the conversion of the existing plant into a combined cycle generation plant by adding three Heat Recovery Steam Generators (HRSGs) that will capture the heat from the exhaust gases released to the atmosphere by the three gas turbines and use it to produce steam. The steam produced in the HRSGs will be used to drive a 175.73 MW gross capacity steam turbine.

Therefore, the Project will increase the supply of electricity to the Argentina's national grid, displacing energy generated by fossil fuel plants, and thereby meeting the energy needs of the country with a cleaner source of energy. In this way, GHG emissions will be reduced with respect to those occurring with the operation of the single cycle configuration.

The Project is helping Argentina fulfil its goals of promoting sustainable development. Specifically, by:

- Using cleaner and efficient technologies, conserving natural resources and increasing the security of the electricity supply;
- Contributing to technology transfer, since the most important parts of the technology —turbo-generator, HRSGs, condenser, cooling tower and engineering— comes mainly from developed

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[1] Statistical Report of the Electricity Sector 2006, Part 2, Argentina Secretariat of Energy, Ministry of Federal Planning, Public Investment and Services; http://energia3.mecon.gov.ar/contenidos/verpagina.php?idpagina=2599.

countries —Sweden (turbine), Germany (generator), USA (HRSGs) and Spain (condenser, cooling tower and engineering)— consolidating the technology in the host country;

- Contributing to the development of technological capacity since the technical maintenance will be done by local labour provided within Argentina.

A.3. Project participants:

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Name of party involved (*) ((host) indicates a host party)	Private and/or public entity(ies) Project participants (*) (as applicable)	Kindly indicate if the party involved wishes to be considered as project participant (Yes/No)
Argentina (host)	Central Térmica Loma de la Lata S.A.	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 requesting registration, the approval by the Party(ies) involved is required.

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

A.4.1.1. Host Party(ies):

Argentina

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

Neuquén Province

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

Department of Confluencia

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

The Project is located in Neuquén Province, Department of Confluencia, Provincial Road 51, km 85, Portezuelo Grande. The geographical coordinates are given by:

Entrance of the plant: 38.5144000° S, 68.6052028° W
Gas turbine 1: 38.5132306° S, 68.6063056° W
Gas turbine 2: 38.5127778° S, 68.6062944° W
Gas turbine 3: 38.5123194° S, 68.6062167° W
Steam turbine: 38.5119861° S, 68.6062083° W

Figure 1 shows the location of the proposed Project activity.

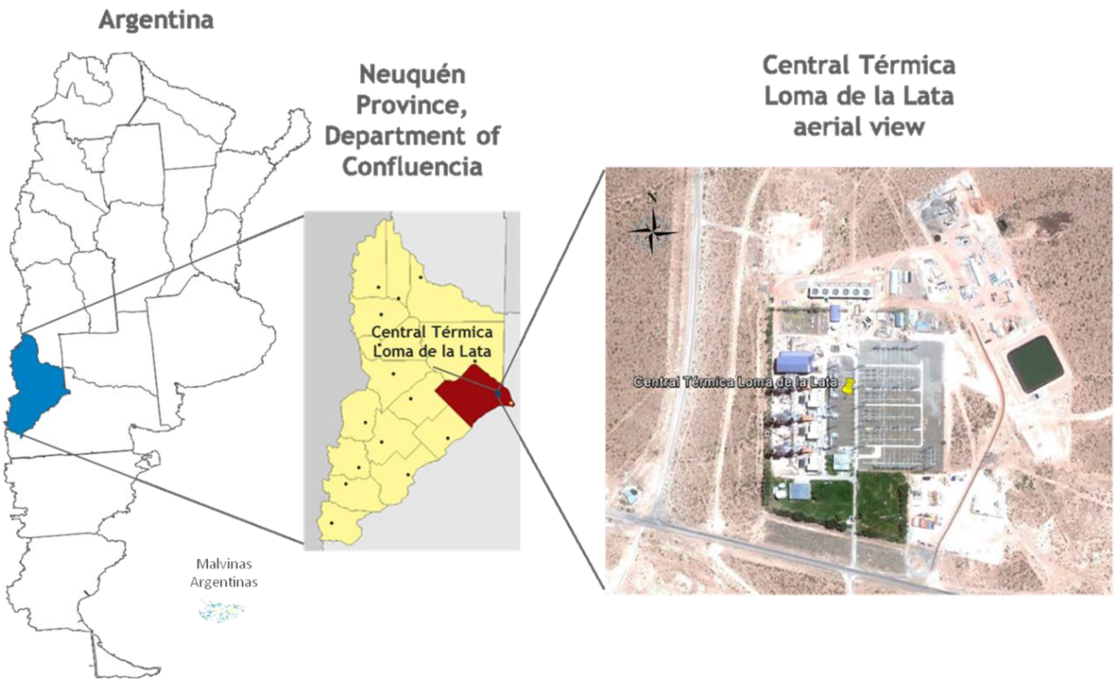


Figure 1: Project location

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

According to Annex A of the Kyoto Protocol, the Project falls under UNFCCC Sectoral Scope 1: Energy Industries (renewable / non-renewable sources).

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

The existing plant, operational since 1994, consists of three identical General Electric natural gas turbines operating in a single cycle. The characteristics of the turbines are:

Single cycle	
Brand	GE
Model	Frame-9E (PG9171E)
Output (MW)	123.31
Number of units	3
Heat Rate ISO (kJ/kWh)	10,676

The Project consists of the conversion of the existing single cycle plant into a combined cycle power plant.

In a Combined Cycle Gas Turbine ("CCGT") plant, a gas turbine plant is combined with a steam turbine generator to produce electricity from the previously-unused hot (500°C or more) waste gases from the gas turbines. These gases are captured and passed through a HRSG to create steam. This steam is then passed through a steam turbine to create additional electricity. Therefore, upgrading a single cycle plant to a combined cycle greatly increases the plant's efficiency and its installed capacity.

The Project activity includes the installation of a new steam turbogenerator with a gross capacity of 175.73 MW and its related equipment. The most important parts of the technology (turbo-generator and HRSGs) come mainly from developed countries such as Sweden (turbine), Germany (generator) and USA (HRSG).

The layout is based on a configuration "3+3+1", meaning that based on the three existing gas turbo-generators, three HRSGs and one steam turbine will be incorporated. The inclusion of gas by-pass systems between the gas turbines and the HRSG, and a steam by-pass system for the steam turbine will provide high operation flexibility due to the possibility to operate with multiples configurations, i.e. 3+3+1, 2+2+1 or 1+1+1.

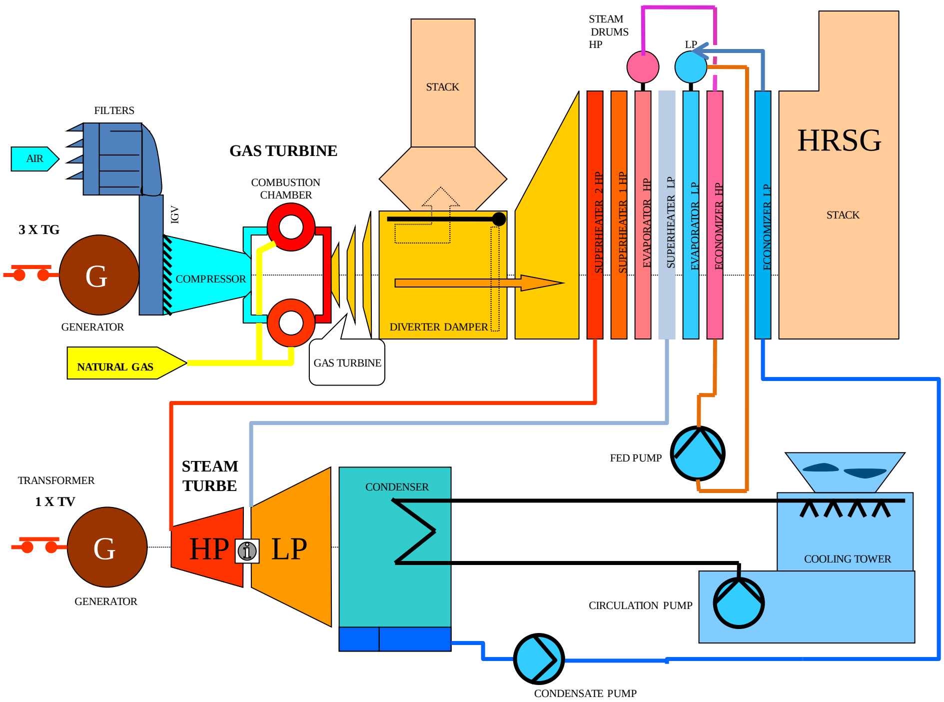
A detailed description of the equipments is presented below:

1. *Recovery Boiler or Heat Recovery Steam Generator (HRSGs), one per gas turbine:* this equipment utilizes the waste heat of the hot exhaust gases from the gas turbines to generate steam. The boilers have evaporators of high and low pressures in order to maximize the heat recovery of the waste gases of the boiler, thus, increasing its performance.

2. *Steam turbine (ST) and Generator:* A single Siemens condensing non-reheat steam turbine, Model SST-900-C with 175.73 MW of installed capacity, will receive the high pressure steam and expand it producing work that will be converted into electric energy by the generator.

Steam turbine	
Brand	Siemens
Model	SST-900-C
Power output ISO (MW)	175.73
Generator	
Brand	Siemens
Model	SGen5-100A-2P 115-36
Rating (MVA)	223.5
Power Factor (lagging)	0.85
Voltage (kV)	15.75 +/- 5%
Frequency (Hz)	50 +/- 2%

3. *Condenser and water cooling system:* The water cooler condenser is designed to condensate the steam from the turbine operating in maximum charge conditions and in by-pass conditions. The water from the condenser is cooled in the cooling tower. The water cooling system takes water for the open cooling system from a nearby lake and returns the water into the same lake, after the appropriate processing.



The baseline scenario corresponds to the continuation of the operation of the single cycle power plant and the grid electricity generation according to the combined margin approach. Emissions associated to the same types and levels of services provided by the power units in the combined cycle configuration that would have been provided in the baseline are those corresponding to CO_2 emissions from fossil fuel fired power plants connected to the same electricity system as the Project power units and CO_2 emissions from operation of the Project power units in single cycle mode.

On the other hand, according to the methodology Project emissions are given by CO_2 emissions from on-site consumption of fossil fuels to operate the Project power units and CO_2 emissions from on-site

consumption of fossil fuels, to supplement the exhaust heat used to operate the steam turbine. The last source is not applicable to the proposed Project activity since there is no supplemental firing.

The load factor of the single cycle has been 38.2% on average according to historical records from 2005 to 2010 while the effective load factor of the combined cycle is expected to be 86.9% according to Mercados Energéticos Consultores (consultancy firm that developed the electricity market studies). The Project will also increase the thermal efficiency of the power plant from 34% (historical records) to approximately 49%.

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

Table 1: Estimated Amount of Emission Reductions

Years	**Annual estimation of emissions reductions in tonnes of CO_2e**
1 September – 31 December 2012	217,798
2013	651,610
2014	651,610
2015	651,610
2016	651,610
2017	651,610
2018	651,610
1 January – 31 August 2019	433,812
Total estimated reductions (tonnes of CO2e)	**4.561.270**
Total number of crediting years	**7**
Annual average over the crediting period of estimated reductions (tonnes of CO_2e)	**651,610**

A.4.5. Public funding of the Project activity:

The Project will not receive any public funding from Parties included in Annex I of the UNFCCC.

SECTION B. Application of a baseline and monitoring methodology

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

The Project uses the approved consolidated baseline methodology ACM0007 (Approved consolidated baseline and monitoring methodology for conversion from single cycle to combined cycle power generation), Version 06.1.0, approved in EB68.

The additionality of the Project activity is demonstrated and assessed using the “Combined tool to identify the baseline scenario and demonstrate additionality”, Version 04.0.0.

The "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion", Version 02, is utilized to calculate the Project activity emissions.

The "Tool to calculate the emission factor for an electricity system", Version 02.2.1, is utilized to determine the Argentine grid emission factor.

The "Tool to determine the remaining lifetime of equipment", Version 01, is used to show that the Project activity does not increase the lifetime of the existing gas turbines during the crediting period.

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

The Project meets all the applicability criteria as set out in the methodology and outlined in the table 2:

Table 2: ACM0007 applicability conditions

Conditions	Yes/No	Justification/Explanation
The methodology applies to project activities that convert one or several grid connected power units at one site from single-cycle to combined-cycle mode.	Yes	The proposed project activity consists of the conversion of three grid connected power units at Loma de la Lata site from single-cycle to a combined-cycle mode.
The unit(s) have an operational history of at least one year with no major retrofit, and at least one unit has an operational history of more than three years with no major retrofit. There is no major retrofit in these time periods.	Yes	The three natural gas turbines of the single cycle power plant started to operate in 1994. They did not suffer any major retrofit since the operation start date.
In the case that a unit has less than three years of operational history: all project power unit(s) were designed and commissioned for operation in single cycle mode only.	Not applicable	The three natural gas turbines were commissioned in 1994 to operate in single cycle mode only.
During the most recent three years prior to the implementation of the project activity and during the crediting period the project power unit(s) use(d) only the following fuel types: (a) Fossil fuels; and/or (b) Blends of fossil fuels and biofuels, where the biofuel is	Yes	Since the single cycle started to operate in 1994 it only used fossil fuel (particularly natural gas) and will continue utilizing only fossil fuel during the Project crediting period.

Conditions	Yes/No	Justification/Explanation
blended to the fossil fuel in a situation that is outside the control of the project participants (such as regulatory requirements to blend biodiesel with diesel or biogas with natural gas). Note that this methodology does not allow crediting for an increase in the share of biofuels.		
The type(s) of fossil fuels used by the project power unit(s) during the crediting period were also used during the most recent three years prior to the implementation of the project activity, except, where applicable, any auxiliary fuel consumption (e.g. for start-ups) which shall not exceed 3% of the total fuel consumption in the unit(s) (measured on an energy basis).	Yes	The Project power units will utilize natural gas during the crediting period, the same fuel that was also used during the most recent three years prior to the implementation of the Project activity.
The Project activity does not increase the lifetime of the existing gas turbine or engine during the crediting period (i.e. this methodology is applicable up to the end of the lifetime of existing gas turbine or engine, if shorter than crediting period).	Yes	The existing gas turbines were installed in May 1994. Up to November 1, 2011, gas turbine number three is the one that has operated more time (73,017 hours). According with General Electric[2] (Loma de la Lata single cycle gas turbines provider), an area for attention, although a longer-term concern, is the life of the compressor and turbine rotors. Disassembly and inspection of all rotor components is required when the accumulated rotor starts or hours reach the inspection limit. When no recommendations have been made, rotor inspection should be performed at 5,000 factored starts or 200,000 factored hours. This interval indicates the serviceable life of the rotor and is generally considered to be the teardown inspection and repair/replacement interval for the rotor. According with the historical operation of Loma de la Lata single cycle and the expected operation in combined cycle, the limited factor for the rotor inspection is the

[2] GE Energy, "Heavy-Duty Gas Turbine Operating and Maintenance Considerations" (2004). Manufacturer's information of the technical lifetime of equipment compared to the data of first commissioning is in agreement with option (a) of the methodological procedure of the "Tool to determine the remaining lifetime of equipment", version 01.

Conditions	Yes/No	Justification/Explanation
		factored hours (200,000). According with the above mentioned, the remaining lifetime of the gas turbines rotors would be at least 126,983 operative hours (38 years). In case a retrofit is needed (e.g. rotor), it will be part of standard maintenance practices to keep gas turbines in operation (take into account that the oldest units still in operation in the national grid are from the 60s[3]). The Project activity will increase the load factor of the gas turbines, thus reducing rather than enlarging the time between major maintenance. Therefore, the Project activity will utilise the exhaust heat of the existing gas turbines but it will not involve any upgrade or modification of the gas turbines themselves as a consequence of the Project activity and it will not increase their lifetime.

The Project activity meets all the conditions above and therefore the methodology is applicable to the proposed Project activity.

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

According to ACM0007 methodology, the spatial extent of the Project boundary includes the Project power units and all power plants connected to the same grid electricity system.

For the purpose of determining GHG emissions of the Project activity, the following emission source was included:

- CO_2 emissions from on-site fuel consumption of fossil fuels for operation of the gas turbine or engine.
- CO_2 emissions from Diesel oil consumption corresponding to emergency equipment of the steam turbine (Generation set GE SSAA TV 360 kVA).

To operate the steam turbine, no additional consumption of fuel to supplement the waste heat generated from the gas turbine or engine is required. Therefore, this source of emissions is not applicable to the present Project activity.

For the purpose of determining the baseline, the following emission sources were included:

- CO_2 emissions from fossil fuel fired power plants connected to the same grid electricity system as the Project power units; and
- CO_2 emissions from operation of the Project power units in single cycle mode.

[3] There are gas turbines since 1964 working in single cycle at the Sarmiento de Cuyo power plant.

During its condition as open cycle power plant, in an event of blackout said plant had the following emergency power supply options:

- 500 kV high voltage transmission line
- Emergency generation set GDE 800 kVA
- 33 kV medium voltage transmission line of EPEN

The abovementioned power resources remain available for Combined Cycle mode. Thus, the eventual consumption from these emergency power supply options are not considered for emissions monitoring since they would have taken place in baseline scenario as well as in Project scenario.

The spatial extent of the Project electricity system, including issues related to the calculation of the build margin (BM) and operating margin (OM), as defined in the "Tool to calculate the emission factor for an electricity system", Version 02.2.1, encompasses the Loma de la Lata thermoelectric plant and all plants connected to the Argentine National Grid System.

Table 3 illustrates the emissions sources included in or excluded from the Project boundary:

Table 3: Emission sources

	Source	Gas	Included?	Justification/Explanation
Baseline Scenario	Grid electricity generation	CO_2	Yes	Main emission source.
		CH_4	No	Excluded for simplification. This is conservative.
		N_2O	No	Excluded for simplification. This is conservative.
	On-site fossil fuel consumption to operate the project power units in single cycle mode.	CO_2	Yes	An important emission source.
		CH_4	No	Excluded for simplification. This emission source is assumed to be very small.
		N_2O	No	Excluded for simplification. This emission source is assumed to be very small.
Project activity	On-site fossil fuel consumption to operate the project power units in combined cycle mode.	CO_2	Yes	An important emission source.
		CH_4	No	Excluded for simplification. This emission source is assumed to be very small.
		N_2O	No	Excluded for simplification. This emission source is assumed to be very small.
	On-site fossil fuel consumption to supplement the exhaust heat in operating the steam turbine.	CO_2	Yes	May be an important emission source (not in the case of the proposed Project activity).
		CH_4	No	Excluded for simplification. This emission source is assumed to be very small.
		N_2O	No	Excluded for simplification. This emission source is assumed to be very small.

	Diesel oil consumption corresponding to emergency equipment of the steam turbine.	CO_2	Yes	An eventual emission source.
		CH_4	No	Excluded for simplification. This emission source is assumed to be very small.
		N_2O	No	Excluded for simplification. This emission source is assumed to be very small.

Leakage is given by emissions associated with the upstream emissions of an increase in fossil fuel (natural gas) use in the Project activity. There are no emissions associated with a change in the amount of exhaust heat recovery due to the project activity.

The present Project activity will not consume on-site fossil fuel to supplement the exhaust heat to operate the steam turbine. Therefore, this source is not included in Figure 2, which shows the Project boundary:

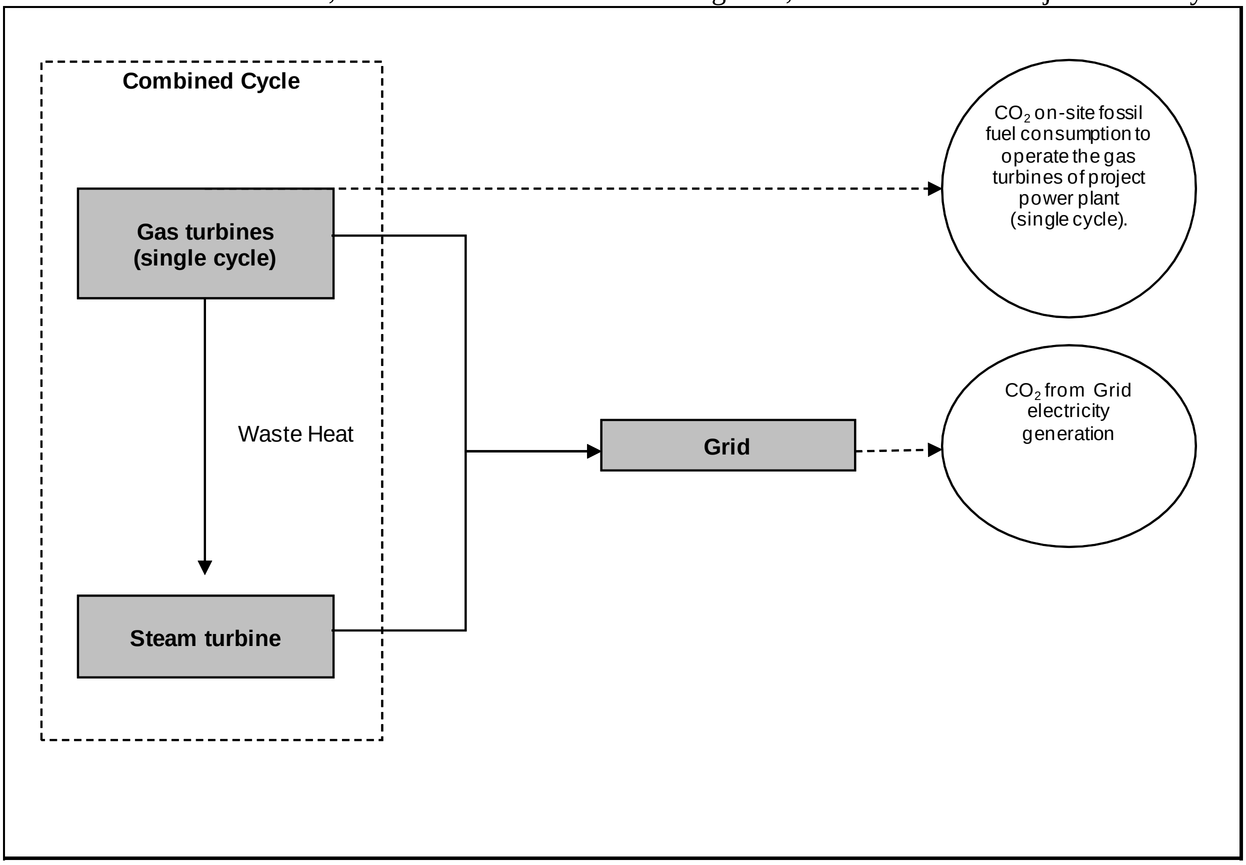


Figure 2: Project boundary

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

According to the Baseline Methodology for conversion from single cycle to combined cycle power generation ACM0007, Version 06.1.0, the Project participants shall identify the most plausible baseline

scenario and demonstrate additionality using the latest approved version of the "Combined tool to identify the baseline scenario and demonstrate additionality", Version 04.0.0.

Attending to the ACM0007 baseline methodology requirements, that all plausible alternative options to the Project activity should be identified and a detailed analysis should be performed on each option according to the steps highlighted in the "Combined Tool to identify the baseline scenario and demonstrate additionality", version 04.0.0, the baseline alternatives are assessed below.

Step 0: Demonstration whether the proposed project activity is the First-of-its-kind

This optional step is not taken into account.

Step 1: Identification of alternative scenarios

Step 1a: Define alternative scenarios to the proposed CDM project activity

Alternative scenarios that (a) are available to the project participant, (b) cannot be implemented in parallel to the proposed project activity, and (c) provide outputs or services with comparable quality, properties and application areas as the proposed CDM project activity are identified under this sub-step.

The relevant geographical area is the Host Country (Argentina), since the Project is connected to the National Interconnected System (SADI – *Sistema Argentino de Interconexión*).

In accordance with ACM0007, Version 06.1.0, the three alternatives that should be considered are:

1. *Proposed project activity undertaken without being registered as a CDM project activity*:

   Under this scenario the Project Developer would commission three waste heat recovery boilers and a steam turbine of the same capacity as the Project activity to operate in a combined cycle configuration, without the support of the CDM.

2. *Continuation of the current practice (to not implement the project activity)*:

   Under this scenario power to meet the grid demand is generated and supplied by the existing gas turbines at the site running in single cycle configuration.

3. *If applicable, the proposed project activity undertaken without being registered as a CDM project activity undertaken at a later point in time*:

   This alternative is dismissed since, neither at the time of the start date of the Project activity nor today, there are no relevant expected regulatory changes (see the barrier analysis below), or technical and operational changes such as achieving the end-of-life of existing equipment (see section B.2) that could incentivise and/or facilitate the development of the proposed Project activity at a later point in time.

Other plausible alternatives to be considered include:

4. *Investment in a new fossil fuel plant of annual output equivalent to the proposed Project*:

Under this scenario the Project developer would invest in new fossil fuel turbines with an equivalent electricity generation to the proposed project activity in order to increase the power generation of Loma de la Lata single cycle power plant.

Regarding plausible fossil fuels to be used, the penetration of natural gas since the 1970 decade has mainly displaced the consumption of oil products as the preferred choice for new generation projects as the Argentine electricity generation sector[4] has an economic dispatch, limiting the dispatch of liquid fuel units only for short periods of peak demand. In 2006, the installed capacity and electricity generation of diesel power plants only represented 1.5% and 0.2% of the total installed capacity and electricity generation in the country, respectively (1.6% and 0.3%, respectively in 2007).[5] Additionally, the participation of coal in power generation is negligible (1.6% on average between 2000 and 2006). Storage capacity for liquid fuels at generation facilities is limited, increasing the structural cost of using these types of fuels. Therefore, the only plausible fossil fuel to be used is new natural gas.

The required installed capacity of a new natural gas plant operating at the historical load factor of the single cycle (38.2%) and with an annual output equivalent to the proposed Project activity (2,763,175 MWh) should be 826 MW, which corresponds to six GE's FRAME-9 units (the same technology existing at Loma de la Lata). An investment on a new fossil fuel plant as the one described in this scenario would not be considered a rational alternative. On one hand, a new natural gas single cycle unit at the same location of the Project activity will face higher uncertainties to secure the firm supply of a larger volume of additional natural gas. Considering an annual output equivalent to the proposed Project activity (2,763,175 MWh) and a net heat rate (LHV) of 2,550 kcal/kWh[6] (using the same technology existing at Loma de la Lata for the plant expansion, GE's FRAME-9) the increase in natural gas consumption would be 792 million m^3 compared to 468 million m^3 for the Project activity (69% higher). This dependence on higher natural gas volumes involves uncertainties related to the access to larger incremental amounts of natural gas under a context of limited supply of gas or increased price of gas for new open-cycle gas-fired plants (as a consequence of (i) the need to import larger gas volumes at a price higher than the local supply as a result of the reduction in domestic production and (ii) the redirecting of gas to attend specific demands, such as household gas consumers and the thermal power plants supplying residential electricity consumers).

On the other hand, and more relevant to the rational investor's decision, the low efficiency of the single cycle leads to a high operation cost declared to CAMMESA with the consequence of it being historically dispatched only with a 38.2% load factor. The low efficiency of the single cycle was the cause that, at the time of the start date of the Project activity, there was more than

[4] Argentinean National Greenhouse Gases Inventory 2000, Volume II; Page 163. Available at: http://aplicaciones.medioambiente.gov.ar/archivos/web/UCC/File/comunicaciones_nacionales/parte2_inventario_gases.pdf.

[5] Statistical Report of the Electricity Sector 2006, Part 2, and Statistical Report of the Electricity Sector 2007, Part 2, National Secretariat of Energy. Available at: http://energia3.mecon.gov.ar/contenidos/verpagina.php?idpagina=2599.

[6] GE Warrant, FRAME-9, Loma de la Lata, 1994.

50% of the available installed capacity that was unused. Thus, it would be more logical for the Project developer first to have the current capacity operating at full load factor taking advantage of the idle capacity rather than installing additional capacity that would be in direct competition with the existing units. In addition this alternative scenario would face similar institutional and investment barriers presented by scenario 1 as shown in the barrier analysis below.

Therefore, this alternative scenario cannot be considered as a plausible baseline scenario.

5. *Commercial renewable power plant of equivalent capacity to the proposed Project*:

   This alternative refers mainly to a hydropower plant of equivalent output since it is the only renewable technology to be firmly established in the Argentine power sector, representing 34.8% of the total installed capacity within the country in 2006. According to the National Secretariat of Energy, the potential of wind energy and photovoltaic resources still needs to be inventoried.[7] No solar and wind power plants were delivering electricity to the MEM (Wholesale Electricity Market) in 2006 nor in 2007. The few cases corresponded to isolated systems or power plants connected to the SADI but not participating in the MEM.

Hence out of the 5 scenarios identified only the following three alternatives scenarios of the Project activity can be considered and will be further assessed in step 1b:

1. *Proposed project activity undertaken without being registered as a CDM project activity*
2. *Continuation of the current practice (to not implement the project activity)*
5. *Commercial renewable power plant of equivalent capacity to the proposed Project*

Step 1b: Consistency with mandatory applicable laws and regulations

This step consists in evaluating if the alternative scenarios are in compliance with all applicable legal requirements.

Laws Nº 15,336 and Nº 24,065 establish the legal framework of the energy industry in Argentina. The implementation of such framework required the enactment of various decrees and other legislative measures by the Executive, such as, resolutions and notes of the Secretariat of Energy.[8]

According to section 35 of Law N° 24,065, the Secretariat of Energy approved the Resolution N° 61/92. Such resolution and its modifications are compiled by CAMMESA in an unofficial document known as "The Procedures" (Los Procedimientos).[9]

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[7] Nowadays situation, National Secretariat of Energy. Available at: http://energia3.mecon.gov.ar/contenidos/archivos/Reorganizacion/renovables/energias_renovables.pdf.

[8] National Secretariat of Energy, Legal Framework: http://energia3.mecon.gov.ar/contenidos/verpagina.php?idpagina=882.

[9] "Los Procedimientos" CAMMESA: http://portalweb.cammesa.com/Pages/Institucional/Empresa/procedimientos.aspx.

On the other hand, the environmental legal framework includes national and local laws and regulations. According to the Argentine Constitution the powers to regulate environmental issues are coordinated between all the levels of government, including the municipalities, the provinces, the city of Buenos Aires and the federal government. It must be noted the participation of the "Federal Environmental Council" (Consejo Federal de Medio Ambiente, COFEMA; Law Nº 25,675[10] - General Environmental Policy) as an inter-jurisdictional agency competent in environmental issues.

Finally it must be taken into account that:

- There is no regulation in place that requires the utilisation of waste heat on the premises where it is generated.
- There is no regulation in place on energy efficiency for power projects; and
- Emission norms for power projects. Secretariat of Energy Resolution 182/95 establishes a system of record and control of emission and the strict fulfilment of the environmental legislation.[11] In the case of electric power generation of thermal origin, the Resolution Nº 182/95[12] of the Secretariat of Energy is applicable for emission limits and Resolutions Nº 881/99 and Nº 371/00[13] of the National Electricity Regulation Entity (ENRE). Moreover, Resolution 555/01 of ENRE establishes the implementation of an environmental management system.

1. *Project activity implemented as a non-CDM Project*:

   This activity fulfils all applicable legal requirements and regulations. As noted before, there is no regulation in place that requires the utilisation of waste heat on the premises where it is generated. Hence, neither there is regulation enforcing that the waste heat shall be used in Argentina, nor there is prevention to this opportunity to be adopted by the project participant.

2. *Continuation of current practice*:

   The operation of the power generation plant in a single cycle configuration fulfils all applicable legal requirements and regulations. There is no regulation in Argentina to prevent the operation of a single cycle and there are no specific laws that require upgrading existing single cycle thermal plants to operate in combined cycle or to utilise waste heat.

5. *Renewable energy generation plant (mainly hydro) of equivalent capacity to the proposed Project*:

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[10] Law 25,675: http://www.infoleg.gov.ar/infolegInternet/anexos/75000-79999/79980/norma.htm.

[11] Resolution SE 182/95: http://energia3.mecon.gov.ar/contenidos/verpagina.php?idpagina=889.

[12] Resolution SE 0182/1995. "Boletín Oficial" N° 28.153, 30 May 1995, p. 2.

[13] Resolution ENRE 881/99:
http://www.enre.gov.ar/web/bibliotd.nsf/cccc1c4bbfc83d5703256759004c597b/e9b486d6598f5a02032567bd0054b486?OpenDocument.

Resolution ENRE 371/00:
http://www.enre.gov.ar/web/bibliotd.nsf/9729cc8384333c0603256926005bc2c1/01af0b5a80262d110325691400490dbe?OpenDocument.

It is possible to invest in a renewable energy generation plant upon fulfilment of all applicable legal requirements and regulations, including but not limited to environmental local regulations, "The Procedures" and any other federal regulation regarding to the connection to the National Interconnected System, which are common to any generation project and those related to the generation of renewable energy.

In this specific case, according to Law Nº 15,336,[14] it is necessary to obtain a concession from the Executive Power that enables the generation of hydroelectric energy. Moreover, in the Province of Neuquén, according to the Water Code (Provincial Law Nº 899 and regulation Decree Nº 1,514/09), it is necessary to obtain a permission or concession for the use of water for energy generation.

Therefore, none of the plausible alternatives are prevented due to regulation compliance. All the scenarios pass to the next step.

Step 2: Barrier analysis

This step serves to identify barriers and to assess which alternative scenarios are prevented by these barriers by applying the following sub-steps:

Step 2a: Identify barriers that would prevent the implementation of alternative scenarios

The two major barriers, identified and described below, would prevent the implementation of alternative scenarios taking into account that the combination of these barrier conditions cannot be easily translated into monetary terms but can be easily understood by business decision makers as being a high perceived risks that prevents new investment to be implemented. The grouping of such barriers can be featured as regulatory unpredictability in the sector and a deteriorating investment climate in the host country:

- Institutional barrier – This barrier is associated to Argentina's energy policy framework, taking into consideration the real and perceived risks and the overall economic framework presented by the electricity sector in the host country. It analyses the lack of institutional stability, which is a requirement that has to be met before considering the possibility of undertaking any of the scenarios.

- Investment barriers – This barrier evaluates the risks associated with the establishment of new investments to each scenario, considering the overall economics of the energy sector prevailing in the host country and the conditions and financing availability for similar activities. As is the case with the institutional barrier above, the impact of the existence of the type of barriers analysed would be sufficient to prevent a new investment decision in the host country, prior to a financial analysis in the case it could be done.

Step 2b: Eliminate alternative scenarios which are prevented by the identified barriers

- ***Institutional barrier***

1. *Project activity implemented as a non-CDM Project*:

[14] http://mepriv.mecon.gov.ar/Normas/15336-60.htm.

Alternative 1 faces significant institutional barriers as changes in Argentina's energy policy framework, introduced as a consequence of the crisis of 2001/2002, negatively affected the electricity sector preventing new investments in generation to be implemented.

Until 1991 almost all the Argentine electricity sector was controlled by the National Government. However, in 1992 the government decided to deregulate the electricity industry[15], including the power generation, distribution and transportation activities, giving place to the privatization of many power companies while at the same time it also set the conditions to motivate the private sector to invest in the expansion of the electricity installed capacity. As an example, from 1992 to 2001, generation installed capacity increased by 68%, growing from 13,328 MW in 1992[16] to 22,344 MW in 2001[17]. The main objective of the privatization law approved in 1992 (Law 24,065[15]) was to promote private investment, the modernization of the electricity sector and to improve the service quality and efficiency. In doing so, it created new market conditions focusing on the free competition by current and new market participants. The law also created the Wholesale Electricity Market Administrator, establishing CAMMESA[18] (a company with participation of the Secretariat of Energy[19] and associations representing power generators, transporters, distributors and large users) as the responsible of managing the National electricity market. As a consequence of the electricity market deregulation, many investors entered this market including foreign investors such as ENDESA (Spain), DUKE (USA) and EDF (France), among others.

However, during 2001 and 2002 Argentina experienced a period of serious political crisis, impacting negatively on its economic and social development and the electricity sector in particular. For example, a 'pesification' program was implemented affecting the electricity prices because (a) the government converted electricity tariffs from US dollars to Argentine pesos regardless of whether electricity companies or new electricity projects had their costs, capital investments or debt denominated in US dollars, and (b) the convertibility law that had fixed the exchange rate at AR$ 1 (one Argentine peso) = US$ 1 (one US dollar) was derogated in 2002 and therefore the Argentine peso highly devaluated, reaching in few months an exchange rate of 3.90 AR$/US$ (June 25th, 2002)[20 21 22].

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[15] http://www.infoleg.gov.ar/infolegInternet/anexos/0-4999/464/norma.htm.

[16] National Electricity Regulator's 1997 Annual Report (ENRE), chapter 1: the Wholesale Electricity Market (El Mercado Eléctrico Mayorista (MEM) in Spanish). Available at http://www.enre.gov.ar/web/web.nsf/Files/97p01.pdf/$FILE/97p01.pdf

[17] Argentina's Wholesale Electricity Market Annual Report, CAMMESA, 2001. Available at http://portalweb.cammesa.com/memnet1/Pages/descargas.aspx.

[18] http://portalweb.cammesa.com/Pages/Institucional/defaultinstitucional.aspx.

[19] http://energia3.mecon.gov.ar/home/.

[20] Data obtained from Argentina's Central Bank, available at http://www.bcra.gov.ar/.

[21] Law 25,561 of January 6, 2002, derogated the convertibility law that fixed one Argentine peso to one US dollar and converted tariffs to Argentine pesos: http://infoleg.mecon.gov.ar/infolegInternet/anexos/70000-74999/71477/norma.htm.

The government also implemented several changes to the regulatory framework governing the Wholesale Electricity Market (MEM)[23]. These regulatory changes were intended to control prices in the spot market, in order to avoid an increase of electricity prices to end-users.

The main changes affecting the profitability of electricity companies were[23] (a) the way the spot price of electricity was calculated, which used to be set as the marginal cost of electricity, was changed to a system where the marginal cost is determined assuming the availability, at regulated prices, of natural gas for thermal units, regardless of the actual fuel used to generate, therefore artificially lowering the spot price in cases where the marginal unit consumed, for example, fuel oil or diesel oil (Resolution SE 240/2003), (b) the maximum electricity tariff (spot price) that could be received by generation companies was capped at 120 AR$/MWh (Resolution SE 240/2003), (c) electricity generation companies would no longer collect in cash their profit (the difference between their costs and the spot price mentioned above) but instead they began to accrue credits with undefined maturity against CAMMESA and to collect only their variable costs (Resolutions SE 406/2003 and SE 943/2003), and (d) payment for capacity availability, which is intended to remunerate capital investment, and which was set at 10 US$/MW-Hrp prior to 2002, was converted to Argentine pesos and set fixed at 12 AR$/MW-Hrp (Resolution SE 317/2002). Measured in US dollars at the exchange rate of 3.90 AR$/US$, this represented a 69% reduction compared to the 2001 value.

This situation was further affected by the high inflation rates that prevailed in Argentina as from 2002, which reduced power companies profits as revenues were fixed in Argentine pesos while costs increased due to inflation (81.3% accumulated inflation between 2002 and 2006) [24].

As a result of the institutional barrier presented by the regulatory changes in the sector and its consequent reduction in profitability previously explained (electricity prices were frozen, expressed in a devaluated Argentine peso and not paid in full even at those levels), many generators in Argentina stopped further investments in new generation capacity, as it can be demonstrated by the review of historical information about installed capacity in Argentina shown below.

Figures 3a and 3b show the evolution of the Argentine installed capacity and the electricity demand, respectively. Generation installed capacity only increased 3% between 2002 and 2007, growing from 23,609 MW in 2002[25] to 24,407 MW in 2007[26]. In contrast, electricity demand in

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[22]The country risk reached a maximum of 7,222 basis points in August 7, 2002 and had a medium value of 5,504 basis points between the beginning of 2002 and middle 2005: http://www.ambito.com/economia/mercados/riesgo-historico.asp?idpais=2.

[23] Resolution SE 240/2003 (http://www.infoleg.gov.ar/infolegInternet/anexos/85000-89999/87732/norma.htm), Resolution SE 406/2003 (http://www.infoleg.gov.ar/infolegInternet/anexos/85000-89999/88315/norma.htm), Resolution SE 943/2003 (http://www.infoleg.gov.ar/infolegInternet/anexos/90000-94999/90932/norma.htm).

[24] Consumer's Price Index, National Statistics and Census of Argentina (INDEC). Available at http://www.indec.gob.ar/.

[25] Argentina Wholesale Electricity Market Annual Report, CAMMESA, 2002.

[26] Argentina Wholesale Electricity Market Annual Report, CAMMESA, 2007.

Argentina increased in the same period by 33%, growing from 81,348 GWh in 2002 to 108,482 MWh in 2007[27].

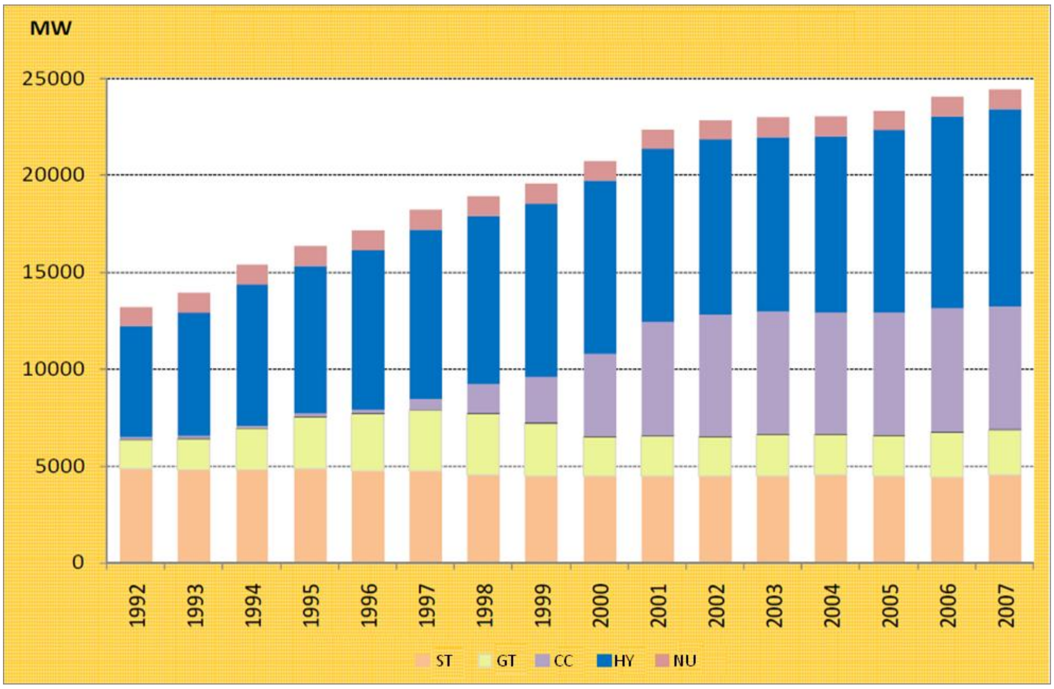

Figure 3a: Evolution of the installed capacity

Legends: ST=Steam Turbine, GT=Gas Turbine, CC=Combined Cycle, HY=Hydro, NU=Nuclear

[27] Argentina Wholesale Electricity Market Annual Report, CAMMESA, 2007.

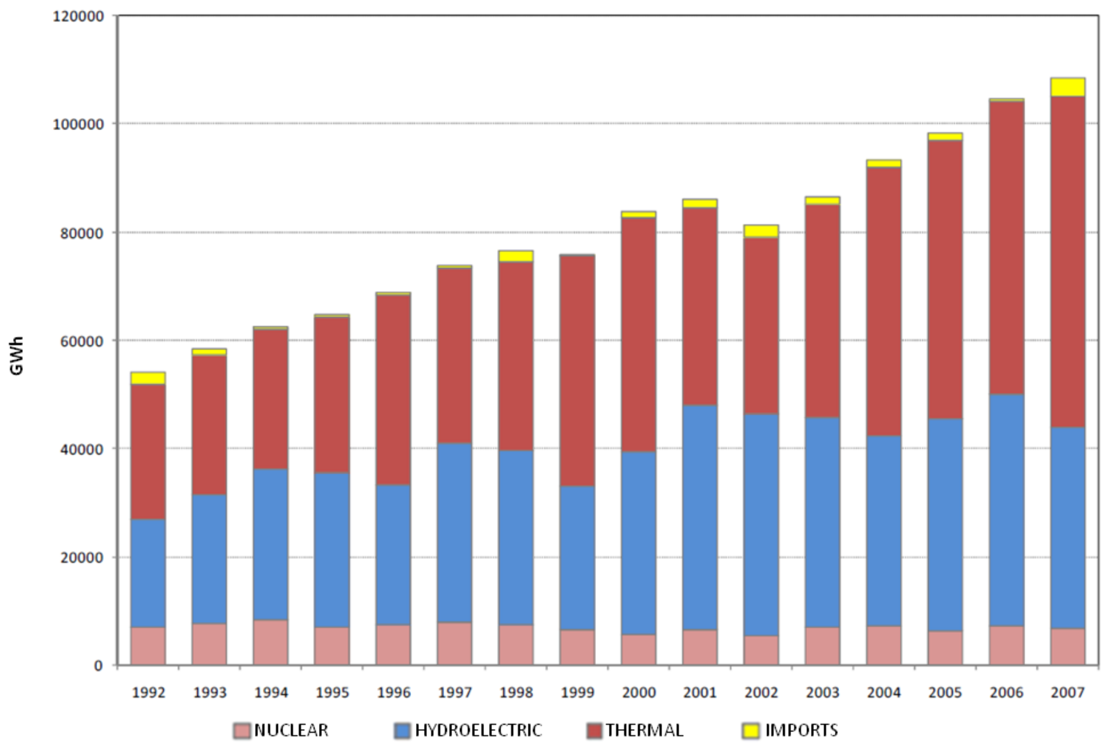

Figure 3b: Evolution of the electricity demand (GWh)

As a result of the lack of investments by existing and potential new investors in the sector, prior to the start date of the Project activity, electricity generators in Argentina were operating near its full capacity, which could lead to insufficient supply to meet the growing electricity demand[28].

The Argentine government implemented mitigating measures that were not sufficient to reverse this situation. One of these measures was aimed at increasing electricity generation installed capacity to meet a rising demand. In that sense, the National Secretariat of Energy launched, in September 2006, the "Energía Plus (Energy Plus)" Program[29], by which large consumers of electricity (power demand above 300 kW) were to contract the difference between their actual demand and their demand in the year 2005 with generation coming from new power plants built from September 2006 onwards, at prices expected to be higher than the spot price (which as mentioned earlier was capped at 120 AR$/MWh). Nevertheless, in June 2007 the government capped the price paid by consumers not entering into "Energía Plus" contracts at 185 AR$/MWh (Note 567/07 of June 2007[30]) effectively putting a cap reference on the prices that new generators could negotiate with large consumers (previously, large consumers not entering into "Energía Plus" contracts would have had to pay the marginal cost of the system) and reduced the

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[28] Electricity Sector Statistical Reports, http://energia3.mecon.gov.ar/contenidos/verpagina.php?idpagina=2599.

[29] Resolution SE 1,281/2006: http://www.edelap.com.ar/pdf/Res.%20SE%201281.pdf; http://www.energiaplus.com.ar/.

[30] http://www.energiasanjuan.com.ar/index.php?ver=resoluciones_consultas.

size of the potential demand of Energía Plus by limiting the need for large consumers to contract 100% of the difference between their actual demand and their demand in the year 2005, to 75% of it (Note 567/07 of June 2007[31]) and latter to 50% of it (Note 938/07 of August 2007[32] and 501/08 of May 2008[33]).

Despite the measures taken by the national government with the creation of the "Energía Plus" program, no generation projects were implemented under such program in the 12 months from the announcement of the plan up to the starting date of the Project activity. This new market represented a risk for the Project activity since it was uncertain how the "Energía Plus" market would evolve going forward, as (a) it had a limited demand given only by the extra demand of large users above their 2005 consumption (which was later limited to 50% of the extra demand, as explained above), and (b) the contracted "Energía Plus" price would be agreed between the involved parties but also needed to be reviewed and approved by the Secretariat of Energy, and was therefore also regulated[34]. The investment analysis presented in Annex 3 complements and reinforces this analysis, showing that the Project´s IRR is below the benchmark even under the context of the "Energía Plus" program.

In conclusion, Alternative 1 faces significant institutional barriers that prevent its implementation.

2. *Continuation of the current practice*:

   The continuation of single cycle plant operation does not present any institutional barrier, given that it does not require additional actions or investments.

5. *Renewable energy generation plant of equivalent capacity to the proposed Project*:

   The same institutional barriers than the ones applied to Alternative 1 are faced by Alternative 5.

- ***Investment Barriers***

1. *Project activity implemented as a non-CDM Project*:

   At the time of the start date of the Project activity, any new investment project by the electricity sector in Argentina faced a significant lack of private capital availability from domestic and international capital markets due to real and perceived risks associated with any new infra-structure investments in the country.

   The poor attractiveness of Argentina to drive private investment into infrastructure was demonstrated by the paper published in 2006 by the World Economic Forum within the

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[31] http://www.energiasanjuan.com.ar/ver.resoluciones_consultas_descargar.php?id=12

[32] http://www.epec.com.ar/docs/cooperativas/notas/Nota0938.pdf.

[33] http://www.energiasanjuan.com.ar/ver.resoluciones_consultas_descargar.php?id=27.

[34] Resolution SE 1,784/2006: http://www.infoleg.gov.ar/infolegInternet/anexos/120000-124999/122002/norma.htm.

framework of the Global Competitiveness Network, which qualified Argentina as a poor country to attract investments into infrastructure[35].

Brief Summary of the World Economic Forum Study
Chile, Brazil, Colombia and Peru lead the region with respect to the attractiveness of their private investment climate for infrastructure. Covering 12 economies in Latin America and the Caribbean, the study, 'Benchmarking National Attractiveness for Private Investment in Latin American Infrastructure', assesses the main drivers of private investment in infrastructure projects for ports, airports, roads and electricity. This is the first time that the World Economic Forum has developed an index specifically analysing the investment environment for infrastructure.

The study features the Infrastructure Private Investment Attractiveness Index (IPIAI), a customized, methodological tool gauging the institutions, factors and policies making it attractive for private investors to invest in infrastructure projects. An assessment of infrastructure investment opportunities is also performed for each of the countries covered.

Infrastructure Private Investment Attractiveness Index

Rank	Country	Score
1	Chile	5.43
2	Brazil	4.40
3	Colombia	4.33
4	Peru	4.23
5	Mexico	4.04
6	Uruguay	4.02
7	El Salvador	3.97
8	Guatemala	3.64
9	Argentina	3.41
10	Venezuela	3.37
11	Bolivia	3.34
12	Dominican Republic	3.33

The eight pillars measured by the IPIAI are:

- Macroeconomic environment: economic stability, market size and growth prospects
- Legal framework (rule of law), including regulatory efficiency, public ethics and the effectiveness of dispute settlement procedures
- Political risk
- Ease of access to information

[35] http://www3.weforum.org/docs/WEF_GCR_BenchmarkingNationalAttractiveness_PrivateInvestmentLA_2007.pdf.

- Sophistication and development of the financial markets that enable infrastructure financing
- The country track record on private investment in infrastructure over the past 15 years
- Relations between government and society, including society's willingness to pay for the services related to infrastructure
- Government readiness to deal with and ability to facilitate private investment in infrastructure

The twelve countries included in the study were grouped into four different clusters, each showing a specific attractiveness profile. The classification under a particular cluster has specific policy implications for a given country in that it indicates the reforms and policies to prioritize to catalyse high volumes of private investment in infrastructure, which differ from those for countries in other clusters.

With an environment extremely conducive to private investment in infrastructure, Chile is in a class of its own in the region. It is therefore no surprise that Chile has been one of the most salient countries worldwide in terms of the amount of private investment in infrastructure made in the past two decades.

In cluster 4, which includes Argentina, Bolivia and Venezuela, general investment conditions are poor. Most private infrastructure investment in these countries is related to industry-specific initiatives in areas where benefits are directly captured by investors (mining, oil and gas). The use of private investment to provide public goods is almost non-existent. The challenge for these countries is the adoption of an extensive agenda of reforms targeted at improving the general investment climate.

Following the guidance of the combined tool, investment barriers, other than insufficient financial returns, can be assessed by means of identifying the results presented by investment reports of reputed origin. The results of the study abovementioned presents that the poor attractiveness of Argentina to drive private investment to infra-structure reflected the lack of private capital availability from domestic and international capital markets due to real and perceived risks associated with any new investments in the country, including to the electricity sector.

Additionally, as described in the institutional barrier presented above, the existence of regulations that determined low electricity prices and limited profits have discouraged generation companies to invest in the expansion of the sector's installed capacity. It must be emphasized that the structural difficulties faced by the electricity sector have discouraged investments in either conversions or construction of combined cycle plants, as this will be further explained in the common practice analysis. These barriers to new investment had remained in place in the years following the start date of the Project activity, as reflected in the document presented by eight former Argentine Energy Secretaries in March, 2011, which concludes that Argentina had not expanded its energy supply (including electricity) in a magnitude enough to supply its

growing demand[36]. This leads to the fact that this alternative faces major investment barrier, other than insufficient financial returns.

In conclusion, the Alternative 1 faces investment barriers that prevent its implementation.

2. *Continuation of the current practice:*

The continuation of single cycle plant operation does not present any investment barrier, given that it does not require additional investments.

5. *Renewable energy generation plant of equivalent capacity to the proposed Project*:

The construction of a new hydropower plant of similar output than the proposed Project activity faces the same investments barriers as those described for Alternative 1 above. These barriers are further enhanced by the considerable total amount of the investment required to construct this scenario, and also due to the additional risk of changes in the regulatory environment that could affect its viability during its longer construction period before the start of commercial operations of the plant. The necessity of the Project participant to identify a site with sufficient hydraulic potential to develop a hydropower plant with annual output equivalent to the proposed Project activity and the need to obtain the required concession by the Government for its use, as described in Sub-step 1b.5, adds an additional uncertainty to the expected commencement of operations.

According to a study of the Argentine electricity sector, the construction of a hydropower plant would require significantly higher investment costs than a thermal power plant (more than 1,000 USD/kW versus 450 USD/kW, respectively)[37]. Under this perspective, the low electricity prices and the adoption of a threshold for marginal profits, as explained in the institutional barrier, naturally inhibit the implementation of energy Projects with higher investments requirements. This situation can be evidenced through the analysis of new hydro plants added to the national system from 2001 to 2006 (the last 5-year available data prior to the start of the project activity). According to the National Secretariat of Energy no important hydro capacity addition has been made in Argentina from 2001 to 2006[28]. Therefore, this alternative scenario faces significant investments barriers.

Table 4 summarizes the barriers analysis.

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[36] http://iae.org.ar/DECLARACION_DE_LOS_EX_SECRETARIOS_DE_ENERGIA_16_DE_MARZO_DE_2011.pdf , p.7.

[37] E. Fracchia; "Energy 2007". IAE, Austral University, July 2007; p. 15. Available at: http://www.edutecne.utn.edu.ar/debates/energia-07.pdf

Table 4: Barrier analysis

Scenario	Institutional barrier	Investment barriers	Final Result of the Barriers Analysis
Alternative 1	- Negative impact of new regulatory environment and economic context. - Low tariff values, frozen in Argentine pesos (previously US dollar denominated) and capped. - High inflation rate. - High devaluation after the 2002 crisis.	- Difficulties in attracting investments and raising capital. - Low electricity prices and limited profits. - Bad overall investment climate in Argentina.	- This scenario is prevented by major institutional and investment barriers and therefore could not be implemented without the CDM incentives.
Alternative 2	- This scenario faces no institutional barrier.	- This scenario faces no investment barrier.	- This scenario is not prevented by any relevant barriers. Hence this is considered as **baseline scenario.**
Alternative 5	- Negative impact of new regulatory environment and economic context. - Low tariff values, frozen in Argentine pesos (previously US dollar denominated) and capped. - High inflation rate. - High devaluation after the 2002 crisis.	- Difficulties in attracting investments and raising capital. - Low electricity prices and limited profits. - Bad overall investment climate in Argentina. - Higher investment requirements. - Longer construction period. -Availability of sites. - Government concession required.	- This scenario is prevented by major institutional and investment barriers.

Therefore, the alternative scenario to the Project activity that is not prevented by any barrier is Alternative 2: Continuation of the current practice.

Therefore, the baseline scenario is the continuation of the current practice. In the absence of the proposed Project activity the electricity to meet the demand in the grid system will be generated by:

(1) the operation of the Project power units in single cycle mode;
(2) the operation of existing grid-connected power plants; and
(3) the addition of new generation sources to the grid.

As per the combined tool the CDM incentives shall alleviates the identified barriers that prevent the proposed project activity from occurring.

The expected CDM registration of the project activity alleviates the major barriers faced by the project proponent besides enhancing shareholder confidence in domestic investment, especially in light of the historically supply-constrained Argentine energy market. In addition, the nature of the “carbon credits” and their qualitative impact in the project finance structure has also been an equally relevant issue.

As important as the marginal source of revenue provided by the CDM and its impact on the project finance is the effect of CDM eligibility in helping the project entity to further obtain additional sources of strong currency based revenues. It has significantly reduced the Loma de la Lata risk at the domestic level as well, by providing confidence to lenders\ shareholders to implement the project activity investment decision.

As per the combined tool if there is only one alternative scenario that is not prevented by any barrier, and if this alternative scenario is not the proposed project activity undertaken without being registered as a CDM project activity, then this alternative scenario is identified as the baseline scenario.

Step 3: Investment analysis

In order to reinforce the fact that the proposed project activity without being implemented as a CDM project is not the most attractive alternative to investors due to the barriers faced, even with the inclusion of the “Energía Plus” Program since this tariff scheme is not enough to overcome financial hurdles, an investment analysis under a benchmark approach is conducted in Annex 3.

Step 4: Common practice analysis

Common practice is analysed following the “Combined tool to identify the baseline scenario and demonstrate additionality”, ver. 04.0.0.

Step 4a: The proposed CDM project activity(s) applies measure(s) that are listed in the definitions section above

The definitions are met as shown in table 5.

Table 5: Common practice analysis

Condition	Fulfilment
Applicable geographical area	The relevant geographical area covers the entire host country, Argentina. This geographical area is compatible with the kind of interconnected system existing in Argentina, which covers the entire country. On the other hand, according to the extended definition of technology in the context of common practice, the investment climate prevailing at the date of investment decisions is only applicable to Argentina.
Measure	It corresponds to option (b) of the guidelines: Switch of technology with or without change of energy source (including energy efficiency improvement).
Output	The goods with comparable quality are the installed capacities of power plants connected to the grid (SADI) and delivering its electricity generation to the wholesale electricity market (MEM).
Different technologies	Option (d) Technologies implemented by private investors before the new sectoral framework (Resolutions 240/2003[38] and 406/2003[39] of the Secretariat of Energy) as a consequence of the Argentine crisis.

[38] http://www.infoleg.gov.ar/infolegInternet/anexos/85000-89999/87732/norma.htm.

Stepwise approach for common practice

Sub-step 4a(1): Calculate applicable output range as +/-50% of the design output or capacity of the proposed project activity.

The installed capacity of the combined cycle of the proposed Project activity is 545.66 MW, thus the range goes from 272.83 MW to 818.49 MW.

Sub-step 4a(2): In the applicable geographical area, identify all plants that deliver the same output or capacity, within the applicable output range calculated in Step 1, as the proposed project activity and have started commercial operation before the start date of the project. Note their number N_{all}. Registered CDM project activities shall not be included in this step.

The power plants that started operations before the start date of the Project activity in Argentina delivering the capacity established in Step 1 are listed below[40]:

Table 6: Power plants of Step 1

Power plant	Capacity (MW)	Date of commissioning[41]	Type
Luján de Cuyo	374	1998[42]	Comb. cycle
CTLLL (Neuquén)	375	Prior to 1997	Single cycle
Agua del Cajón	358	Prior to 1997	Single cycle
Agua del Cajón	304	2000	CC conversion
P. Banderita	450	Prior to 1997	Hydro
S. M. de Tucumán	382	2002	Comb. cycle
Tucumán	447	1999[43]	Comb. cycle
Buenos Aires	322	Prior to 1997	Comb. cycle
Genelba	674	1999[44]	Comb. cycle
Puerto	589	Prior to 1997	Single cycle
Puerto	789	2000	Comb. cycle
Nuevo Puerto	390	Prior to 1997	Single cycle
Dock Sud	773	2001	Comb. cycle
Piedrabuena	620	Prior to 1997	Single cycle
San Nicolás	650	Prior to 1997	Single cycle
Atucha	357	Prior to 1997	Nuclear
Futaleufú	472	Prior to 1997	Hydro

[39] http://www.infoleg.gov.ar/infolegInternet/anexos/85000-89999/88315/norma.htm.

[40] See file 'POTENCIA INSTALADA.xls'.

[41] http://energia3.mecon.gov.ar/contenidos/verpagina.php?idpagina=259.

[42] http://energia3.mecon.gov.ar/contenidos/archivos/publicaciones/INFO98.pdf.

[43] http://energia3.mecon.gov.ar/contenidos/archivos/publicaciones/INFO99.pdf.

[44] http://www.oceba.gba.gov.ar/prensa/modules.php?name=News&file=article&sid=20047.

C.N. Embalse	648	Prior to 1997	Nuclear
R. Grande	750	Prior to 1997	Hydro

CC stands for combined cycle

Therefore, N_{all} = 19.

Sub-step 4a(3): Within plants identified in Step 2, identify those that apply technologies different that the technology applied in the proposed project activity. Note their number N_{diff}.

Actually, all power plants are applying a different technology as defined in table 6, due to the reasons explained below. Thus N_{diff} = 19.

All power plants were commissioned before December 2001, when the Argentine crisis was triggered, except the combined cycle conversion of San Miguel de Tucumán thermal plant. This power plant started operations in February 2002, just two months after the crisis started since works were initiated before the crisis and were almost concluded when the crisis began. This represented a completely different regulatory and investment environment as the one faced by the Project activity. The crisis undergone by Argentina in 2001 had slowed investment in the sector. As outlined in the barrier analysis above, the new regulatory framework introduced extremely low electricity tariffs and created barriers to the implementation of the most efficient fossil fuel-based technology. Therefore, these 16 plants cannot be considered to be technologically similar to the proposed Project activity as they were designed and constructed in an era when those restrictions were absent. Even the 3 plants that are CC Conversion in table 6, in accordance with the guidelines on common practice (Definitions, Different Technologies, (d) Investment climate in the date of the investment decision), are different technologies.

On the other hand, between the end of 2001 and the start date of the Project activity no comparable power plants were commissioned.

Sub-step 4a(4): Calculate factor $F = 1 – N_{diff}/N_{all}$ representing the share of plants using technology similar to the technology used in the proposed project activity in all plants that deliver the same output or capacity as the proposed project activity.

Taking into account that N_{all} = 19 and N_{diff} = 19, F = 0.

After this stepwise approach it is concluded that F = 0 which is smaller than 0.2. Also $N_{all} – N_{diff} = 0$, which is lower than 3. Therefore, the proposed Project activity is not a common practice in Argentina.

B.5. Description of how the anthropogenic emissions of GHG by sources are reduced below those that would have occurred in the absence of the registered CDM Project activity (assessment and demonstration of additionality):

Assessment and demonstration of additionality:

Following the provisions of the methodology ACM007, this project activity applies the latest version of the “Combined tool to identify the baseline scenario and demonstrate additionality”.

Therefore, based on the described detailed assessment of baseline and the demonstrated results identified in Section B.4 above, this proposed project activity is additional. The additional revenues and benefits

promised by the CDM and the Project's contribution to the sustainable development of Argentina encouraged the Project Developer to conduct the Project activity.

CDM Consideration

The Project activity started on September 6, 2007, date when the contract between the Project developer and the engineering firm that would provide the equipments, installation and civil work was signed. The Project developer was aware of the CDM prior to this date since the very beginning of the Project activity idea. The timeline presented below demonstrates that the benefits of the CDM were a decisive factor in the decision to proceed with the Project and continuing and real actions were taken to secure CDM status for the Project in parallel with its implementation.

- *Between January and April 2006*: Pampa Energía S.A. acquired 8.66% of the capital stock of Central Puerto S.A. ("Central Puerto"), an important electricity generation company in Buenos Aires and the then owner of the assets composing Loma de la Lata. At the same time, Pampa Energía S.A. began its analysis regarding the closing of the cycle at Loma de la Lata.
- *May 2006:* Pampa Energía S.A. started conversations with Econergy Argentina to evaluate the CDM potential of the Project activity;
- *September 13, 2006*: Econergy presented a commercial proposal to be in charge of the validation process of the Project and purchase its CERs and an initial estimation of the amount of CERs to be generated by the Project.
- *December 4 2006:* Central Puerto S.A. agreed to sell the assets comprising Central Térmica Loma de la Lata to Pampa Energía S.A.;
- *March 12, 2007:* EcoSecurities presented a proposal to manage the Project´s validation process and to purchase its CERs. (EcoSecurities started conversations with Pampa Energía S.A. before that date, however there are no formal evidences to sustain that until March)
- *May 17, 2007:* Closing of the acquisition of the Central Térmica Loma de la Lata by Project Developer.
- *July 6, 2007:* A Pampa Energía S.A. Board Meeting took place in which it was stated that its subsidiary, the Project developer was in advanced negotiations with carbon consulting companies (MGM and EcoEnergy) to develop the CDM component, essential source of revenue that would turn the Project economically viable.
- *July 11, 2007:* EcoSecurities continued negotiating a proposal until November 2007, when the Project developer informed that the proposal had been accepted.
- *September 6, 2007:* starting date of the Project activity. Date when the contract between the Project developer and the engineering firm that provides the equipments, installation and civil work was signed.
- *September 8, 2007:* local newspaper published an article about the Project activity and its implementation as CDM Project[45].
- *November 29, 2007:* EcoSecurities Project Implementation Team performed a site visit to Pampa Energía S.A. to achieve information and documentation required to start the implementation of the CDM Project.

[45] Rio Negro Online: http://www1.rionegro.com.ar/diario/2007/09/08/20079r08s06.php.

- *December 10, 2007*: the Project Developer signed the CDM Emission Reduction Purchase Agreement with EcoSecurities relating to the Combined Cycle at Loma de la Lata Thermo Unit Project.
- *January until October 2008:* EcoSecurities and the Project Developer worked in the elaboration of a CDM Project Design Document.
- *September 2008:* start of civil works at Project site.
- *November 6, 2008:* First PDD version was published for global stakeholder consultation (start of validation).
- *January 28, 2010:* Project submitted for registration.
- *March 17, 2011:* Project rejected by the CDM-EB.
- *January 2012:* Project resubmitted to the UNFCCC for global stakeholder process.

Therefore, the CDM was seriously considered in the decision to implement the Project activity.

Thus, the proposed Project activity is additional.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

Emission Reductions

The Project activity mainly reduces GHG emissions through substitution of power generation supplied by the existing generation sources connected to the grid and likely future additions to the grid. According to the methodology the greenhouse gas emission reductions achieved by the project activity during a given year y (*ERy*) shall be estimated as follows:

$$ER_y = BE_y - PE_y - L_y \quad (1)$$

where:

ERy	are the emissions reductions during the year y in tonnes of CO_2,
BEy	are the baseline emissions during the year y in tonnes of CO_2,
PEy	are the project emissions during the year y in tonnes of CO_2,
Ly	are the leakage emissions during the year y in tonnes of CO_2.

Project Emissions

Project emissions (PE_y) are determined using the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion", ver. 02.

$$PE_y = PE_{FC,j,y} = \sum_i FC_{i,j,y} \times COEF_{i,y}$$

where:

$PE_{FC,j,y}$	are the CO_2 emissions from fossil fuel combustion in process *j* during the year *y* (tCO_2/yr),

$FC_{i,j,y}$ is the quantity of fuel type *i* combusted in process *j* during the year *y* (mass or volume unit/yr),
$COEF_{i,y}$ is the CO_2 emission coefficient of fuel type *i* in year *y* (tCO_2/mass or volume unit)
i are the fuel types combusted in process *j* during the year *y*.

Process j stands for natural gas consumption by the gas turbines and diesel consumption in Emergency equipment of the steam turbine during the year y.

$COEF_{i,y}$ is calculated according to option B of the Tool as:

$$COEF_{i,y} = NCV_{i,y} \times EF_{CO_2,i,y}$$

where
$NCV_{i,y}$ Weighted average net calorific value of the fuel type *i* used in year *y* (GJ/mass or volume unit),
$EF_{CO2,i,y}$ Weighted average CO_2 emission factor of fuel type *i* used in year *y* (tCO_2/GJ).

Baseline emissions

The baseline scenario is the generation of electricity by the operation of the Project power unit(s) in single cycle mode as well as by grid-connected power plants. The Project will partially displace electricity generated by the Project power unit(s) in the baseline scenario. In addition, it will also displace electricity in the grid, since the quantity of electricity generation by the plant increases as a result of the Project activity. The calculation of baseline emissions is therefore based on the three cases shown in figure 4.

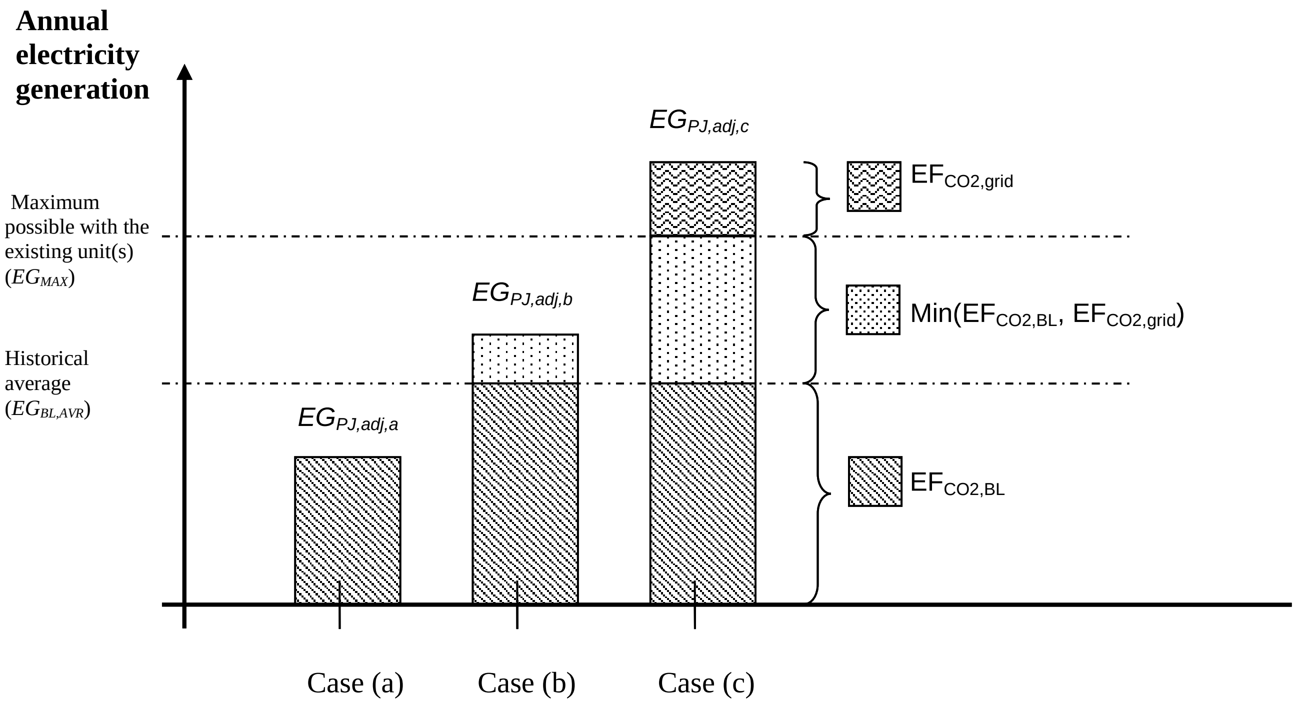

Figure 4: Baseline emissions calculation for three cases of different quantities of electricity generated

The baseline emissions for year *y* (BE_y) are calculated as follows:

Step 1: Determination of the baseline emissions for different scenarios of project electricity generation

Case (a) The quantity of electricity generated in the project power unit(s), adjusted for changes to efficiency, ($EG_{PJ,adj,y}$) is lower than or equal to the historic average annual generation level ($EG_{BL,AVR}$). Baseline emissions are calculated as:

$$BE_y = EG_{PJ,adj,y} \cdot EF_{CO2,BL} \quad (2)$$

Case (b) The quantity of electricity generated in the project power unit(s), adjusted for changes to efficiency, ($EG_{PJ,adj,y}$) exceeds the historic average annual generation level ($EG_{BL,AVR}$) but is lower than or equal to the maximum annual quantity of electricity that the project power unit(s) could have produced prior to the implementation of the project activity (EG_{MAX}). Baseline emissions are calculated as:

$$BE_y = EG_{BL,AVR} \cdot EF_{CO2,BL,y} + \left(EG_{PJ,adj,y} - EG_{BL,AVR}\right) \cdot \min\left(EF_{CO2,BL}; EF_{grid,y}\right) \quad (3)$$

Case (c) The quantity of electricity generated in the project power unit(s), adjusted for changes to efficiency, ($EG_{PJ,adj,y}$) exceeds the maximum annual quantity of electricity that the project power unit(s) could have produced prior to the implementation of the project activity (EG_{MAX}). Baseline emissions are calculated as:

$$BE_y = EG_{BL,AVR} \cdot EF_{CO2,BL,y} + \left(EG_{MAX} - EG_{BL,AVR}\right) \cdot \min\left(EF_{CO2,BL,}; EF_{grid,y}\right) + \left(EG_{PJ,adj,y} - EG_{MAX}\right) \cdot EF_{grid,y} \quad (4)$$

Where:

BE_y	=	Baseline emissions in year *y* (tCO_2/yr),
$EG_{PJ,adj,y}$	=	Quantity of electricity supplied by all project power units to the electricity grid in year *y*, adjusted for changes to efficiency (MWh/yr),
$EG_{BL,AVR}$	=	Average annual quantity of electricity supplied by all project power units to the electricity grid during the defined operational history (MWh/yr),
EG_{MAX}	=	Maximum annual quantity of electricity that could be generated by all project power units in the baseline scenario (MWh/yr),
$EF_{CO2,BL}$	=	Baseline emission factor of all project power units operated in single cycle mode (tCO_2/MWh),
$EF_{grid,y}$	=	Emission factor of the electricity grid to which the project power unit is connected (tCO_2/MWh).

Taking into account the values used in calculations case (c) is the one applicable to this Project.

The maximum annual quantity of electricity that could be generated by the Project power unit(s) in the baseline scenario (EG_{MAX}) is calculated as:

$$EG_{MAX} = CAP_{max} \cdot T_{max} \quad (5)$$

Where:

EG_{MAX}	=	Maximum annual quantity of electricity that could be generated by all project power units in the baseline scenario (MWh/yr),

CAP_{max}	=	Maximum gross power generation capacity of the project power unit(s) prior to the implementation of the project activity (MW),
T_{MAX}	=	Maximum amount of time during a year in which the project power unit(s) could have operated at full power generation capacity prior to the implementation of the project activity (hours/yr).

All Project power units have three years operational history and there was no major retrofit during this period in any of the units, so that the maximum annual amount of time that the Project power unit(s) could have operated at full load prior to the validation of the Project activity is calculated according to equation (6). Otherwise as a simplification, T_{MAX} equals 8,760 hours/yr.

$$T_{MAX} = 8,760 - \frac{\sum_{x=1}^{3} HMR_x}{3} \qquad (6)$$

Where:

T_{MAX}	=	Maximum amount of time during a year in which the project power unit(s) could have operated at full power generation capacity prior to the implementation of the project activity (hours/yr),
HMR_x	=	Average number of hours during which the plant did not operate due to maintenance or repair in year x (hours/yr),
x	=	Each year during the three years operational history.

HMR_{2008} = 342 hours
HMR_{2009} = 1,573 hours
HMR_{2010} = 1,098 hours

$$T_{MAX} = 8,760 - \frac{(342+1,573+1,098)}{3} = 8,760 - 1,004 = 7,756 \text{ hours}$$

The average annual amount of electricity supplied to the electricity grid by the project power unit(s) in the three years historical period is calculated according to equation (7). This calculation is based on data from only those units that have at least a three years operational history and no major retrofit during this period (i.e. all the project units).

$$EG_{BL,AVR} = \frac{\sum_{x=1}^{3} EG_x}{3} \qquad (7)$$

Where:

$EG_{BL,AVR}$	=	Average annual quantity of electricity supplied by all project power units to the electricity grid during the three year operational history (MWh/yr),
EG_x	=	Quantity of electricity supplied by the project power unit(s) with three years operational history and no retrofit in this period, to the electricity grid in year x (MWh/yr),
x	=	Each year of the three years operational history.

The total amount of electricity supplied to the grid ($EG_{PJ,y}$) is conservatively adjusted by applying a discount factor based on the minimum of the monitored efficiencies after the implementation of the project activity, as described in the equations below:

$$EG_{PJ,adj,y} = EG_{PJ,y} \cdot \frac{\eta_{PJ,\min,y}}{\eta_{PJ,y}} \qquad (8)$$

with

$$\eta_{PJ,\min,y} = \min(\eta_{PJ,1},...,\eta_{PJ,y}) \qquad (9)$$

Where:

$EG_{PJ,adj,y}$	=	Quantity of electricity supplied by all project power units to the electricity grid in year *y*, adjusted for changes to project power plant efficiency (MWh/yr),
$EG_{PJ,y}$	=	Total amount of electricity supplied to the electricity grid by the project power units in year *y* (MWh/yr),
$\eta_{PJ,min,y}$	=	Minimum of the yearly average energy efficiency of the project power unit(s) monitored during the previous years (1 to y) after the implementation of the project activity for year *y*,
$\eta_{PJ,i} \cdots \eta_{PJ,y}$	=	Average energy efficiency of the project power unit(s) in years 1 to y of the crediting period (refer to $\eta_{PJ,y}$ in the monitoring tables).

Step 2: Estimating the emissions factor for electricity generated in single cycle mode in the baseline ($EF_{CO2,BL}$)

Since all Project power units have a three years operational history and there was no major retrofit in these unit during this period, then the baseline CO_2 emissions factor for the Project power unit(s) operated in single cycle mode ($EF_{CO2,BL}$) is determined based on the historical performance of the units and calculated according to equation (10). Otherwise, $EF_{CO2,BL}$ is calculated according to equation (11).

$$EF_{CO2,BL} = \frac{\sum_{x=1}^{3}\sum_{i} FC_{i,x} \times NCV_{i,x}}{\sum_{x=1}^{3} EG_{x}} \times EF_{CO2,min}$$

Where:

$EF_{CO2,BL}$	=	CO_2 emission factor for electricity generated in single cycle mode in the baseline (tCO_2/MWh),
$FC_{i,x}$	=	Quantity of fuel type *i* used by the project power unit(s) in year *x* (mass or volume unit/yr),
$NCV_{i,x}$	=	Net calorific value of the fuel type *i* used by the project power unit(s) in year *x* (GJ/mass or volume unit),
$EF_{CO2,min}$	=	CO_2 emission factor of the least carbon intensive fuel type used by the project power unit(s) during the three years operational history (tCO_2/GJ),
EG_x	=	Quantity of electricity supplied by the project power unit(s) with three years operational history and no retrofit in this period, to the electricity grid in year x (MWh/yr),

x = Each year of the three years operational history.

If three years operational history is not available for all the units or if there was a major retrofit during this period in any of the units, then the CO_2 emission factor for electricity generated in single cycle mode in the baseline ($EF_{CO2,BL}$) is determined using the default values for the efficiency of the power units from Annex 1 of the "Tool to calculate the emission factor for an electricity system", according to the following equation:

$$\mathrm{EF}_{\mathrm{CO2,BL}} = \frac{3.6}{\eta} \times \mathrm{EF}_{CO2,\min} \qquad (11)$$

Where:

$EF_{CO2,BL}$ = CO_2 emission factor for electricity generated in single cycle mode in the baseline (tCO_2/MWh),

$EF_{CO2,min}$ = CO_2 emission factor of the least carbon intensive fuel type used by the project power unit(s) during the three years operational history (tCO_2/GJ),

η = Default efficiency of the project power unit(s) operated in single cycle mode.

Equation (10) is the one used in the proposed project activity since there are three years of operational history where no retrofits were made over the units. Equation (11) is not considered in this PDD.

Step 3: Determine the emissions factor for the grid electricity system ($EF_{grid,y}$)

The baseline emission factor for the grid ($EF_{grid,y}$) is calculated as a combined margin emission factor, using the "Tool to calculate the emission factor for an electricity system", ver. 02.2.1.

Step 3.1: Identify the relevant electricity systems

Argentina has a National interconnected electricity system, the SADI. It is a grid with around 370,000 km of low, medium and high voltage lines. Every power plant dispatching electricity to the grid will be using the SADI. The commercial transactions are controlled by the Wholesale Electricity Market Administrator, CAMMESA, under a competitive market system (the SADI is a system with spot market for electricity under the MEM).

The Argentina DNA through the Secretariat of Energy (a member of the Executive Committee) publishes a delineation of the Project electricity system, the above mentioned SADI grid.

Moreover, during 2010 electricity imports contributed with only 2% of the total electricity delivered to the SADI. Considering that there is only one interconnected electricity system in Argentina, there are no existing electricity imports from other grids inside Argentina. The only imported electricity distributed by the SADI is electricity coming from power generation in other countries. Thus, according to the *Tool to calculate the emission factor for an electricity system* (ver. 02.2.1): For imports from connected electricity systems located in another host country(ies), the emission factor is 0 tons CO_2 per MWh.
Following the tool guidelines, electricity exports are not subtracted from electricity generation data used to calculate the baseline emission factor. On the other hand, no significant constraints occur so that the whole national interconnected grid is considered and defined by the spatial extent of the power plants that are physically connected through transmission and distribution lines to the combined cycle power plant locations where electricity is being saved. This electricity system is the only to be used for the calculation of the operating margin emission factor and for the calculation of the build margin emission factor, since

there are no recent or likely future additions to transmission capacity to enable significant increases in imported electricity.

All the information regarding the Argentine power sector SADI is publicly available at:

- CAMMESA webpage[46]
- Secretariat of Energy webpage[47]

Step 3.2: Choose whether to include off-grid power plants in the project electricity system (optional)

Given that Argentina is fully interconnected by the SADI and that off-grid power generation represents a small portion of the electricity consumed in the country (0.87% during 2009[48]), Step 3.2 is excluded from the baseline methodology procedure since the proposed Project activity would only displace electricity dispatched to the SADI.

Step 3.3: Select a method to determine the operating margin (OM)

Based on the baseline determination and description provided in previous sections of this PDD, and considering that:

- The proposed Project activity will displace electricity from the SADI
- Off-grid producers are not to be considered by the baseline methodology procedure (excluded from the spatial extent)
- All the information pertaining to the SADI is accessible (Secretariat of Energy and CAMMESA), including robust and reliable dispatch data

Option (c) from the *Tool to calculate the emission factor for an electricity system*, ver. 02.2.1, the Dispatch Data Analysis method, has been chosen as the most representative method to determine the OM. The dispatch data analysis is going to be applied in an ex-post basis.

Step 3.4: Calculate the operating margin emission factor according to the selected method

OM calculation according to the following selected option:

<u>(c) Dispatch data analysis OM</u>

Following the guidelines from the *Tool to calculate the emission factor for an electricity system*, ver.02.2.1, the dispatch data analysis OM emission factor is determined based on the grid power units that are actually dispatched at the margin during each hour when the Project is displacing electricity from the SADI. Given that this approach is not applicable to historical data, annual monitoring and update of the

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[46] http://portalweb.cammesa.com/default.aspx

[47] http://energia3.mecon.gov.ar/home/.

[48] Informe Estadístico del Sector Eléctrico 2009 (Statistical Report of the Electric Sector 2009), Secretariat of Energy: http://www.energia.gov.ar/contenidos/verpagina.php?idpagina=3368.

emission factor is required and will be implemented by the Project proponent in order to comply with the dispatch data analysis OM requirements. Thus, the ex post option is considered.

The following set of equations describes the OM calculation approach.

$$EF_{Grid,OM-DD,y} = \frac{\sum_h EG_{PJ,h} \cdot EF_{EL,DD,h}}{EG_{PJ,y}}$$

Where:

$EF_{Grid,\ OM-DD\ ,\ y}$	Dispatch data analysis operating margin CO_2 emission factor in year *y* (tCO_2e/yr),
$EG_{PJ,\ h}$	Electricity displaced by the project activity in hour *h* of year *y* (MWh),
$EF_{EL,\ DD,\ h}$	CO_2 emission factor for grid power units in the top of the dispatch order in hour *h* in year *y* (tCO_2/MWh),
h	Hours in year *y* in which the project activity is displacing grid electricity,
y	Year in which the project activity is displacing grid electricity.

The following data is calculated by Project Participant:[49]

- Hourly emission factors of the 10% marginal set of power plants serving the system for calculating the dispatch data analysis OM
- Build margin data

The Argentine Secretariat of Energy makes publicly available the following data:

- National fuel emission factors[50]

These are based on information provided by CAMMESA, which is available to participants of the wholesale electricity market,[51] i.e.

- Hourly fuel consumption by fuel type burned by power units of the SADI
- Hourly generation of those power units
- Marginal generation costs and merit order of power units

Thus, the following approach is applied in order to obtain the hourly grid emission factor:

[49] Data calculated by Project Participant using CAMMESA's Argentine power system (SADI) information and guidelines from the "Tool to calculate the emission factor for an electricity system", ver. 02.2.1. The back-up calculation files (summary of OM 2011 "PP's Calculation of OM 2011.xlsb", each month's hourly OM 2011 calculation, from January to December each file generically identified as "OM 2011 day by day mmyyyy.xlsb" and "2011 Argentine grid building margin.xlsx") are handed in for detailed information.

[50] Source: Second National Communication to UNFCCC, page 179.

[51] In case of delay of the publication of annual data the standard procedure of going to year y – 1 will be followed.

$$EF_{EL,DD,h} = \frac{\sum_{i,n} FC_{i,n,h} \times NCV_{i,y} \times EF_{CO2,i,y}}{\sum_{n} EG_{n,h}}$$

Where:

$EF_{EL,\ DD\ ,\ h}$	CO_2 emission factor for grid power units in the top of the dispatch order in hour *h* in year *y* (tCO_2/MWh),
$FC_{i,\ n,\ h}$	Amount of fossil fuel type *i* consumed by grid power unit *n* in hour *h* (mass or volume unit),
$NCV_{i,y}$	Net calorific value (energy content) of fossil fuel type *i* in year *y* (GJ/mass or volume unit as published by the 2nd National Communication of Argentina to the UNFCCC)
$EF_{CO2,\ i,\ y}$	CO_2 emission factor of fossil fuel type *i* in year *y* (tCO_2/GJ as provided by the 2nd National Communication of Argentina to the UNFCCC),
$EG_{n,\ h}$	Net electricity generated and delivered to the grid by grid power unit *n* in hour *h* (MWh),
n	Grid power units in the top of the dispatch,
i	Fossil fuel types combusted in grid power unit *n* in year *y*,
h	Hours in year *y* in which the project activity is displacing grid electricity,
y	Year in which the project activity is displacing grid electricity.

NOTE: If during the crediting period there is any need to apply other emission factors than the ones provided by the Secretariat of Energy, for example IPCC, and they are expressed in tCO_2/TJ or any other energy unit, then the following equation should be applied.

$$EF_{EL,DD,h} = \frac{\sum_{i,n} FC_{i,n,h} \cdot NCV_{i,y} \cdot EF_{CO2,i,y}}{\sum_{n} EG_{n,h}}$$

Where:

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

The grid power units in the top of the dispatch will be determined according to the information provided by CAMESSA and based in the following guidelines.

The group *n* of power plants in the dispatch margin is the set of power plants in the top x% of total electricity dispatched by the grid system during hour *h*, where x% is equal to the greater of either:

- 10%; or
- The project generation during hour *h* expressed as a percentage of the total grid generation for that hour.

Step 3.5: Calculate the build margin (BM) emission factor

According to the “Tool to calculate the emission factor for an electricity system” (version 02.2.1), Option 1 is selected: For the first crediting period, the build margin emission factor shall be fixed ex ante. For the second crediting period the ex ante option is used, i.e. updated based on the most recent information available on units already built at the time of submission of the request for renewal of the crediting period

to the DOE. For the third crediting period, the build margin emission factor calculated for the second crediting period shall be used.

The sample group of power units *m* used to calculate the build margin is determined as per the following procedure:

(a) Identify the set of five power units, excluding power units registered as CDM project activities, that started to supply electricity to the grid most recently ($SET_{5\text{-units}}$) and determine their annual electricity generation ($AEG_{SET\text{-}5\text{-units}}$, in MWh);

(b) Determine the annual electricity generation of the project electricity system, excluding power units registered as CDM project activities (AEG_{total}, in MWh). Identify the set of power units, excluding power units registered as CDM project activities, that started to supply electricity to the grid most recently and that comprise 20% of AEG_{total} (if 20% falls on part of the generation of a unit, the generation of that unit is fully included in the calculation) ($SET_{\geq 20\%}$) and determine their annual electricity generation ($AEG_{SET\text{-}\geq 20\%}$, in MWh);

(c) From $SET_{5\text{-units}}$ and $SET_{\geq 20\%}$ select the set of power units that comprises the larger annual electricity generation (SET_{sample});

Identify the date when the power units in SET_{sample} started to supply electricity to the grid. If none of the power units in SET_{sample} started to supply electricity to the grid more than 10 years ago, then use SET_{sample} to calculate the build margin. Ignore steps (d), (e) and (f).

Otherwise:

(d) Exclude from SET_{sample} the power units which started to supply electricity to the grid more than 10 years ago. Include in that set the power units registered as CDM project activity, starting with power units that started to supply electricity to the grid most recently, until the electricity generation of the new set comprises 20% of the annual electricity generation of the project electricity system (if 20% falls on part of the generation of a unit, the generation of that unit is fully included in the calculation) to the extent is possible. Determine for the resulting set ($SET_{sample\text{-}CDM}$) the annual electricity generation ($AEG_{SET\text{-}sample\text{-}CDM}$, in MWh);

If the annual electricity generation of that set comprises at least 20% of the annual electricity generation of the project electricity system (i.e. $AEG_{SET\text{-}sample\text{-}CDM} \geq 0.2 \times AEG_{total}$), then use the sample group $SET_{sample\text{-}CDM}$ to calculate the build margin. Ignore steps (e) and (f).

Otherwise:

(e) Include in the sample group $SET_{sample\text{-}CDM}$ the power units that started to supply electricity to the grid more than 10 years ago until the electricity generation of the new set comprises 20% of the annual electricity generation of the project electricity system (if 20% falls on part of the generation of a unit, the generation of that unit is fully included in the calculation);

(f) The sample group of power unit m used to calculate the build margin is the resulting set ($SET_{sample\text{-}CDM\text{-}>10yrs}$).

The BM emission factor is calculated according to the following equation:

$$EF_{Grid,BM,y} = \frac{\sum_m EG_{m,y} \cdot EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

Where:

$EF_{Grid,BM,y}$	Build margin CO_2 emission factor in year *y* (tCO_2e/yr),
$EG_{m,y}$	Net quantity of electricity generated and delivered to the grid by power unit *m* in year *y* (MWh),
$EF_{EL,m,y}$	CO_2 emission factor of power unit *m* in year *y* (tCO_2/MWh),
m	Power units included in the build margin,
y	Most recent historical year for which power generation data is available.

$EF_{EL,m,y}$ is determined according to the following equation:

$$EF_{EL,m,y} = \frac{\sum_i FC_{i,m,y} \cdot NCV_{i,y} \cdot EF_{CO_2,i,y}}{EG_{m,y}}$$

Where

$EF_{EL,m,y}$	CO_2 emission factor of power unit *m* in year *y* (tCO_2/MWh)
$FC_{i,m,y}$	Amount of fossil fuel type *i* consumed by power unit *m* in year *y* (Mass or volume unit)
$NCV_{i,y}$	Net calorific value (energy content) of fossil fuel type *i* in year *y* (GJ/mass or volume unit)
$EF_{CO2,i,y}$	CO_2 emission factor of fossil fuel type *i* in year *y* (tCO_2/GJ)
$EG_{m,y}$	Net quantity of electricity generated and delivered to the grid by power unit *m* in year *y* (MWh)
m	All power units serving the grid in year *y* except low-cost/must-run power units
i	All fossil fuel types combusted in power unit *m* in year *y*
y	The relevant year as per the data vintage chosen

Step 3.6: Calculate the combined margin emission factor

Once the OM and BM are calculated, the combined margin emission factor is calculated using method (a) of the Tool, the weighted average CM, as follows:

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

Where:

$EF_{grid,BM,y}$	Build margin CO_2 emission factor in year *y* (tCO_2e/MWh),
$EF_{grid,OM,y}$	Operating margin CO_2 emission factor in year *y* (tCO_2e/MWh),
W_{BM}	Weighting of build margin emission factor (%),
W_{OM}	Weighting of operating margin emission factor (%).

Following the *Tool to calculate the emission factor for an electricity system* (ver. 02.2.1) and since the proposed project activities consist of thermal power generation, the weighting of the operating and build margin for the first and subsequent crediting periods will be:

W_{BM} = 0.5
W_{OM} = 0.5

Leakage

The main emissions potentially giving rise to leakage in the context of the proposed projects are:

(i) Emissions associated with the situation that exhaust heat was already recovered prior to the implementation of the project activity, in which case the diversion of this heat to the project power unit(s) may increase emissions elsewhere; and

(ii) Emissions associated with extraction, production, transportation, distribution and processing of an increased quantity of fossil fuels consumed by the project activity ($LE_{upstream,y}$).

Leakage emissions are calculated as follows:

$$LE_{y} = LE_{upstream,y} + LE_{HR,y} \qquad (12)$$

Where:

LE_y = Leakage emissions in year *y* (tCO_2e/yr),

$LE_{upstream,y}$ = Leakage emissions associated with the upstream emissions of an increase in fossil fuel use in the project activity in year *y* (tCO_2e/yr),

$LE_{HR,y}$ = Leakage emissions due to a decrease in the amount of heat recovered from exhaust heat for purposes other than power generation in the project, compared to the most recent year prior to the implementation of the project activity, in year *y* (tCO_2e/yr).

Determination of $LE_{HR,y}$

If the quantity of heat recovered from the exhaust heat during the most recent year prior to the implementation of the project activity ($Q_{HR,x}$) is either less than 3% of the fossil fuels consumed by the project power units in an energy basis or is smaller or equal to the amount of heat recovered from exhaust heat in year *y* for purposes other than power generation ($Q_{HR,y}$), then emissions from this leakage source are equal to zero.

Otherwise, $LE_{HR,y}$ is calculated as the amount of reduction in heat recovery multiplied by the emission factor for the most carbon intensive fuel used during the operational history of the project power unit(s) according to equation 14. If a fuel blended with biofuels was used in the operational history, then the emission factor for this fuel should be considered to be the emission factor for the fossil fuel used in the blend.

$$LE_{HR,y} = \left(Q_{HR,x} - Q_{HR,y}\right) \cdot EF_{CO2,max} \qquad (13)$$

Where:

$LE_{HR,y}$ = Leakage emissions due to a decrease in the amount of heat recovered from exhaust heat for purposes other than power generation in the project, compared to the most recent year prior to the implementation of the project activity, in year y (tCO_2e/yr),
$Q_{HR,x}$ = Quantity of heat recovered from the exhaust heat of the project power unit(s) during the most recent year prior to the implementation of the project activity (GJ/yr),
$Q_{HR,y}$ = Quantity of heat recovered from the exhaust heat of the project power unit(s) for purposes other than power generation in year *y* (GJ/yr),
$EF_{CO2,max}$ = CO_2 emission factor of the of the most carbon intensive fuel type used by the project power unit(s) in the operational history (tCO_2/GJ).

Equation (13) is not applicable since prior to project implementation there was not any recovery of exhaust gases.

Determination of $LE_{upstream,y}$

In cases where the fuel consumption in the project activity is lower than the historical fuel consumption in the three historical years *x*, leakage emissions from this source are equal to zero. Otherwise, leakage emissions associated with the upstream emissions from an increase in fossil fuel use in the project activity shall be considered. The leakage emissions are calculated as follows:

$$LE_{upstream,y} = \max\left[0, \left(\sum_i \left(FC_{i,y} \cdot NCV_{i,y} \cdot EF_{i,upstream,CH4}\right) \cdot GWP_{CH4} + LE_{LNG,CO2,y}\right) \cdot \left(1 - \frac{\frac{1}{3} \cdot \sum_{x=1}^{3} \sum_i FC_{i,x} \cdot NCV_{i,x}}{\sum_i FC_{i,y} \cdot NCV_{i,y}}\right)\right]$$

(14)
Where:
$LE_{upstream,y}$ = Leakage emissions associated with the upstream emissions from an increase in fossil fuel use in the project activity in the year *y* (tCO_2e/yr)
$FC_{i,y}$ = Quantity of fuel type *i* used by the project power unit(s) in year *y* (mass or volume unit/yr)
$NCV_{i,y}$ = Average net calorific value of the fuel type *i* used by the project power unit(s) in year *y* (GJ/mass or volume unit)
$EF_{i,upstream,CH4}$ = Emission factor for upstream fugitive methane emissions from production, transportation, distribution of fossil fuel i used by the project power unit(s) in year *y* (tCH_4/GJ)
GWP_{CH4} = Global warming potential of methane valid for the relevant commitment period (tCO_2e/tCH_4)
$LE_{LNG,CO2,y}$ = Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system in year *y* (tCO_2e/yr)
$FC_{i,x}$ = Quantity of fuel type *i* used by the project power unit(s) in year *x* (mass or volume unit/yr)
$NCV_{i,x}$ = Net calorific value of fuel type i used by the project power unit(s) in year *x* (GJ/mass or volume unit)
x = Each year of the three years operational history

Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($LE_{LNG,CO2,y}$) are calculated, where applicable, as follows:

$$LE_{LNG,CO2,y} = FC_{LNG,y} \times NCV_{LNG,y} \times EF_{CO2,upstream,LNG} \quad (15)$$

Where:

$LE_{LNG,CO2,y}$	=	Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system in year *y* (tCO_2e/yr)
$FC_{LNG,y}$	=	Quantity of natural gas produced from LNG used by the project power unit(s) in year *y* (mass or volume unit/yr)
$NCV_{LNG,y}$	=	Net calorific value of natural gas produced from LNG used by the project power unit(s) in year *y* (GJ/mass or volume unit)
$EF_{CO2,upstream,LNG}$	=	Emission factor for upstream CO_2 emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system (t CO_2e/GJ)

Equation (15) is not applicable to the proposed Project activity since there is neither fossil nor electricity consumptions associated with any other process.

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

Data / Parameter:	EG_x
Data unit:	MWh/yr
Description:	Quantity of electricity supplied by the Project power unit(s) with three years operational history and no retrofit in this period, to the electricity grid in year *x*
Source of data used:	CAMMESA. PP generation records with historical data of electricity supplied by the Project to the grid in the defined operational history
Value applied:	**2008**: 1,744,469; **2009**: 925,817; **2010**: 447,738
Justification of the choice of data or description of measurement methods and procedures actually applied:	Values were measured using electricity meters by CAMMESA as those described in the monitoring plan
Any comment:	The consistency of metered net electricity generation is cross-checked with receipts from sales (if available). Meters are subject to regular maintenance and calibration. Year *x* refers to each year of the unit’s three years operational history (2008, 2009, and 2010)

Data / Parameter:	$FC_{i,x}$
Data unit:	m^3/yr
Description:	Quantity of natural gas used by the Project power unit(s) in year *x*
Source of data used:	Fuel supplier. PP historical records of annual fuel consumption by the Project operating in single cycle mode
Value applied:	<table><tr><th>2008</th><th>2009</th><th>2010</th></tr><tr><td>585,005,098</td><td>312,905,078</td><td>154,490,255</td></tr></table>
Justification of the choice of data or description of measurement methods and procedures actually applied:	Values measured using flow meters by the fuel supplier as those described in the monitoring plan
Any comment:	The data for any direct measurements with volume meters at the plant site is cross-checked with an annual energy balance that is based on purchased quantities. Meters are subject to regular maintenance and calibration. Year *x* refers to each year of the unit's operational history (2008, 2009, and 2010)

Data / Parameter:	$NCV_{NG,x}$
Data unit:	GJ/tonne
Description:	Net calorific value of natural gas used by the Project power unit(s) in year *x*
Source of data used:	According to option (a) for net calorific value of natural gas of the Methodology ACM0007, ver. 06.1.0, values would be provided by the fuel supplier in invoices. If option (a) is not available, according to said Methodology, values would be provided from: - Option (b): measurements by Project Participant - Option (c): regional or national default values based on well-documented, reliable sources - Option (d): IPCC default values at the upper limit of the uncertainty at a 95% confidence interval as provided in table 1.2 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories At the current moment, the Project Participant expects that the data source available would be provided from fuel supplier
Value applied:	<table><tr><th>2008</th><th>2009</th><th>2010</th></tr><tr><td>47.798</td><td>48.049</td><td>47.944</td></tr></table>Values provided by fuel supplier

Justification of the choice of data or description of measurement methods and procedures actually applied:	Calculated from data provided by the fuel supplier. Measurements were undertaken in line with national and international fuel standards. Chromatography samples are taken by the fuel provider
Any comment:	The values are within the uncertainty range of the IPCC default values as provided in Table 1.2, Vol. 2 of the 2006 IPCC Guidelines. The laboratory follows international standards. Year *x* refers to each year of the unit's operational history

Data / Parameter:	$EF_{CO2,min}$
Data unit:	tCO_2/GJ
Description:	CO_2 emission factor of the least carbon intensive fuel type (natural gas) used by the Project power unit(s) during the three years operational history
Source of data used:	According to option (a) for CO_2 emission factor of the Methodology ACM0007, ver. 06.1.0, values would be provided by the fuel supplier in invoices. If option (a) is not available, according to said Methodology, values would be provided from: - Option (b): measurements by Project Participant - Option (c): regional or national default values based on well-documented, reliable sources - Option (d): IPCC default values at the upper limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories Data source required by said Methodology is compatible with the required by the 'Tool to calculate the emission factor for an electricity system', ver. 02.2.1. At the current moment, the Project Participant expects that the data source available would be provided from fuel supplier
Value applied:	**2008**: 0.05555; **2009**: 0.05540; **2010**: 0.05546 Values provided from fuel supplier
Justification of the choice of data or description of measurement methods and procedures actually applied:	Calculated from data provided by the fuel supplier. Measurements were undertaken in line with national and international fuel standards. Chromatography samples are taken by the fuel provider
Any comment:	The values are within the uncertainty range of the IPCC default values as provided in Table 1.4, Vol. 2 of the 2006 IPCC Guidelines. The laboratory follows international standards

Data / Parameter:	$EF_{CO2,max}$
Data unit:	tCO_2/GJ
Description:	CO_2 emission factor of the most carbon intensive fuel type (natural gas) used by the Project power unit(s) during three years operational history
Source of data used:	According to option (a) for CO_2 emission factor of the Methodology ACM0007, ver. 06.1.0, values would be provided by the fuel supplier in invoices. If option (a) is not available, according to said Methodology, values would be provided from: - Option (b): measurements by Project Participant - Option (c): regional or national default values based on well-documented, reliable sources - Option (d): IPCC default values at the upper limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories Data source required by said Methodology is compatible with the required by the 'Tool to calculate the emission factor for an electricity system', ver. 02.2.1. At the current moment, the Project Participant expects that the data source available would be provided from fuel supplier
Value applied:	**2008**: 0.05555; **2009**: 0.05540; **2010**: 0.05546 Values provided from fuel supplier
Justification of the choice of data or description of measurement methods and procedures actually applied:	Calculated from data provided by the fuel supplier. Measurements were undertaken in line with national and international fuel standards. Chromatography samples are taken by the fuel provider
Any comment:	The values are within the uncertainty range of the IPCC default values as provided in Table 1.4, Vol. 2 of the 2006 IPCC Guidelines. The laboratory follows international standards

Data / Parameter:	CAP_{max}
Data unit:	MW
Description:	Maximum gross power generation capacity of the Project power unit(s) prior to the implementation of the Project activity
Source of data used:	Maximum generation capacity determined by performance tests under optimal operation conditions (optimal load, after maintenance, etc.)
Value applied:	369.93
Justification of the choice of data or description of measurement methods and procedures actually applied:	Values taken from manufacturer's specifications

Any comment:	Test performed on gas turbines for determining the maximum power capacity: **4.1 *OBJECTIVE*** The primary objective of this test was to measure the electrical output, heat rate, and auxiliary power consumption of the units and compare to rated values. Additional parameters were measured to support correction from the actual test conditions to the rated conditions. The performance will be considered compliant when the test results are better than the rated values, allowing for measurement uncertainty. Rated Performance Total Plant Net Generator Output @ Generator Terminals: 369,930 kW Net Heat Rate (LHV): 2,550 kcal / kW hr Auxiliary Power Consumption: 439 kW (per unit) Rated Conditions Ambient Pressure: 1.0135 bar Compressor Inlet Air Temperature: 15° C Compressor Inlet Air Humidity: 60 % Generator Power Factor: 0.85 Natural Gas Fuel: Per Specification Gas Turbine Speed: 3000 rpm Gas Turbine & Auxiliary Equipment: New and Clean Test Tolerances Generator Output: 1.0 % Heat Rate: 1.5 %

Data / Parameter:	T_{max}
Data unit:	hours/yr
Description	Maximum amount of time during a year in which the Project power unit(s) could have operated at full power generation capacity prior to the implementation of the Project activity
Source of data used:	Data registered by the PP
Value applied:	7,756 (calculated as per equation 6)
Justification of the choice of data or description of measurement methods and procedures actually applied:	Unavailability of units due to maintenance or repairs was taken into account (it is not considering the load factor according to dispatch of the units)
Any comment:	Unavailability of units due to the works related to the conversion from the single cycle to the combined cycle power plant is not taken into account in this factor

Data / Parameter:	HMR_x
Data unit:	hours/yr
Description:	Average number of hours during which the plant did not operate due to maintenance or repair in year *x* (hours)

Source of data used:	Project activity site
Value applied:	<table><tr><th>2008</th><th>2009</th><th>2010</th></tr><tr><td>342</td><td>1,573</td><td>1,098</td></tr></table>
Justification of the choice of data or description of measurement methods and procedures actually applied:	Historical records of the unavailability of units due to maintenance or repairs by PP
Any comment:	Year *x* refers to each year of the unit's three years operational history (2008, 2009, and 2010)

Data / Parameter:	GWP_{CH4}
Data unit:	tCO_2e/tCH_4
Description:	Global warming potential of methane valid for the relevant commitment period
Source of data used:	IPCC
Value applied:	For the first commitment period: 21
Justification of the choice of data or description of measurement methods and procedures actually applied:	It is the value adopted for CDM projects
Any comment:	It will be updated according to CDM EB guidelines

Data / Parameter:	$EF_{grid,BM,y}$
Data unit:	tCO_2/MWh
Description:	Build margin CO_2 emission factor for grid connected power generation
Source of data used:	Project Participant using SADI's information provided by CAMMESA for the year 2011
Value applied:	0.466
Justification of the choice of data or description of measurement methods and procedures actually applied :	Ex ante calculation of the BM for 2011 based on the Tool to calculate the emission factor for an electricity system, ver. 02.2.1. For further information please refer to Annex 3 and spreadsheet "2011 Argentine grid building margin.xlsx"
Any comment:	This value will be updated for the renewal of the crediting period

Data / Parameter:	w_{OM}
Data unit:	Fraction
Description:	Weighting
Source of data used:	Tool to calculate the emission factor for an electricity system, ver. 02.2.1
Value applied:	0.5
Justification of the choice of data or description of measurement methods and procedures actually applied :	Default weighting value for Operating Margin according with the tool
Any comment:	This value will be updated for the renewal of the crediting period

Data / Parameter:	w_{BM}
Data unit:	Fraction
Description:	Weighting
Source of data used:	Tool to calculate the emission factor for an electricity system, ver.02.2.1
Value applied:	0.5
Justification of the choice of data or description of measurement methods and procedures actually applied :	Default weighting value for Operating Margin according with the tool
Any comment:	This value will be updated for the renewal of the crediting period

B.6.3. Ex-ante calculation of emission reductions:

The required steps to conduct ex-ante estimations are presented in the table 7 below.

Table 7: Technical data used in emission calculations

Baseline	**Symbol**	**Unit**	**Source**	**Value**	**Reference**
Grid Emission Factor	$EF_{grid,y}$	tCO_2/MWh	Calculated with CAMMESA information	0.616	Combined margin grid emission factor 2011
CO_2 emission factor of natural gas used by the project power unit(s) during the 2008 operational history (2008)	$EF_{CO2,min}$	$tonCO_2/GJ$	Project developer	0.0556	Calculated from natural gas supplier chromatographies
CO_2 emission factor of natural gas used by the project power unit(s) during the 2009 operational history (2009)	$EF_{CO2,min}$	$tonCO_2/GJ$	Project developer	0.0554	Calculated from natural gas supplier chromatographies

CO_2 emission factor of natural gas used by the project power unit(s) during the 2010 operational history (2010)	$EF_{CO2,min}$	$tonCO_2/GJ$	Project developer	0.0555	Calculated from natural gas supplier chromatographies
Max CO_2 emission factor of natural gas used by the project power unit(s) during the three years operational history (2008-2010)	$EF_{CO2,NG,max}$	$tonCO_2/GJ$	Project developer	0.0556	Calculated from natural gas supplier chromatographies
Min CO_2 emission factor of natural gas used by the project power unit(s) during the three years operational history (2008-2010)	$EF_{CO2,NG,min}$	$tonCO_2/GJ$	Project developer	0.0554	Calculated from natural gas supplier chromatographies
Net calorific value of Natural Gas used by the project power unit(s) in year 2008	$NCV_{NG,x}$	TJ/Gg	Project developer	47.80	Calculated from natural gas supplier chromatographies
Weighted average density of natural gas 2008	$\rho_{NG,y}$	Gg/m^3	Natural gas supplier	7.04E-07	Calculated from natural gas supplier chromatographies
Net Calorific Value Natural Gas 2008	$NCV_{i,x}$	GJ/m^3	Calculated	3.37E-02	Calculated from natural gas supplier chromatographies
Net calorific value of Natural Gas used by the project power unit(s) in year 2009	$NCV_{NG,x}$	TJ/Gg	Project developer	48.05	Calculated from natural gas supplier chromatographies
Weighted average density of natural gas 2009	$\rho_{NG,y}$	Gg/m^3	Natural gas supplier	7.00E-07	Calculated from natural gas supplier chromatographies
Net Calorific Value Natural Gas 2009	$NCV_{i,x}$	GJ/m^3	Calculated	3.36E-02	Calculated from natural gas supplier chromatographies
Net calorific value of Natural Gas used by the project power unit(s) in year 2010	$NCV_{NG,x}$	TJ/Gg	Project developer	47.94	Calculated from natural gas supplier chromatographies
Weighted average density of natural gas 2010	$\rho_{NG,y}$	Gg/m^3	Natural gas supplier	7.01E-07	Calculated from natural gas supplier chromatographies
Net Calorific Value Natural Gas 2010	$NCV_{i,x}$	GJ/m^3	Calculated	3.36E-02	Calculated from natural gas supplier chromatographies
Max. Net calorific value of Natural Gas used by the project power unit(s) between year 2008-2010	$NCV_{NG,max}$	TJ/Gg	Project developer	48.05	Calculated from natural gas supplier chromatographies
Min Net calorific value of Natural Gas used by the project power unit(s) between years 2008- 2010	$NCV_{NG,min}$	TJ/Gg	Project developer	47.80	Calculated from natural gas supplier chromatographies
Open Cycle Gross Installed Capacity	CAP_{max}	MW	Technology provider	369.93	Three (3) natural gas turbines General Electric PG 9171 E of 123.31 MW each one. GE Guarantee, July 29th 1994 and turbines photos.
Auxiliary consumption of the plant	-	MW	Technology provider	1.32	Three (3) natural gas turbines. Each one consumes 439 kW. GE Warranty, July 29th 1994.
Open Cycle Maximum Net Installed Capacity	OC	MW	Calculated	368.61	-
Operational hours/year	T_{MAX}	hrs/yr	Project developer	7,756	-
Load Factor	-	%	Project developer	89.9%	Study of projects at Thermal Power Plants Güemes and Loma La Lata and their operation in the Wholesale Electricity Market (MEM), "Mercados Energéticos Consultores", May 2007
Reserve for frequency regulation	-	%	Project developer / CAMMESA	3%	CAMMESA, Frequency reg. 2007
Effective load factor		%	Calculated	86.9%	-

Steam turbine gross installed capacity		MW	Project developer	175.73	Siemens Steam Turbine Operations' Conditions
Auxiliary consumption of the plant		MW	Project developer	7.65	Isolux Corsán proposal, Annex I Off-shore Electrical System 2007/5287-E-001 (4 Sept. 2007)
Steam turbine net capacity	-	MW	Calculated	168.08	-
Weighted average net calorific value of Natural Gas in year y	$NCV_{NG,y}$	TJ/Gg	Project developer	47.93	Calculated average 2008-2009-2010 from natural gas supplier chromatographies
Weighted average density of natural gas	$\rho_{NG,y}$	Gg/m^3	Natural gas supplier	7.02E-07	Calculated average 2008-2009-2010 from natural gas supplier chromatographies
Net Calorific Value Natural Gas	$NCV_{i,y}$	GJ/m^3	Calculated	3.36E-02	Calculated average 2008-2009-2010 from natural gas supplier chromatographies
Weighted average CO2 emission factor of natural gas in year y	$EF_{CO2,i,y}$	$tonCO_2/GJ$	Project developer	0.0555	Calculated average 2008-2009-2010 from natural gas supplier chromatographies
Quantity of diesel oil used by the Emergency Project power units (GE SSAA TV) in year *y*	$FC_{ST.DO,y}$	tonne/year	Project developer	1.5708	Calculated according to Technical specifications supplier of 360 kVA generation set, and 0.202 kg/kWh full consumption at 100 % load, normalised to 0.9 kW/kVA and with 24 hr/yr.
Average net calorific value of diesel oil used by the Emergency Project power units(GE SSAA TV) in year y	$NCV_{ST,DO,y}$	GJ/tonne	2nd National Communication of Argentina to UNFCCC	42.7100	Used data of Appendix 1 of the 2nd National Communication of Argentina to UNFCCC
Weighted average CO_2 emission factor of diesel oil in year y	$EF_{CO2,DO,y}$	tCO_2/GJ	2nd National Communication of Argentina to UNFCCC	0.0744	Used data of Appendix 1 of the 2nd National Communication of Argentina to UNFCCC
CO_2 emission coefficient of diesel oil in year y	$COEF_{ST,y}$	tCO_2/tonne	Calculated	4.9882	Calculated

Leakage					
Emission factor for upstream fugitive methane emissions from production, transportation, distribution of fossil fuel i used by the project power unit(s) in year y	EFi,upstream, CH4	tCH_4/GJ	ACM0007, v6.1.0	7.20E-05	Value corresponding to US production
Global warming potential of methane valid for the relevant commitment period (tCO_2e/tCH_4)	GWP_{CH4}	tCO_2e/tCH_4	IPCC	21	Adopted by the Kyoto Protocol

To calculate the Project emissions it is important to consider that the conversion of Loma de la Lata power plant from single to combined cycle represents an increase of its efficiency, thus a reduction of its marginal cost.

In Argentina CAMMESA (Wholesale Electric Market Administration Company) coordinates the power plants dispatch according with the marginal cost criteria (merit order dispatch). Therefore, the plants with the lowest price to supply power or higher efficiency for the same type of fuel are dispatched first.

In conclusion, according with the merit order criteria of CAMMESA, the Project activity will have a better ranked dispatch than the baseline (single cycle).

The average load factor of the single cycle considering the most recent six years prior to the start of operation of the Project was 38.2%.

Data	Symbol	Units	2005	2006	2007	2008	2009	2010	Average Baseline
Load Factor	LF	%	38.8	39.1	54.9	54.0	28.7	13.9	**38.2**

The load factor of the combined cycle was defined in the early stages of the Project according to a third party (external consultancy) contracted by the Project Developer to evaluate the future evolution of the Wholesale Electricity Market and determine the economic electricity generation of the Project activity. The study was based on the same Dispatch Models (OSCAR and MARGO) utilized by CAMMESA. The conclusion was that the Project activity will operate at full dispatch if there is natural gas available at competitive prices (as previously discussed in PDD sections B.4 and B.5). The estimated load factor was 89.9%.[52]

Based on this report, and applying a security margin established by CAMMESA for reserve for frequency regulation (3%), the Project developer considered reasonable and conservative to base its financial projections on a load factor of 86.9%.

As a result, the power plant load factor increases from 32.2% operating as single cycle (average of the three years prior to start of the Project) to 86.9% operating as combined cycle.

Therefore, due to the Project activity there is an increase of the natural gas consumed to operate the gas turbines.

No supplementary natural gas is consumed by the Heat Recovery Steam Generators.

Equations applied to the specific project case

Equation (5) is:

$$EG_{MAX} = CAP_{max} \cdot T_{max}$$

where T_{max}, according to equation (6) gives:

$$T_{MAX} = 8{,}760 - \frac{\sum_{x=1}^{3} HMR_x}{3}$$

[52] Mercados Energéticos Consultores (May 2007). Report available for the DOE at validation.

HMR_{2008}= 342 hours
HMR_{2009}= 1,573 hours
HMR_{2010}=1,098 hours

$$T_{max} = 8{,}760 - \frac{(342+1{,}573+1{,}098)}{3} = 8{,}760 - 1{,}004 = 7{,}756 \text{ hours}$$

Equation (5) gives:

$$\mathrm{EG}_{\mathrm{MAX}} = \mathrm{CAP}_{\max} \cdot \mathrm{T}_{\max} = 369.93\,MW \cdot 7{,}756\,hr = 2{,}869{,}101\,MWh/yr$$

Where CAP_{max} is taken from manufacturer's specifications and T_{max} is calculated discounting the average number of hours during which the plant did not operate due to maintenance and repair in the three years prior to Project implementation (equation 6).

The grid emission factor is calculated according to the combined margin approach, based on the calculations for the operating margin (OM) and building margin (BM) by the Project Participant using SADI's information, provided by CAMMESA for the year 2011 (please refer to the summary spreadsheet "PP's Calculation of OM 2011.xlsb" and "2011 Argentine grid building margin.xlsx" for the detailed calculation).

$$EF_{Grid,OM-DD,y} = 0.765\ tCO_2e/MWh$$

$$EF_{Grid,BM,y} = 0.466\ tCO_2e/MWh$$

$$EF_{grid,CM,y} = EF_{grid,OM-DD,y} \times 0.5 + EF_{grid,BM,y} \times 0.5$$

$$EF_{grid,y} = EF_{grid,CM,y} = 0.765\,tCO_2e/MWh \times 0.5 + 0.466\,tCO_2e/MWh \times 0.5 = 0.616\,tCO_2e/MWh$$

In the calculation of the BM emission factor a CDM project was included, Project 1482: *Conversion of existing open cycle gas turbine to combined cycle at the Central Térmica Patagonia power station, Comodoro Rivadavia, Argentina*, registered on 02/05/2008. See Annex 3 for details.

Based on historical consumptions:

Symbol	Units	2008	2009	2010	Average Baseline
EG_x	MWh/yr	1,744,469	925,817	447,738	1,039,341

Equation (7) results:

$$EG_{BL,AVR} = \frac{\sum_{x=1}^{3} EG_x}{3} = 1{,}039{,}341\ MWh/yr$$

Equation (8) proposes a discount in order to take into account that future energy efficiency improvement measures (e.g. measures that may be implemented after the project activity) do not result in emissions reductions. Up to present no improvements are forecasted so that the most plausible hypothesis is that $\eta_{PJ,min,y} = \eta_{PJ,y}$, so that $EG_{PJ,min,y} = EG_{PJ,y}$ (equations 8 and 9).

Based on historical fuel consumption:

Symbol	Units	2008	2009	2010	Average Baseline
$FC_{i,x}$	m^3	585,005,098	312,905,078	154,490,255	350,800,144

Baseline CO_2 emissions factor for the Project power units operated in single cycle mode ($EF_{CO2,BL}$) is determined according to equation (10):

$$EF_{CO2,BL} = \frac{\sum_{x=1}^{3}\sum_{i} FC_{i,x} \times NCV_{i,x}}{\sum_{x=1}^{3} EG_x} \times EF_{CO2,min} = (585{,}005{,}098\ m^3/yr \times 0.0337\ GJ/m^3 +$$

$$+312{,}905{,}078\ m^3/yr \times 0.0336\ GJ/m^3 + 154{,}490{,}255\ m^3/yr \times 0.0366\ GJ/m^3)/3{,}118{,}024\ MWh/yr$$

$$\times 0.0554\ tCO_2/GJ = 0.629\ tCO_2/MWh$$

Where $EF_{CO2,min}$ is calculated from chromatography samples taken and provided by the natural gas supplier.

Using the calculated values, equation (4) corresponding to case (c) becomes:

$$BE_y = EG_{BL,AVR} \cdot EF_{CO2,BL,y} + (EG_{MAX} - EG_{BL,AVR}) \cdot \min(EF_{CO2,BL,}; EF_{grid,y}) + (EG_{PJ,adj,y} - EG_{MAX}) \cdot EF_{grid,y}$$

$$= 1{,}039{,}341\ MWh/yr \cdot 0.629\ tCO_2/MWh + (2{,}869{,}101 - 1{,}039{,}341\ MWh/yr) \cdot 0.616\ tCO_2/MWh + (3{,}617{,}196\ MWh/yr - 2{,}869{,}101\ MWh/yr) \cdot 0.616\ tCO_2/MWh = 2{,}240{,}694\ tCO_2/yr$$

On the other hand, taking into account the increased natural gas consumption of the gas turbines due to the increase of the load factor and the eventual consumption of diesel oil in emergency Project power unit and that:

$$COEF_{NG,y} = NCV_{NG,y} \times EF_{CO_2,NG,y} = 0.0336\,GJ/m^3 \times 0.0555\,tCO_2/GJ = 0.00187\,tCO_2/m^3$$

$$COEF_{DO,y} = NCV_{DO,y} \times EF_{CO_2,DO,y} = 42.71\,GJ/tn \times 0.0744\,tCO_2/GJ = 3.1757\,tCO_2/tn$$

Project emissions are given by:

$$PE_y = \sum_i FC_{i,j,y} \times COEF_{i,y} = 838{,}529{,}451\,m^3/yr \times 0.00187\,tCO_2/m^3$$
$$+1.418\,tn/yr \times 3.1757\,tCO_2/tn = 1{,}564{,}290\,tCO_2/yr$$

The first term corresponds to gas consumption by the power plant and the second one Diesel consumption of emergency equipment.

Leakage is given by emissions associated with the upstream emissions of an increase in fossil fuel use in the Project activity. Considering that Central Térmica Loma de la Lata takes the natural gas of the adjacent field, processing, transportation and distribution is not involved. It is also reflected in the price paid by the natural gas which does not include transportation and distribution costs. Thus, the upstream emission factor does not take into account processing, transportation and distribution leaks. Moreover, considering that in the Second National Communication of Argentina to the UNFCCC[53] it is shown that the oil and gas is a mature industry, that the associated gas is preserved, the system is highly reliable, equipment is well maintained using high quality components, line breaks and well explosions are not frequent, the industry is strictly regulated where legislation is in force, it can be concluded that US/Canada natural gas emission factors can be used, i.e. 72 tCH_4/PJ for production. Equation (14) yields to:

$$LE_{upstream,y} = \max\left[0, \left(\sum_i \left(FC_{i,y} \cdot NCV_{i,y} \cdot EF_{i,upstream,CH4}\right) \cdot GWP_{CH4} + LE_{LNG,CO2,y}\right) \cdot \left(1 - \frac{\frac{1}{3} \cdot \sum_{x=1}^{3} \sum_i FC_{i,x} \cdot NCV_{i,x}}{\sum_i FC_{i,y} \cdot NCV_{i,y}}\right)\right]$$

= 24,794 tCO_2/yr

Introducing the values obtained in equation (1), expected annual emission reductions are:

$$ER_y = BE_y - PE_y - LE_y = 651{,}610\,tCO_2/yr$$

[53] Argentinean National Greenhouse Gases Inventory 2000, Volume II; Page 189. Available at: http://aplicaciones.medioambiente.gov.ar/archivos/web/UCC/File/comunicaciones_nacionales/parte2_inventario_gases.pdf.

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

Year	Estimation of project activity emissions (tonnes of CO_2e)	Estimation of baseline emissions (tonnes of CO_2e)	Estimation of leakage (tonnes of CO_2e)	Estimation of overall emission reductions (tonnes of CO_2e)
1 Sept. 2012 – 31 Dec. 2012	522,859	748,944	8,287	217,798
2013	1,564,290	2,240,694	24,794	651,610
2014	1,564,290	2,240,694	24,794	651,610
2015	1,564,290	2,240,694	24,794	651,610
2016	1,564,290	2,240,694	24,794	651,610
2017	1,564,290	2,240,694	24,794	651,610
2018	1,564,290	2,240,694	24,794	651,610
1 Jan. 2019 – 31 Aug. 2019	1,041,431	1,491,750	16,507	433,812
Total (tonnes of CO_2e)	**10,950,030**	**15,684,858**	**173,558**	**4,561,270**

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

B.7.1 Data and parameters monitored:

Data / Parameter:	$EG_{PJ,y}$
Data unit:	MWh/yr
Description:	Total amount of electricity supplied to the electricity grid by the Project power units in year *y*
Source of data to be used:	Generation records taken from CAMMESA and checked by Central Térmica Loma de la Lata
Value of data applied for the purpose of calculating expected emission reductions in section B.5:	3,617,196
Description of measurement methods and procedures to be applied:	Measured continuously (recorded every 15 minutes) with SMEC (Sistema de Medición Comercial, Commercial Measurement System), for the monitoring plan the CAMMESA monthly or daily post-operative report will be used

QA/QC procedures to be applied:	The consistency of metered net electricity generation will be cross-checked with receipts from sales. The accuracy of 8 equipments for SMEC systems are Class 0.2 s (one principal and one of back up for each TG and the TV). The contrast and calibration when is necessary frequency is annual for all of them. The accuracy of the equipment for MEGA[54] gas processing plant is Class 0.5. The contrast and calibration (when is necessary) frequency is annual.
Any comment:	

Data / parameter:	$FC_{i,y}$
Data unit:	m^3/yr
Description:	Quantity of natural gas used by the Project power units (gas turbines) in year *y*
Source of data to be used:	Onsite measurements by the fuel supplier
Value of data applied for the purpose of calculating expected emission reductions in section B.5:	838,529,450
Description of measurement methods and procedures to be applied:	Measured continuously with orifice plates (through differential pressure transmitters) at the entrance of the power plant by the fuel supplier The monitoring frequency of this parameter is continuous, being the data registered on a daily basis. The reporting of this parameter is carried out monthly, consisting in aggregating the daily data.
QA/QC procedures to be applied:	The consistency of metered fuel consumption quantities will be cross-checked by an annual energy balance that is based on purchased quantities and stock changes. It is a conservative value since it includes losses. The metered fuel consumption quantities will also be cross-checked, when possible, with available purchase invoices from financial records. Computer System and Chromatograph of PM N° 81 considered standard of the Protocol are AGA Report No. 3 for orifice plate and API system and "Flow Measurement using electronic metering systems" MPMS Chapter 21, Section 1, Electronic Gas Measurement. The admissible relative error of the gas flow measurement will be calculated according to the AGA Report No. 3, Part 1 “General Equations and Uncertainty Guidelines”. For both Orifice Plates, the calibration frequency is annual. For the Computer System, the calibration frequency is quarterly. For the Chromatograph, the calibration frequency is monthly. The described values for calibration frequency will depend on the revised version of said Protocol, which is pending of signature
Any comment:	

[54] See section B.7.2.

Data / Parameter:	$\eta_{PJ,y}$
Data unit:	-
Description:	Average energy efficiency of the Project power units in year *y* of the crediting period
Source of data to be used:	Project activity site by PP
Value of data applied for the purpose of calculating expected emission reductions in section B.5:	1
Description of measurement methods and procedures to be applied:	Once during each year y of the crediting period. The first calculation will be made during the first year after implementing the Project activity. It is calculated using a direct method (dividing the net electricity generation by the energy content of the fuels fired during a representative time period) and not the indirect method (determination of fuel supply or heat generation and estimation of the losses)
QA/QC procedures to be applied:	This efficiency will be cross-checked with annual energy balance of the plant
Any comment:	The efficiency is referred in terms of the net calorific values of the fuels used and the net electricity produced, i.e. total electricity produced minus internal consumption of electricity

Data / Parameter:	$NCV_{i,y}$
Data unit:	GJ/tonne
Description:	Average net calorific value of natural gas used by the Project power units in year *y*
Source of data to be used:	According to option (a) for net calorific value of the Methodology ACM0007, ver. 06.1.0, values would be provided by the fuel supplier in invoices. If option (a) is not available, according to said Methodology, values would be provided from: - Option (b): measurements by Project Participant - Option (c): regional or national default values based on well-documented, reliable sources - Option (d): IPCC default values at the lower limit of the uncertainty at a 95% confidence interval as provided in Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories At the current moment, the Project Participant expects that the data source available would be provided from chromatography data provided by the fuel supplier. These data is provided as a recording report monthly via delivery certificate
Value of data applied for the purpose of calculating expected emission reductions in section B.5:	47.93 (average of the period 2008-2010 from chromatography data provided by the fuel supplier)

Description of measurement methods and procedures to be applied:	Measurements are undertaken through chromatography analysis in line with international fuel standards by the fuel supplier and National Normative (ENARGAS) Values of this parameter are reported monthly and they are calculated with daily data report
QA/QC procedures to be applied:	It will be verified that the values are within the uncertainty range of the IPCC default values as provided in Table 1.2, Vol. 2 of the 2006 IPCC Guidelines. If the values fall below this range additional information from the testing laboratory will be collected to justify the outcome or conduct additional measurements
Any comment:	The laboratory complies with international quality standards

Data / Parameter:	$EF_{i,upstream,CH4}$
Data unit:	tCH_4/GJ
Description:	Emission factor for upstream fugitive methane emissions from production, transportation, distribution of natural gas used by the Project power units in year *y*
Source of data to be used:	Default emission factors corresponding to US production are used:

Activity	Unit	Default emission factor
Coal		
Underground mining	t CH4 / kt coal	13.4
Surface mining	t CH4 / kt coal	0.8
Oil		
Production	t CH4 / PJ	2.5
Transport, refining and storage	t CH4 / PJ	1.6
Total	t CH4 / PJ	4.1
Natural gas		
USA and Canada		
Production	t CH4 / PJ	72
Processing, transport and distribution	t CH4 / PJ	88
Total	t CH4 / PJ	160
Eastern Europe and former USSR		
Production	t CH4 / PJ	393
Processing, transport and distribution	t CH4 / PJ	528
Total	t CH4 / PJ	921
Western Europe		
Production	t CH4 / PJ	21
Processing, transport and distribution	t CH4 / PJ	85
Total	t CH4 / PJ	105
Other oil exporting countries / Rest of world		
Production	t CH4 / PJ	68
Processing, transport and distribution	t CH4 / PJ	228
Total	t CH4 / PJ	296

Value of data applied for the purpose of calculating expected emission reductions in section B.5:	72 tCH_4/PJ

Description of measurement methods and procedures to be applied:	Taken from ACM0007 (IPCC default values)
QA/QC procedures to be applied:	As defined per the methodology
Any comment:	This parameter is only required to calculate the upstream leakage emissions

Data to be monitored for the calculation of the grid emission factor according to the dispatch data analysis operating margin method:

Data / Parameter:	$EG_{n,h}$
Data unit:	MWh
Description:	Net electricity generated and delivered to the grid by power unit *n* in hour *h*
Source of data to be used:	CAMMESA
Value of data applied for the purpose of calculating expected emission reductions in section B.5	This is an overwhelming amount of data. For a summary view, please refer to the spreadsheet “PP’s Calculation of OM 2011.xlsb”, and for a detailed view of hourly calculations, month by month, please refer to the following files: - January 2011: “OM 2011 day by day 012011.xlsb” - February 2011: “OM 2011 day by day 022011.xlsb” - March 2011: “OM 2011 day by day 032011.xlsb” - April 2011: “OM 2011 day by day 042011.xlsb” - May 2011: “OM 2011 day by day 052011.xlsb” - June 2011: “OM 2011 day by day 062011.xlsb” - July 2011: “OM 2011 day by day 072011.xlsb” - August 2011: “OM 2011 day by day 082011.xlsb” - September 2011: “OM 2011 day by day 092011.xlsb” - October 2011: “OM 2011 day by day 102011.xlsb” - November 2011: “OM 2011 day by day 112011.xlsb” - December 2011: “OM 2011 day by day 122011.xlsb”
Description of measurement methods and procedures to be applied:	Data published by CAMMESA; measurements are taken by the generators and by CAMMESA through SMEC every 15 minutes, whose information is received remotely by CAMMESA
QA/QC procedures to be applied:	It is strictly controlled by CAMMESA in order to guarantee market prices and transparency
Any comment:	Total hourly generation of the top 10% of marginal power plants provided by CAMMESA will be downloaded to the spreadsheet tool for operating margin calculation, carried out by Project Participant (This is an overwhelming amount of data. For a summary view, please refer to the spreadsheet “PP’s Calculation of OM 2011.xlsb”, and for a detailed view of hourly calculations, month by month, please refer to the following files: - January 2011: “OM 2011 day by day 012011.xlsb” - February 2011: “OM 2011 day by day 022011.xlsb” - March 2011: “OM 2011 day by day 032011.xlsb”

	- April 2011: "OM 2011 day by day 042011.xlsb" - May 2011: "OM 2011 day by day 052011.xlsb" - June 2011: "OM 2011 day by day 062011.xlsb" - July 2011: "OM 2011 day by day 072011.xlsb" - August 2011: "OM 2011 day by day 082011.xlsb" - September 2011: "OM 2011 day by day 092011.xlsb" - October 2011: "OM 2011 day by day 102011.xlsb" - November 2011: "OM 2011 day by day 112011.xlsb" - December 2011: "OM 2011 day by day 122011.xlsb")

Data / Parameter:	$FC_{i,n,h}$
Data unit:	Mass or volume unit
Description:	Amount of fossil fuel type *i* consumed by grid power unit *n* in hour *h*
Source of data to be used:	CAMMESA
Value of data applied for the purpose of calculating expected emission reductions in section B.5	This is an overwhelming amount of data. See spreadsheets: - January 2011: "OM 2011 day by day 012011.xlsb" - February 2011: "OM 2011 day by day 022011.xlsb" - March 2011: "OM 2011 day by day 032011.xlsb" - April 2011: "OM 2011 day by day 042011.xlsb" - May 2011: "OM 2011 day by day 052011.xlsb" - June 2011: "OM 2011 day by day 062011.xlsb" - July 2011: "OM 2011 day by day 072011.xlsb" - August 2011: "OM 2011 day by day 082011.xlsb" - September 2011: "OM 2011 day by day 092011.xlsb" - October 2011: "OM 2011 day by day 102011.xlsb" - November 2011: "OM 2011 day by day 112011.xlsb" - December 2011: "OM 2011 day by day 122011.xlsb"
Description of measurement methods and procedures to be applied:	Data measured and provided by the power generators through a daily affidavit to CAMMESA
QA/QC procedures to be applied:	It is controlled by CAMMESA through national agencies and cross-checked by fuel distributors. Measurements of liquid fuels are audited by third parties hired by CAMMESA and measurements of natural gas are audited by the suppliers
Any comment:	Total hourly consumption by type of fossil fuel of the top 10% of marginal power plants provided by CAMMESA will be downloaded to the spreadsheet tool for operating margin calculation, carried out by Project Participant (This is an overwhelming amount of data. See spreadsheets: - January 2011: "OM 2011 day by day 012011.xlsb" - February 2011: "OM 2011 day by day 022011.xlsb" - March 2011: "OM 2011 day by day 032011.xlsb" - April 2011: "OM 2011 day by day 042011.xlsb" - May 2011: "OM 2011 day by day 052011.xlsb" - June 2011: "OM 2011 day by day 062011.xlsb" - July 2011: "OM 2011 day by day 072011.xlsb" - August 2011: "OM 2011 day by day 082011.xlsb"

	- September 2011: "OM 2011 day by day 092011.xlsb" - October 2011: "OM 2011 day by day 102011.xlsb" - November 2011: "OM 2011 day by day 112011.xlsb" - December 2011: "OM 2011 day by day 122011.xlsb")

Data / Parameter:	$EF_{CO2,i,y}$
Data unit:	tCO_2/GJ
Description:	CO_2 emission factor of fossil fuel type *i* in year *y*
Source of data to be used:	According to the first option for CO_2 emission factor of fossil fuel of the 'Tool to calculate the emission factor for an electricity system', ver. 02.2.1, values would be provided by the fuel supplier of the power plant in invoices, in case data is collected from power plant operators. If not, according to the second option of said Tool, values would be provided from regional or national average default values. If not, according to the third option of said Tool, values would be provided from IPCC default values at the lower limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories. At the current moment, the Project Participant expects that the data source available would be provided from the Secretariat of Energy and National Communications of Argentina to the UNFCCC (currently this is the 2nd Nat. Comm., GHG Inventory 2000, p. 197; Sept. 2005) emission factors
Value of data applied for the purpose of calculating expected emission reductions in section B.5	**Fuel** / **Emission factor (tCO_2/GJ)** Natural gas: 0.056140 Fuel oil: 0.077926 Gasoil (Diesel): 0.074354 Mineral coal: 0.094509 Values provided by the Secretariat of Energy and National Communications of Argentina to the UNFCCC (currently this is the 2nd Nat. Comm., GHG Inventory 2000, p. 197; Sept. 2005) emission factors
Description of measurement methods and procedures to be applied:	This data is monitored yearly to identify occasional updates; emission factors informed by the government were calculated from chromatography analysis of the fuels
QA/QC procedures to be applied:	National values are compared with IPCC default values to ensure they fall into the 95% confidence interval as provided in Table 1.4 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories
Any comment:	

Data / Parameter:	$NCV_{i,y}$
Data unit:	GJ/mass or volume unit
Description:	Net calorific value (energy content) of fossil fuel type *i* in year *y*
Source of data to be used:	According to the first option for net calorific value (energy content) of the 'Tool to calculate the emission factor for an electricity system', ver. 02.2.1, values would be provided by the fuel supplier of the power plant in invoices, in case data is

<table>
<tr><td></td><td>collected from power plant operators. If not, according to the second option of said Tool, values would be provided from regional or national average default values. If not, according to the third option of said Tool, values would be provided from IPCC default values at the lower limit of the uncertainty at a 95% confidence interval as provided in table 1.2 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories.
At the current moment, the Project Participant selects data provided by the Secretariat of Energy, which is used in the National Communications of Argentina to the UNFCCC (currently this is the 2nd Nat. Comm., GHG Inventory 2000, p. 197; Sept. 2005)</td></tr>
<tr><td>Value of data applied for the purpose of calculating expected emission reductions in section B.5</td><td><table><tr><th>Fuel</th><th>NCV (GJ/tonne)</th></tr><tr><td>Natural gas</td><td>48.33</td></tr><tr><td>Fuel oil</td><td>41.03</td></tr><tr><td>Gasoil (Diesel)</td><td>42.71</td></tr><tr><td>Mineral coal</td><td>24.70</td></tr></table>Values provided by the Secretariat of Energy, taken from the National Communications of Argentina to the UNFCCC (currently this is the 2nd Nat. Comm., GHG Inventory 2000, p. 197; Sept. 2005)</td></tr>
<tr><td>Description of measurement methods and procedures to be applied:</td><td>This data is monitored for eventual updates (fuel providers include higher heating values measured by them in the invoices)</td></tr>
<tr><td>QA/QC procedures to be applied:</td><td>National values are compared with IPCC default values to ensure they fall into the 95% confidence interval as provided in Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories</td></tr>
<tr><td>Any comment:</td><td></td></tr>
</table>

Data to be monitored for calculating Project emissions from fuel combustion:

<table>
<tr><td>Data / Parameter:</td><td>$NCV_{i,y}$</td></tr>
<tr><td>Data unit:</td><td>GJ/tonne</td></tr>
<tr><td>Description:</td><td>Average net calorific value of natural gas combusted in year y</td></tr>
<tr><td>Source of data to be used:</td><td>According to option (a) for net calorific value of the Methodology ACM0007, ver. 06.1.0, values would be provided by the fuel supplier in invoices. If option (a) is not available, according to said Methodology, values would be provided from:
- Option (b): measurements by Project Participant
- Option (c): regional or national default values based on well documented, reliable sources
- Option (d): IPCC default values at the lower limit of the uncertainty at a 95% confidence interval as provided in Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories
At the current moment, the Project Participant expects that the data source available would be provided from chromatography data provided by the fuel supplier. These data is provided in the monthly quality and delivery certificate</td></tr>
<tr><td>Value of data</td><td>47.93 (estimated as the average value of the period 2008-2010 from</td></tr>
</table>

applied for the purpose of calculating expected emission reductions in section B.5	chromatography data provided by the fuel supplier)
Description of measurement methods and procedures to be applied:	Values calculated from chromatography data provided by the fuel supplier. Measurements undertaken by the supplier through chromatography analysis are in line with international fuel standards
QA/QC procedures to be applied:	It will be verified that the values are within the uncertainty range of the IPCC default values as provided in Table 1.2, Vol.2 of the 2006 IPCC Guidelines. If the values fall below this range additional information from the testing laboratory will be collected to justify the outcome or conduct additional measurements
Any comment:	The laboratory complies with international quality standards

Data / Parameter:	$EF_{CO2,i,y}$
Data unit:	tCO_2/GJ
Description:	Weighted average of CO_2 emission factor of natural gas combusted in year *y*
Source of data to be used:	According to option (a) for CO_2 emission factor of the Methodology ACM0007, ver. 06.1.0, values would be provided by the fuel supplier in invoices. If option (a) is not available, according to said Methodology, values would be provided from: - Option (b): measurements by Project Participant - Option (c): regional or national default values based on well-documented, reliable sources - Option (d): IPCC default values at the upper limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories Data source required by said Methodology is compatible with the required by the 'Tool to calculate the emission factor for an electricity system', ver. 02.2.1. At the current moment, the Project Participant expects that the data source available would be provided from fuel supplier
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.05547 (estimated as the average value of the period 2008-2010 from chromatography data provided by the fuel supplier)

Description of measurement methods and procedures to be applied:	Calculated from data provided by the fuel supplier. Measurements are undertaken in line with national and international fuel standards. Chromatography samples are taken by the fuel provider
QA/QC procedures to be applied:	The values are within the uncertainty range of the IPCC default values as provided in Table 1.2, Vol.4 of the 2006 IPCC Guidelines

Any comment:	The laboratory follows international standards

Data / parameter:	$FC_{ST,DO,y}$
Data unit:	Tonne/year
Description:	Quantity of diesel oil used by the Emergency Project power unit (GE SSAA TV) in year *y*
Source of data to be used:	Measurement with electronic level sensor
Value of data applied for the purpose of calculating expected emission reductions in section B.5:	1.5708
Description of measurement methods and procedures to be applied:	The daily tank has a level meter with transmitter that connects the PLC, which will perform the flow calculations. The information is available on the DCS control room. For the monitoring plan the monthly record will be used
QA/QC procedures to be applied:	The consistency of the measured gas oil consumed will be cross-checked with the product of the hours on services of emergency power unit (GE SSAA TV) in year y times the hourly specific fuel consumption of the equipment. The accuracy of level meter systems is +/- 2% deviation from the range of measuring value. The calibration frequency is executed yearly
Any comment:	

Data / Parameter:	$NCV_{ST,DO,y}$
Data unit:	GJ/tonne
Description:	Average net calorific value of diesel oil used by the Emergency Project power unit (GE SSAA TV) in year y
Source of data to be used:	According to option (a) for liquid fuels of the 'Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion', ver. 02, values would be provided by the fuel supplier in invoices. If not, according to option (b) of said Tool, values would be provided from measurements by Project Participant. If not, according to option (c) of said Tool, values would be provided from regional or national default values. At the current moment, the Project Participant expects that the data source available would be provided from regional or national default values

Value of data applied for the purpose of calculating expected emission reductions in section B.5:	42.71, value provided from regional or national default values
Description of measurement methods and procedures to be applied:	The monitoring frequency of this parameter is annual
QA/QC procedures to be applied:	National values are compared with IPCC default values to ensure they fall into the 95% confidence interval as provided in Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories
Any comment:	

Data / Parameter:	$EF_{CO2,DO,y}$
Data unit:	tCO_2/GJ
Description:	Weighted average CO_2 emission factor of diesel oil in year y
Source of data to be used:	According to option (a) for liquid fuels of the 'Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion', ver. 02, values would be provided by the fuel supplier in invoices. If not, according to option (b) of said Tool, values would be provided from measurements by Project Participant. If not, according to option (c) of said Tool, values would be provided from regional or national default values. At the current moment, the Project Participant expects that the data source available would be provided from regional or national default values
Value of data applied for the purpose of calculating expected emission reductions in section B.5:	0.074354, value provided from regional or national default values
Description of measurement methods and procedures to be applied:	The monitoring frequency of this parameter is annual
QA/QC procedures to be applied:	The values are within the uncertainty range of the IPCC default values as provided in Table 1.2, Vol.4 of the 2006 IPCC Guidelines
Any comment:	

B.7.2. Description of the monitoring plan:

The monitoring plan details the actions necessary to record all the variables and factors required by the methodology, as detailed in section B.7.1 above. All data will be archived electronically, and backed up regularly. Moreover, it will be kept for the full crediting period, plus two years after the end of the last crediting period or the last issuance of CERs for this Project activity (whichever occurs later).

Loma de la Lata has in place quality (ISO 9001) and environmental (ISO 14001) management systems in order to achieve the company goals and furthermore improve the effectiveness and efficiency of its processes.

The systems implemented evidence the concern and experience of the Project developer in the implementation and management of very demanding control systems, and consequently in the monitoring of them to ensure the quality of the process.

The skilled personnel designated for the operation of the plant will receive training from the engineering provider.

Additionally, an external CDM consultant will provide training on CDM monitoring requirements and data recording and reporting to guarantee the awareness and commitment of the personnel to monitor the required data for the entire crediting period. The CDM assessor will be responsible for the calculations according to the methodology and of any required updates due to future changes in the methodology.

The responsibilities and duties of the personnel regarding data collection, calibration of monitoring equipment, maintenance of monitoring equipment and installations, and record are established and documented in the following tables:

Measurement of Natural Gas							Contrast of Measurement Equipment				
Variable	Gas meter	Frequency	Responsible	Result	QA/QC	Record	Calibration	Frequency	Responsible	Record	Flow
Natural gas consumption in m3/month	Two orifice plates from supplier (YPF) and differential pressure transmitters	Continuous, monthly value recorded, consisting of the daily sum	Shift Manager of CTLLL Head of Operations of CTLLL Plant General Manager of CTLLL	Value on the provider's monthly records	Check with provider bills when available; comparing with CAMMESA registires; making an annual mass balance; daily monitoring of TG efficiency and own flow meters	Monthly reports in digital and physical format in the plant and digital copies recorded by the COG	According to "Natural gas measuring protocol"	Orificie Plates: annual Computer system: quarterly	Instrumentation and Control Operations Chief CTLLL Plant General Manager CTLLL	Calibration certificates of instruments and sample patterns Records of calibration of measuring equipment	Provider (YPF) to CTLLL --> Physical copy left in the plant --> Digital image storaged by COG
Chromatography data of natural gas composition	Cromatograph of supplier (YPF)	Continuous, monthly average of the daily average recorded	Shift Manager of CTLLL Head of Operations of CTLLL Plant General Manager of CTLLL	Value on the provider's monthly record	Check with IPCC default ranges	Monthly reports in digital and physical format in the plant and digital copies recorded by the COG	Contrast with target gas by supplier (YPF)	Cromatograph: monthly	Instrumentation and Control Operations Chief CTLLL Plant General Manager CTLLL	Calibration Certificates	Provider (YPF) to CTLLL --> Physical copy left in the plant --> Digital image storaged by COG

Measurement of Net Energy Generated							Contrast of Measurement Equipment				
Variable	Power Meter	Frequency	Responsible	Result	QA/QC	Record	Calibration	Frequency	Responsible	Record	Flow
Energy Generated by CTLLL in MWh/h	SMEC	Measured continuously (recorded every 15 minutes) with SMEC; the value monitored and used for caluclations is the one registered by CAMMESA on a daily or monthly basis from daily post operative reports including hourly data	Shift Manager of CTLLL COG and SC of Pampa Energía, Plant General Manager of CTLLL	Hourly data post-operative report by CAMMESA	Check with the grid energy balance, energy billing and own readings of SMEC	Post - operative monthly value of CAMMESA archived in digital format	Transener contrast or a third party hired by CAMMESA following "Procedures"	Annual contrast and calibration when is necessary by Transener Randomly CAMMESA hires personnel to check the equipment. For the equipment for MEGA gas processing plant the calibration frequency is determinated by CAMMESA, and is executed anually.	Head of Electrical Maintenance CTLLL Plant General Manager CTLLL	Calibration certificates of instruments used in the verification and calibration records of meters	From Plant to COG keeping it digitally

Measurement of liters of diesel oil							Contrast of Measurement Equipment				
Variable	Power Meter	Frequency	Responsible	Result	QA/QC	Record	Calibration	Frequency	Responsible	Record	Flow
Consumption of diesel oil of Genset Auxiliary Services of Steam Turbine	Level meter and PLC	Monthly	Shift Manager of CTLLL COG and SC of Pampa Energía, Plant General Manager of CTLLL	Liters of diesel oil converted to tonnes with 0,000845 tonnes/liters	Routine maintenance record and be cross-checked with The consistency of the measured gas oil consumed will be cross-checked with the product of the hours on services of emergency power unit (GE SSAA TV) in year y times the hourly specific fuel consumption of the equipment	It records the result of measurement	Plant Maintenance Personnel	The calibration frequency is executed anually	Head of Maintenance of CTLLL, Shift Manager of CTLLL, Plant General Manager of CTLLL	Maintenance record	From Plant to COG keeping it digitally

The Plant General Manager of CTLLL is the responsible for the review and reporting of the CDM project.

A specific monitoring plan for the CDM project has been designed. A Spanish version of this monitoring plan is used by all responsible of the different tasks identified in tables above. A copy of this plan is shown to the DOE validating the Project.

Natural gas

The specific functions of gas consumption measurements is performed by the gas supplier based on a Protocol on Natural Gas Measurement Transfer Point[55], supervised and managed by an Operating Committee composed of both companies (natural gas supplier and Central Térmica Loma de la Lata), which verifies its strict compliance.

Measurement activities and equipment contrast, the frequency of execution, equipment used and the implementing rules are spelled out in the Protocol.

The equipment used in the measuring point No. 81 (Loma de la Lata, Neuquén) belonging to the natural gas supplier, where volume reading and sampling are taken, calorific value, relative density, composition and the corresponding chromatographic processing necessary to obtain the corrected volume are taken, can be summarized as follows:

- Reading volume (flow) through orifice meters that operate a gas volume computer system brand Floboss Fisher Rosemount Model ROC407.
- For the determination of chemical composition, calorific value, relative density and the compressibility factor an on-line chromatograph Baker brand, model 6840 connected to the computer system is used.
- Standards considered by the protocol are AGA Report No. 3 for orifice plate holder and API system and "Flow Measurement using electronic metering systems" MPMS Chapter 21 Section 1 Electronic Gas Measurement for electronic equipment.

Every month a third party company hired by the natural gas supplier verifies the chromatograph using a standard gas for contrast by taking three samples. In case deviations are out of admissible range according to the class of the equipment, then the equipment is calibrated. In case that after three years it was not necessary to calibrate the equipment according to this procedure, calibration will take place anyway. Personnel of Central Térmica Loma de la Lata participate in the verification.

Differential pressure transmitters are contrasted by the same third party (it is the same for all measurement related to natural gas) every three months with the participation of Central Térmica Loma de la Lata personnel. Orifice plates are contrasted yearly. The diameters of the plates are verified, since those values are used as constants in the fuel meters. Again, in case deviations are out of admissible range according to the class of the equipment, then the equipment is calibrated. In case after three years it was not necessary to calibrate the equipment according to this procedure, calibration will take place anyway.

Values used for calculations are those recorded in paper in the monthly quality and delivery certificate, signed by the fuel supplier and by the General Manager and the Operation Chief of the power plant, since it is the basis for natural gas purchases.

Electricity generation

The process of measuring the net electricity generated by the plant and delivered to the grid is taken with

[55] The calibration frequency described in the monitoring plan corresponds to a revised version of said Protocol, which is pending of signature.

the SMEC (Commercial Measurement System) following the protocols of CAMMESA (The Procedures) for this purpose. There are 9 SMECs in the power plant. 8 of these SMECs are owned by Central Térmica Loma de la Lata (CTLLL) and one of them is owned by MEGA, a gas processing plant that has been supplied by the gas turbine #1 prior to the acquisition of Loma de la Lata power plant by Pampa Energía. This continues being the case so that the electricity generated by gas turbine #1 is measured by adding the corresponding CTLLL SMECs (primary and, eventually, secondary) and the MEGA SMEC.

Measurement activities and their QA/QC procedures are established in The Procedures.

The equipment for this function is Schlumberger and Circutor brand. Each SMEC is redundant since two measuring units are installed (per measuring point), except for the SMEC owned by MEGA company.

Following ISO 9001 standard, the power plant verifies every year the SMECs. SMECs are sealed in order to protect commercial measurements. Every year Central Térmica Loma de la Lata informs CAMMESA the opening of the seals and verifies equipment. In case deviations are out of admissible range according to the class of the equipment, then the equipment is calibrated by the electricity transportation company. After verification CAMMESA goes to the site to seal SMECs again. On the other hand, CAMMESA sends randomly a contracted company to verify SMECs. In case after three years it was not necessary to calibrate the equipment according to this procedure, calibration will take place anyway.

Values used for emission calculations are those extracted by CAMMESA from SMECs.

Once a year, through the SAP system, the Maintenance Department is informed about the verification of the SMECs. Reports with the results and certificates of the calibrated equipment used for contrasting are recorded.

Diesel oil

Diesel oil consumption by emergency equipment for auxiliary services of the steam turbine is measured with a level meter during the monitoring period assuming. The daily tank has a level transmitter that connects the PLC. The PLC will perform the flow calculations. The information is available on the DCS control room. For monitoring plan the monthly record will be used. The consistency of metered gas oil consumed will be cross-checked with the product of the hours on services of emergency power unit (GE SSAA TV) in year y times the hourly specific fuel consumption of the equipment. The accuracy of Level Meter systems is +/- 2% deviation from the range of measuring value. The calibration frequency is annual.

All the information, the daily consumption of gas, the power generation in each hour and the Diesel equipment consumption, will be stored digitally for two years more than the duration of the whole crediting period.

During the registration process of these variables, when there are scheduled stops or following clearance requirement, they are logged into the same databases that make up the historical archives of operation of the plant.

The information generated by CAMMESA[56] in relation to the energy generated in MWh, technology, and the amount and type of fuel used as well as the hourly emission factor provided by the Secretariat of Energy[57] is loaded into the power plant digital archives.

At the same time the monitoring and recording of pollutant emissions and effluent discharge in the Lake Mari Menuco is done according to protocols agreed and approved for such purpose by the implementing authorities. However, this monitoring will not form part of the CDM verification process.

Figure 5 shows the monitoring/measurement points of all parameters involved in the monitoring plan.

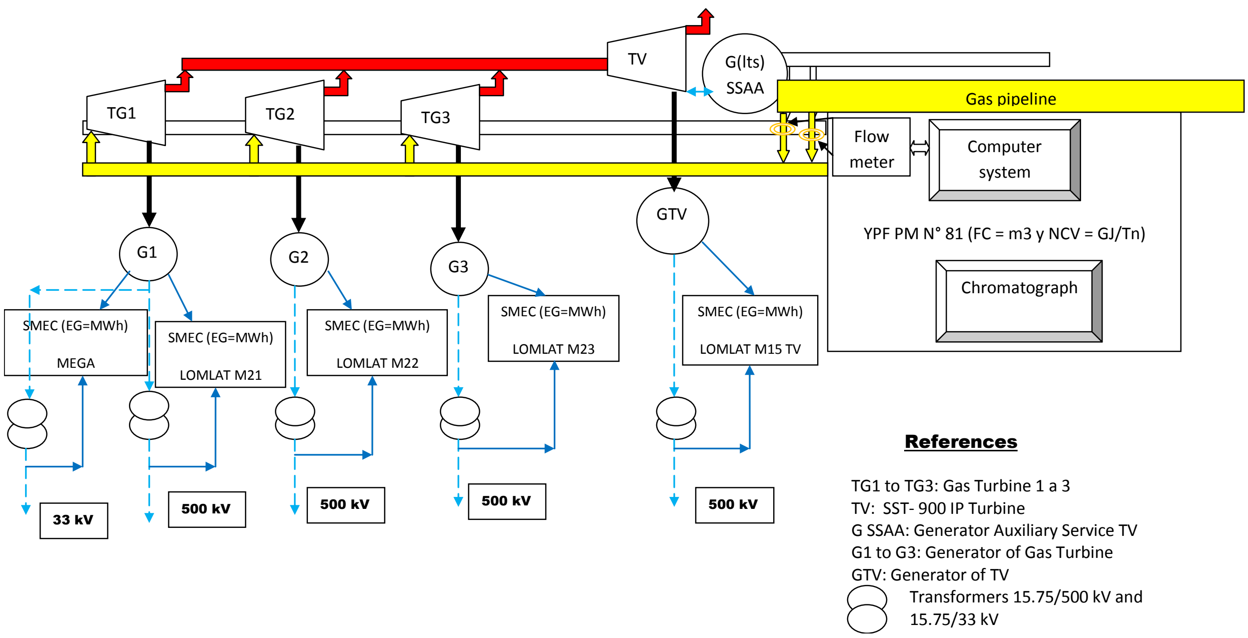

Figure 5: Monitoring/measurement points

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

The application of the baseline study and monitoring methodology was completed on November 29, 2011. The carbon advisors are Hugo Ventureira and Fabián Gaioli (they are not Project participants).

[56] Each day from the CAMMESA website: http://memnet2.cammesa.com/inicio.nsf/marcomemnet

[57] http://energia3.mecon.gov.ar/contenidos/verpagina.php?idpagina=2311.

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:

06/09/2007

Signing of the contract between Pampa Energía S.A. and Isolux - Corsán for the design, engineering, equipments provision, installation, civil works and tests required for the Conversion of Loma de la Lata to Combined Cycle.

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

38 years 0 months[58]

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:

01/09/2012 or CDM Project registration date (whichever occurs later)

C.2.1.2. Length of the first crediting period:

7 years 0 months

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

Not applicable

C.2.2.2. Length:

Not applicable

[58] The remaining lifetime of the gas turbines rotors (prior to its replacement). Please refer to section B.2.

SECTION D. Environmental impacts

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

Environmental matters in Argentina are jurisdiction of the Provincial Governments. In this regard, the Government of Neuquén established the Law Nº 1,875 (T.O. Ley Nº 2,267) about the preservation, conservation, defence and improvement of the environment in all the territory of the Province of Neuquén, to achieve and maintain an optimum quality of life of its inhabitants. The law states (Art. 24) that every Project that due to its size or characteristic could modify the environment, must have, as previous requirement for its execution, the Declaration of Environmental Impact and its corresponding Environmental Management Plan approved by the corresponding authority.

Furthermore, the Decree Nº 2,656, regulatory of the mentioned law, establishes (Art. 24) the obligation of the Project proponents to present to the corresponding authority - previous to the starting date of any activity - an Environmental Report or an Environmental Impact Assessment. In these documents the proponent has to make a Declaration of the Environmental Impact and has to detail the Environmental Management Plan that is committed to implement in every stage of the Project.

The Environmental Impact Assessment (EIA) of the Project activity has been elaborated by the Regional School of Avellaneda of the National Technological University of Argentina. This document was presented to the National Regulator Entity of Electricity (ENRE) which released a positive review on May 22, 2008. At the provincial level, the EIA was submitted to the Sub-Secretariat of Environment, of the State Secretariat of Environmental Resources of the Provincial Government of Neuquén (SSMADS).

The SSMA had required dividing the EIA in sections to approve the project. In this context the EIA of Combined Cycle was divided in two stages:

Stage 1: Civil and electromechanical construction inside of Loma de la Lata land. This phase was approved by the mentioned authority who conceded the Environmental License for the Construction of the Combined-Cycle through the Disposition Nº 387/2008 on 21 July 2008.

Addenda Stage 1: Extension of Field 02 and Transformer Station 500 kV. Approved by SSMA with Environmental License through the Disposition N° 039/09 on 17 February 2009.

Stage 2: aqueducts, water intake and effluent discharge. This phase was approved by SSMA through the Disposition N° 435/09 on 31 July 2009.

The request of SSMADS has been fulfilled accordingly to the competent authorities, as is reflected from the following notes:

Note ENRE 84201- Accepting the Stage 1 Civil and electromechanical construction inside of Loma de la Lata land.

Note ENRE 88,139 - Accepting the Stage 2 aqueducts, water intake and effluent discharge.

The permissions to water intake and effluent discharge into Mari Menuco Lake was conceded by the Provincial Direction of Water Resources (DPRH) through the following Dispositions:

- Disposition 202/09 DPRH on 29 December 2009. DPRH granted the permission to water intake.
- Disposition 203/09 DPRH on 29 December 2009 construction works of water intake and effluent discharge into the reservoir Mari Menuco were validated.
- Disposition 0030/10 DPRH on 15 March 2010 emitted an authorization of effluent discharge.

In general, the outcome of the EIA was favourable and the Project was not found to have permanent environmental or social negative impacts overall. The main negative impacts of the Project outlined at the EIA are related to the operation phase and are summarized in the table 8.

Table 8: Environmental and social impacts (taken from EIA)

Possible Impacts	Impact Nature	Magnitude	Mitigation Actions Level	Impact Relevancy	Prevention Action
Landscape Alterations	Negative	Small	Medium	Small	Re-plantation Plan of native vegetation species
Noise level	Negative	Small	High	Small	Monitoring
Alterations Mari Manuco Lakes	Negative	High	High	High	Wastewater treatment system and Monitoring
Employment generation	Positive	Medium	Medium	Medium	Contract local employees
Increase of power installed capacity	Positive	High	High	High	Increase power capacity available to supply electricity to the Argentine System of Interconnection (SADI)
Minimization of Nitrous Oxides emissions per MWh generated	Positive	Small	Medium	Small	-
Energy Matrix alteration	Positive	High	-	High	-
Decrease vulnerability in energy offer	Positive	High	-	High	-

A copy of the EIA report will be provided to the Designated Operational Entity (DOE) validating the Project.

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

With mitigation controls planned as part of the Project design, construction and operation according to the recommendations of the EIA, and the contribution made by the Project to sustainable development at local and national scales, the Project is expected to have an overall positive impact on the local and global

environment. The significant negative environmental impacts are subject to mitigation and monitoring measures as described next.

- Speed measurement and bathymetry in Los Barreales and Mari Menuco Lakes. This determination was realized by EVARSA in October 2008.
- Effluent discharge Evaluation in Mari Menuco Lake. This study was made by EVARSA in March 2009.
- Environmental Data Base of Mari Menuco Lake. This research was made by Monitoreos Ambientales in October 2010.
- Permanent control of waste water treatment.

An important mitigation action is the use of the effluent to irrigate a wine plantation. This Project required an Environmental Information called Addenda "Viñedos PAMPA"- CTLLL. The report was realized by GAMA CONSULTORS in February 2010. This Project was approved by SSMA firstly on March 30, 2010 (Disposition 112/10-revoked because of the change in the name of the company of Central Térmica Loma de la Lata previously known as Pampa Energía) and then by means of Disposition 247/11 on 22 June 2011.

In this regard, as evidenced by Resolution No.030/10, the Project was granted permission to discharge effluents in Lake Mari Menuco and established a plan for monitoring them.

Monitoring Activities established by Disposition DPRH 030/10, include:

1. Monthly monitoring of Mari Menuco Lake
2. Monthly monitoring of effluent by an external laboratory
3. Weekly monitoring of effluent in plant
4. Continuous measurement of temperature, pH, conductivity and oil in effluents

Additionally, the Project developer implemented social and healthcare programs, some monitoring programs in line with the State Environment Agency, and some environmental programs, such as environmental education, degraded area recuperation and investments in ecological reserves.

SECTION E. Stakeholders' comments

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

In November 2008 Pampa Energía S.A. originally decided to publish details of the Project on a website and to invite the following local stakeholders through e-mails and letters to make comments:

- National and local environmental and energy authorities (Secretariat of Energy, Secretariat of Institutional Affairs of Neuquén, Under-Secretariat of Environment of the Neuquén Province, Electric Energy Federal Council – CFEE, Gas Regulation National Entity – ENARGAS, Energy Entity of Neuquén Province – EPEN, Electricity Regulation National Entity – ENRE);
- Local and national media (La Mañana Neuquén, Neuquén Online, Río Negro Online, Soloenergia.com.ar);
- Academia (Universidad Nacional del Comahue);

- Industry associations representatives (CAMMESA, Large Users of Electric Energy Association of Argentina – AGUEERA, Electric Energy Distributors Association of Argentina – ADEERA, Electric Energy Generators Association of Argentina – AGEERA);
- NGOs (Fundación Ambiente y Recursos Naturales, Fundación Bariloche, Conservación Patagónica);
- Local community associations (Patagonia Business Foundation – FEPAT, Centre of Applied Ecology of Neuquén);

The stakeholders were invited to raise their concerns and provide comments on the Project activity.

Answers received are summarized in the last three rows of table 9.

A new set of stakeholders was selected and invited to answer specific questions of notes sent by electronic and postal mail in November 2011. Specifically the questions addressed the following issues:

- General opinion about the Project.
- Opinion about the contribution to sustainable development of Argentina and the region where the Project is implemented.
- Additional comments and concerns.

Stakeholders invited to participate in November 2011, included:

- Gas y Petróleo Neuquén (Ing. Alfredo Barber),
- Universidad Nacional del Comahue (Lic. Graciela Silva),
- Comisión Interdisciplinaria de Medio Ambiental -CIMA (Miguel Angel Rementeria)

Next section summarizes the comments received in the two first rows of table 9 and actions taken.

E.2. Summary of the comments received:

Table 9 shows a synthesis of the responses given by stakeholders to the consultation.

Table 9: Stakeholder comments

Stakeholder	General opinion	Sustainable development opinion	Additional comments	Consultation
Gas y Petróleo del Neuquén S.A.	The Project has the proposed advantages.	The Project contributes indirectly to the sustainable development until the renewable energy market can be developed. It also provides some labor positions during implementation stage.	It is interesting to know whether local technology is used or technology transfer has happened.	Second Consultation
Environmental Interdisciplinary Commission (CIMA)	The Project contributes to increase installed capacity in a context of no private investments.	The Project contributes to the sustainable development due to the fact that the steam turbine does not require additional fuel.	It is interesting to know whether the Project has an environmental management plan.	Second Consultation

Stakeholder	General opinion	Sustainable development opinion	Additional comments	Consultation
Electric Energy Distributors Association of Argentina (ADEERA)	The Project contributes to the sustainable development. The Association supports the positioning of an Argentine company in the Kyoto Protocol.			First Consultation
Electric Energy Generators Association of Argentina (AGEERA)	The Project contributes to the sustainable development due to: • Preservation of natural resources due to the reduction in gas consumption • Lowering the thermal impact due to the reduction of exhaust gas temperature • Reduction of CO_2 emissions per MWh • Reduction of NO_x emissions per MWh • Increasing installed capacity to the SADI			First Consultation
Patagonia Business Foundation (FEPAT)	The Foundation supports the Project due to the contribution to mitigate global warming. The Project should be replicated to contribute to a sustainable growth.			First Consultation

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

Central Térmica Loma de la Lata responded by e-mail to two of the stakeholder’s concerns, Neuquén O&G S.A. regarding technology transfer and CIMA regarding the environmental management plan. The explanations are already contained in the present PDD (sections A.2 and D.1, respectively).

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	Central Térmica Loma de la Lata S.A.
Street/P.O.Box:	Ortiz de Ocampo 3302
Building:	Building 4
City:	Buenos Aires
State/Region:	Autonomous City of Buenos Aires
Postfix/ZIP:	C1425DSR
Country:	Argentina
Telephone:	(+5411) 4809-9500
FAX:	(+5411) 4809-9600
E-Mail:	mdl@pampaenergia.com
URL:	www.pampaenergia.com
Represented by:	
Title:	President
Salutation:	Mr.
Last Name:	Mindlin
Middle Name:	Marcelo
First Name:	Marcos
Department:	-
Mobile:	-
Direct FAX:	-
Direct tel:	-
Personal E-Mail:	-

Annex 2

INFORMATION REGARDING PUBLIC FUNDING

This Project will not receive any public funding from Annex 1 parties.

Annex 3

BASELINE INFORMATION

Investment analysis

The most suitable financial indicator for the benchmark analysis is the Internal Rate of Return (IRR). The IRR is the annualized effective compounded return rate which can be earned on the invested capital, i.e. the yield on the investment. A project is considered a good investment proposition if it's IRR is greater than the rate of return that could be earned by alternate investments, in this case represented by the benchmark value.

The analysis follows the prescriptions of the "Guidelines on the assessment of investment analysis", ver. 05. Therefore, the adoption of benchmark approach is suited to circumstances where the baseline does not require investment or is outside the direct control of the project developer, i.e. cases where the choice of the developer is to invest or not to invest. Once the baseline identified is the *Continuation of the current practice* (continuation of single cycle plant operation) the baseline does not present any investment barrier, given that it does not require additional investments. Hence, as per the referred guidelines "if the alternative to the project activity is the supply of electricity from a grid this is not to be considered an investment and a benchmark approach is considered appropriate".

Input values

The input values of the financial analysis presented in the PDD are supported by third-party documents or official documents issued by governmental bodies, such as the National Energy Secretariat and CAMMESA, or were provided by the Project Developer. The parameters taken from third-party documents reflect the economic situation of the Project at the time of the decision to start the Project activity.

All financial input values and data sources are presented in table A5-1.

Table A5-1: Financial data

Investment Data	Unit	Value	*Reference*
CC Loma de la Lata	U$S	190,200,000	Lump sum price Isolux 06 July 2007
Three phase power transformer 500 kV	U$S	-	Using a conservative approach it was excluded from the investment item in the financial analysis, although it is worth to mention that the Project would not work without the power transformer. This approach was applied, even though it was identified internal evidence such as ABB quotations and PP's own estimates contained in the internal benchmark comparison.
Substation Loma de la Lata 500 kV	U$S	4,194,000	Transener proposal 14 August 2007
Hydrant construction	U$S	5,110,125	Optional budgetary price MAN 06 July 2007 with ratio of 1,3627 U$$/EUR
Boiler chimney	U$S	-	Using a conservative approach it was excluded from the investment item in the financial analysis, although it worth to mention that the Project would not work without the boiler chimney. This approach was applied, even though it was identified internal evidence such as Tecna EPC agreement with Isolux and PP's own estimates contained in the internal benchmark comparison.
Primary regulator of frequency	U$S	-	Using a conservative approach it was excluded from the investment item in the financial analysis. This approach was applied, even though it was identified internal evidence such as Tecna EPC agreement with Isolux and PP's own estimates contained in the internal benchmark comparison
Progress of work per year -2	%	22%	Isolux Corsan proposal, Annex 7.2 - schedule (4 Sept. 2007)
Progress of work per year -1	%	30%	Isolux Corsan proposal, Annex 7.2 - schedule (4 Sept. 2007)
Progress of work per year 0	%	40%	Isolux Corsan proposal, Annex 7.2 - schedule (4 Sept. 2007)

Progress of work per year 1	%	8%	Isolux Corsan proposal, Annex 7.2 - schedule (4 Sept. 2007)
Input Data	**Unit**	**Value**	***Reference***
Benchmark	%	13.31%	Calculated with public information (Bloomberg, Damodaran, Buenos Aires Stock Exchange) following the Guidelines on the Assessment of Investment Analysis, EB62
Annual inflation rate	%	2.20%	Projected CPI until 2017, The Budget and Economic Outlook, Congressional Budget Office, Congress of the US, p. 79 (Aug. 2007)
Exchange rate	AR$/US$	3.153	Average exchange rate August 2007. Central Bank of Argentina; http://www.bcra.gov.ar/
Revenues	**Unit**	**Value**	***Reference***
Price of power - spot	AR$/MW-HRP	12.0	Resolution 317/2002. Based on 2.5.2.1.2 of CAMMESA Procedures (spot power remuneration)
Hours of power remuneration	hrs/week	90	Resolution 317/2002. Based on 2.5.2.1.1 of CAMMESA Procedures (spot power remuneration)
Price of energy - spot	AR$/MWh	77.3	CAMMESA hourly records monomic spot price for Loma de la Lata
Monomic price of energy	AR$/MWh	83.7	Calculated
Monomic price spot	USD/MWh	26.6	Calculated
Price of energy - "Energía Plus"	US$/MWh	26.0	Project developer. Firm 2007 Energía Plus proposal to potential client
Price of power - "Energía Plus"	US$/MWh	30.0	Project developer. Firm 2007 Energía Plus proposal to potential client
Node Factor	%	92%	Seasonal programming May-Oct 2007. Weighted nodal factor of 500 kV (31 Aug. 2007)
Incremental Costs	**Unit**	**Value**	***Reference***
Natural gas price	AR$/m3	0.21	Average Price at Plant August 2007
Natural gas price difference for old generation	AR$/m3	0.10	Calculated. Used to estimate the additional cost of gas for the Plant's historical consumption due to the need to secure gas at a higher price to be able to sell under Energía Plus contracts
Natural gas price difference for old generation	U$S/Dam3	31.13	Calculated
Natural gas price for firm long-term Contracts	AR$/m3	0.31	Developer - estimate of gas price to secure firm gas supply. Based on firm proposal of 2007 to client of Energía Plus
Natural gas price for firm long-term Contracts	U$S/Dam3	97.26	Calculated based on existing contracts
Natural gas price reference Price Energía Plus	U$S/Dam3	81.16	Project developer. Firm 2007 Energía Plus proposal to potential client
Adjustment factor	Units	0.24	Project developer. Firm 2007 Energía Plus proposal to potential client
Increase staff power plant	People	23	Book: Combined cycle power plants. Theory and design. Issued in 2006 Authors: Santiago Sabugal García y Florentino Gomez Moñux
Average cost/employee	US$/year	51,697	Project developer
Incremental Salaries	US$/year	1,189,031	Calculated
"Water" costs	AR$/year	236,520	Project developer. Calculated based on designs of water consumption and cost established by Decree 2814/1997, Decree 1671/2001 and Disposition 195/2005 DPRH, Provincia de Neuquén
Insurance	US$/year	488,078	Project developer. Estimated based on insurance 2007 increased by investment in new assets
Services ENRE costs factor	% gross income	0.3%	Project developer. Estimates based on ENRE's 2006 allocation of costs
CAMMESA costs factor	% gross income	0.1%	Project developer. Estimates based on historical Cammesa allocation of costs
Overhead	US$/MWh	0.22	Project developer
TGs Maintenance and other costs	US$/MWh	3.62	Average September 2007 Loma de la Lata declaration of CVP (variable production costs declared to CAMMESA)
TV Maintenance and other costs	U$S/MWh	4.05	Average September 2007 Güemes declaration of CVP (variable production costs declared to CAMMESA)
Management fee	% EBITDA	12.4%	Amount paid in the third quarter 2007
Taxes	**Units**	**Value**	***Reference***
Gross incomes	% of sales	1.5%	Neuquén Law Nº 1,994
Credits taxes	% of sales	0.4%	National Law Nº 25,413 and Decree N°534/2004
Debits taxes	% of purchases	0.6%	National Law Nº 25,413
Income tax	%	35%	Ministerio de Hacienda, Finanzas, Obras y Servicios Públicos, Law Nº 20,628 (article 69)

Benchmark: The benchmark rate has been developed with publicly available information. A WACC (weighted average cost of capital) based on public information has been selected as a benchmark to be compared with the Project IRR. It is calculated in nominal terms after taxes.

$$WACC = \frac{E}{C} \times k_e + \frac{D}{C} \times k_d \times (1 - T)$$

where

E = equity
D = financial debt
C = capital ($C = E + D$)
k_e = cost of equity
k_d = cost of debt
T = income tax

The cost of equity, k_e, is estimated according to the CAPM (capital asset pricing model) method as:

$$k_e = R_f + \beta \times MP$$

where

R_f = risk-free rate of interest (instrument with the lower risk in the emerging market, e.g. risk-free rate calculated as the average of the 10-year maturity US Treasury bond yield plus country risk or the average of a 10-year maturity bond yield in the emerging market)
MP = market premium
β = sensitivity of the expected excess asset returns to the expected excess market returns

Financial debt (D) is calculated from the financial statements of all the power companies listed in Argentina in the Buenos Aires stock exchange market (Merval, Mercado de Valores) ("Central Puerto" and "Central Costanera") as of 30 June 2007.[59] Equity (E) is calculated as the market capital at June 30, 2007, based on the closing price obtained from Bloomberg quotes times the number of shares. Beta (β) is taken from Bloomberg for the month prior to Project start.[60] The cost of debt (k_d) is based on the August 2007, average yield to maturity of corporate bonds of Argentine companies operating in the power sector (Transener2016 issued on December 2006 and Edenor 2017 issued on April 2006). The income tax (T) in Argentina is 35% by law 20,628. The risk-free rate (R_f) is calculated as the average of the 10-year maturity Boden 2015 (RO15) bond yield of one month prior to Project start date taken from Bloomberg. RO15 will mature by 30 Oct. 2015 (this bond was issued by the Central Bank of Argentina in 30 Oct. 2005). It is publicly traded in the Buenos Aires stock exchange and supervised by the National Securities Commission. It is the preferred market bond with the highest liquidity in the market. The market premium

[59] Financial statements available at the "Comisión Nacional de Valores": http://www.cnv.gov.ar/InfoFinan/BuscoSociedades.asp?Lang=0&TamanioSocID=0.

[60] The month prior to project start was selected since it is more representative of the increasing tendency of all parameters involved in the financial analysis.

(*MP*) is estimated as the long-term behaviour of S&P500 returns from 1928 to 2006 with respect to the risk free US Treasury bond taken from Damodaran database.[61]

Thus, the benchmark rate value is calculated as the average WACC of the power companies (for Central Puerto and Central Costanera):

$$Benchmark = 13.31\%$$

The proposed benchmark is expressed in nominal terms, after taxes and compatible for comparison with a project cash flow's IRR in nominal terms after taxes at the time of project decisions.

The parameters used in the financial model are:

- *Investment:* It is taken from a proposal submitted by Isolux Corsán on 13 July 2007. Final contracted values were greater than the ones used in the investment analysis, thus becoming conservative values.

- *Monomic price of electricity in the spot market:* It consists of two components (the price of energy and the price of capacity) and is calculated as stated below:

  Monomic price of electricity (MWh) = Energy price (MWh) + (Capacity price (MW)) × hours of capacity remuneration (hours/week)/hours per week

  The energy price value was conservatively selected as the maximum value that CAMMESA paid to Loma de la Lata single cycle during the period January-August 2007, which was 26.6 USD/MWh.
  The capacity price is also available at CAMMESA and has remained constant since 18 July 2002 according to Resolution 317/2002.

- *"Energía Plus" price:* As mentioned above, in 2006 the Secretariat of Energy launched the "Energía Plus" Program which established that all large users should contract the difference between their current demand and their demand in the year 2005 in the "Energía Plus" market. In this new market, only energy produced from new generation plants will be traded.
  Therefore, the electricity generated by Loma de la Lata new steam turbine would be able to be sold on this new market.

  By the time the Project Participant evaluated the Project there were no public references regarding the price of the electricity in the "Energía Plus" market. The Project participant determined a price of 26 USD/MWh for the energy and 30 USD/MWh for the capacity under this market, based on a firm proposal made by the Project participant to a potential client in September 3, 2007. These prices were later confirmed by the approval of the first Energía Plus contract (Secretariat of Energy Note Nº 0625, June 26, 2008).

- *Natural gas price:* To be able to sell under the Energía Plus market the Project participant needs to have firm long-term natural gas contracts. The natural gas consumed prior to the implementation of the Project activity was bought on a short-term basis. The Project participant submitted a bid to acquire all of its natural gas requirements at the historical short-term price, which resulted in no offers

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[61] http://pages.stern.nyu.edu/~adamodar/.

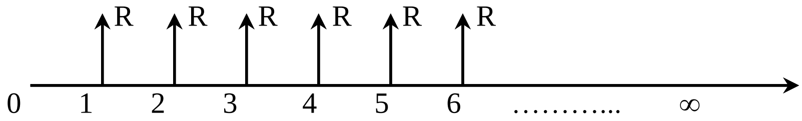
from providers at that price and term. Accordingly the price was estimated as the average price of all long-term contracts entered during August 2007.

- *Inflation rate:* As all the values are in US dollars and the economics of the Project are based on this currency, inflation was taken from “The Budget and Economic Outlook”, Congressional Budget Office, Congress of the US, (Aug. 2007), which includes a projection from 2007 to 2017 of US inflation.

- *Exchange rate:* It is obtained from the average exchange rate in August 2007, taken from the Central Bank of Argentina.

- *Fair value of assets:* The fair value has been considered using the following approach:

A perpetuity value was inserted in the end of the 20-year period analysed to correctly address the cash flow timeline. The perpetuity represents the value, in terms of present value, of all future revenues and/or costs. Using the perpetuity, the analysis considers an infinite cash flow. According to Samanez (2007) the perpetuity of a flow as shown in the figure below, can be calculated as:



$$P = R \cdot \left(\frac{1}{i} \right)$$

Where:

P	Is the perpetuity value, in terms of present value
R	Are the revenues in each year, from 0 to infinite
i	Is the relevant discount rate (the calculated benchmark)

The main hypothesis and derivation of results used in the financial model are explained in table A5-2.

Table A5-2: Investment analysis assumptions

Line Item	Description	Formula
Electricity sales spot gas turbines	Sales of the increased electricity supplied to the grid by the gas turbines due to the implementation of the Project. It is sold at the same all-in price as the rest of the gas turbine generation sold to the spot market. The spot electricity price received is adjusted by the node factor to take into consideration the cost of transportation of this electricity into the point where the spot electricity is delivered (the central node in Ezeiza) in the Argentine interconnected system. Spot price is adjusted by inflation for subsequent years.	= (increased electricity production of gas turbines [MWh]) x (spot price of the electricity [US$/MWh]) x (node factor of Project [factor w/o units])
Energy sales "Energia Plus" steam turbine	Energy component of the sales of electricity fom the steam turbine under Energia Plus contracts with large users. The project sells all of the electricity suplied to the grid by the steam turbine under Energia Plus contracts. Pass-through of increases in natural gas costs.	= (electricity supplied to the grid system by the steam turbine [MWh]) x (price of electricity under the Energia Plus contract [US$ / MWh])
Capacity sales "Energia Plus" steam turbine	Capacity component of the sales of electricity fom the steam turbine under Energia Plus contracts with large users. Price per MWh is taken from an Energi Plus contract proposal at the start date of the Project and is fixed for the life of the contract. The project sells all of the electricity suplied to the grid by the steam turbine under Energia Plus contracts.	= (electricity supplied to the grid system by the steam turbine [MWh]) x (price of capacity under the Energia Plus contract, fixed at 30.00 [US$ / MWh])
Gross income taxes	Provincial gross income tax on gross sales.	= (provincial gross income tax rate, fixed at 1.5% [%]) x (gross sales [US$])
Credits taxes	National tax on all credits.	= (national credits tax rate, fixed at 0.4% [%]) x (gross sales [US$])
Incremental natural gas cost	Cost of the incremental gas consumption due to the implementation of the Project. Cost of free gas is that of gas sold to industries. Cost of gas escaletes with inflation.	= (incremental gas consumption [m3]) x (price of free gas to industries [US$ / m3])
Incremental cost of gas turbines natural gas	Incremental cost of the gas used by the existing gas turbines prior to the implementation of the Project, as it will require to acquire all of the gas at free gas to industries prices with firm gas contracts. Cost of gas escaletes with inflation.	= (average historical gas consumption by gas turbines [m3]) x ((price of free gas to industries [US$ / m3]) - (price of gas paid by Loma at plant prior to implementation of Project [US$ / m3]))
Incremental salaries	Cost of incremental plant personnel required to operate and manage the Project. Number of incremental plant personnel based on management estimates. Costs of plant personnel based on historical costs. Salaries escalates with inflation.	
Water cannon	Cost paid by the Project for the use of water from nearby lake, according to provincial cannon fee and estimates of water ussage. Water cannon escalates with inflation	
Incremental insurance	Cost of incremental insurance to cover the new assets built for the Project. Estimated based on the insurance for the assets prior to the implementation of the Project. Insurance escalates with inflation	
Incremental ENRE services	Incremental costs paid to ENRE to cover its operational costs. Cost factor taken from ENRE's proyections.	= (incremental gross income [US$]) x (ENRE's cost factor)
Incremental CAMMESA costs	Incremental costs paid to ENRE to cover its operational costs. Cost factor taken from Cammesa's historical allocations.	= (incremental gross income [US$]) x (Cammesa's cost factor)
Incremental overhead	Cost of incremental overhead required by the implementation of the Project. Unit cost per MWh generated based on historical data at Loma. Cost escalates with inflation.	= (incrementas electricity supplied to the grid system [MWh]) x (overhead unit cost [US$ / MWh])
Incremental maintenance & other costs	Cost of incremental maintenance and operational costs due to the implementation of the Project. Costs per unit of generation taken from such cost declaration to Cammesa for Loma in relation to costs asociated with the operation of the gas turbines, and from Guemes in relation to costs asociated with the operation of the steam turbine and its auxiliaries. Cost escalates with inflation	= (electricity supplied to the grid system by the gas turbines [MWh]) x (unit cost of operation and maintenance of gas turbines [US$ / MWh]) + (electricity supplied to the grid system by the steam turbine [MWh]) x (unit cost of operation and maintenance of steam turbine [US$ / MWh])
Management fee	Management Fee for services rendered to the Project. Fee set at 12.4% of EBITDA.	= (management fee, fixed at 12.4% [%]) x (EBITDA)
Debits taxes	National tax on all payments.	= (national debit tax rate, fixed at 0.6% [%]) x (total payments [US$])

Technical input values used in the analysis are show in table A5-3.

Table A5-3: Technical data

Data / Parameter	Unit	Source of data	Valued Applied	Comments/References
Baseline				
Open Cycle Gross Installed Capacity	MW	Technology provider	369,93	Three (3) natural gas turbines General Electric PG 9171 E of 123.31 MW each one . GE Guarantee, July 29th 1994 and turbines photos.
Auxiliary consumption of the plant	MW	Technology provider	1,32	Three (3) natural gas turbines. Each one consume 439 kW. GE Guarantee, July 29th 1994.
Open Cycle Net Installed Capacity	MW	Calculated	368,61	-
Project				
Steam turbine gross installed capacity	MW	Technology provider	176,90	Engineering Project, Key Reference Terms of Proposal (12 July 2007)
Auxiliary consumption of the plant	MW	Project developer	7,65	Isolux Corsan proposal, Annex I Off-shore Electrical System 2007/5287-E-001 (4 Sept. 2007)
Steam turbine net capacity	MW	Calculated	169,25	-
Gross installed capacity combined cycle	MW	Calculated	546,83	-
Combined cycle Net installed capacity	MW	Calculated	537,86	-
Load Factor	%	Project developer	89,9%	Study of projects at Thermal Power Plants Guemes and Loma La Lata and their operation in the Wholesale Electricity Market (MEM), "Mercado Eléctrico Consultores", May 2007
Reserve for frecuency regulation	%	Project developer / CAMMESA	3%	CAMMESA, Frequency reg. 2007
Effective load factor	%	Calculated	86,9%	-
Operational hours/year	hrs/yr	Project developer	8.760	-

These values were used for calculations according to version 02 of ACM0007 (version available at the time of investment decisions).

<u>Comparative analysis between the benchmark and the project IRR</u>

Scenario	IRR
Project activity without CDM	9.89%
Benchmark	13.31%

The IRR of the Project activity without CDM is lower than the benchmark indicating that the investment in the Project without any incentives from CDM is not viable for a rational investor. The registration of the Project activity under the CDM will result in additional revenues for the Project activity, helping it to alleviate the major institutional and investment barriers, and the minor technological barriers, faced by the project activity.

<u>Sensitivity analysis</u>

A sensitivity analysis was conducted by altering the following parameters up to ± 10% in order to show that the conclusion of the benchmark analysis is robust to reasonable variations in the critical assumptions:

- Investment;

- Price of electricity sold in the Energy Plus market;
- O&M costs;
- Gas price;
- Electricity generated.

These parameters were selected as they are the most likely to fluctuate over time and can significantly affect the financial attractiveness of the Project.

It is important to mention that while the natural gas price is directly related to the price of electricity (under "Energía Plus" contracts), it was varied independently, since it represents about 58% of total costs. An increase of natural gas price would be directly transferred to the electricity tariff affecting the Project profitability in parallel with the electricity price change. The same consideration applies when varying the price of electricity under Energía Plus contracts while maintaining fixed the price of gas.

The sensitivity analysis was performed by altering the parameters ±*10%* and by determining the variation required to achieve feasibility.

The electricity price was capped at AR$ 185/MWh by the Secretariat of Energy through Note N° 567 of June 15, 2007 for customers GUMAS and GUMES. This value represents a +4.77% upside of the Energía Plus prices used in the financial analysis. For this reason a floor of −10% (default) and a ceiling of +5% for the calculation of sensitivity of the variable cost of the Energía Plus sold by the Power Plant Loma de la Lata is deemed appropriate. However, the variations are taken for the range ±10% as a conservative assumption.

The trend in gas prices was rising in the period 2006-2007 and the international price of gas was three times that of Argentina in the same period[62], so that the value adopted for the natural gas price for Plus contracts is a conservative value. The invoice (December 31, 2011) of one of the natural gas suppliers under the Plus contract shows that the value at the date of payment was 5 US$/MMBTU. For this reason a ±10% as the default value for variations in relation to price considerations is considered reasonable. It is moreover reinforced considering that a reduction in natural gas prices is unlikely within a market that is reducing its reserves and is increasing the imports of primary resources. Moreover, a significant increase in the price of gas for the project would be not feasible without a corresponding increase in the price of energy, which was capped at the time.

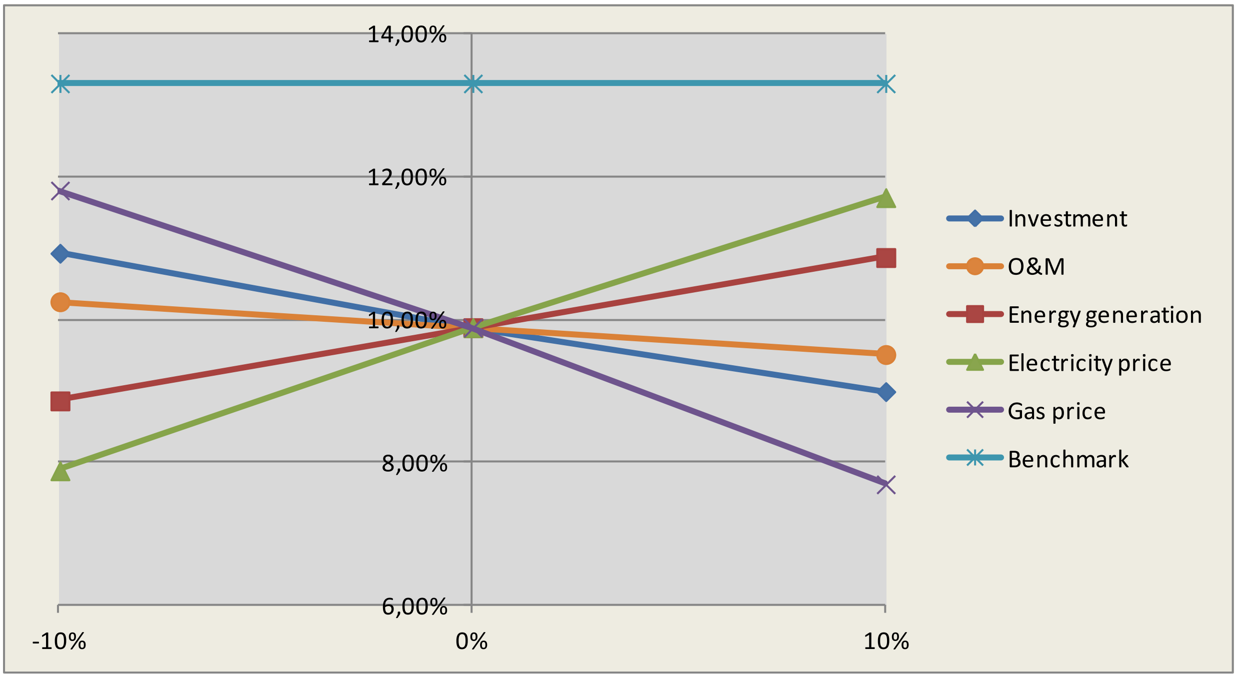
Table A5-4 and figure A5-1 below show the results of the sensitivity analysis:

[62] See spreadsheet "Gas Prices (International, AR Reference, Energía Plus) Aug06-Sept07.xlxs".

Table A5-4: Sensitivity analysis

IRR	-10%	0%	10%
Investment	10.93%	9.89%	8.99%
O&M	10.25%	9.89%	9.51%
Energy generation	8.86%	9.89%	10.87%
Electricity price	7.88%	9.89%	11.71%
Gas price	11.81%	9.89%	7.69%
Benchmark	13.31%	13.31%	13.31%

Figure A5-1: Sensitivity analysis



As a result, the sensitivity analysis shows that the benchmark analysis is robust to reasonable variations in the critical assumptions.

Build Margin Calculation – 2011 data applied[63]

Last five power plants, step (a):

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[63] Data are extracted from calculations for the building margin (BM) by the Project Participant using SADI's information, provided by CAMMESA for the year 2011 (please refer to spreadsheet "2011 Argentine grid building margin.xlsx" for the detailed calculation).

Power Plant	Construction date	Name of Unit	Electricity generation (MWh)	Accumulated generation percentage over total generation
GENCOR	Dec-11	RTERTG01	509	0.00%
GENCOR	Dec-11	RTERTG02	501	0.00%
CT INTA CATAMARCA - ENARSA	Dec-11	INTADI01	-	0.00%
CT BARILOCHE - ENARSA	Dec-11	BARIDI01	1	0.00%
HYCHICO P. EOLICO DIADEMA	Dec-11	DIADEO	6,315	0.01%

Final set of power plants after steps (e) and (f):

Power Plant	Construction date	Name of Unit	Electricity generation (MWh)	Accumulated generation percentage over total generation
GENCOR	Dec-11	RTERTG01	509	0.00%
GENCOR	Dec-11	RTERTG02	501	0.00%
CT INTA CATAMARCA - ENARSA	Dec-11	INTADI01	-	0.00%
CT BARILOCHE - ENARSA	Dec-11	BARIDI01	1	0.00%
HYCHICO P. EOLICO DIADEMA	Dec-11	DIADEO	6,315	0.01%
C.H. SAN GUILLERMO SIEyE	Dec-11	SGUIHI	-	0.01%
PARQUE EOLICO ARAUCO SAPEM	Dec-11	ARAUEO	6,700	0.01%
PTA FOTOVOLTAICA S.JUAN I-EPSE	Dec-11	SJUAFV	1,691	0.01%
GENERACION INDEPENDENCIA S.A.	Nov-11 Dec-11	INDETG01	1,432	0.01%
CT ORAN - ENARSA	Nov-11	ORADDI01	12	0.01%
CT LOBOS BS.AS - ENARSA	Nov-11	LOBODI01	2,645	0.02%
GENERACION INDEPENDENCIA S.A.	Nov-11	INDETG02	1,437	0.02%
C.MEDANITOS-RINCON SAUCES	Oct-11	RSAUDI01	220,824	0.20%
CT AÑATUYA II - ENARSA	Aug-11	ANATDI02	2,608	0.20%
CT VIALE - ENARSA	Aug-11	VIALDI01	105	0.20%
CT ARRECIFES-ENARSA	Jun-11 Aug-11	ARREDI01	7,035	0.21%
CT ESQUINA - ENARSA	Feb-11 May-11 Aug-11	ESQDDI01	4,306	0.21%
CT SALTO - ENARSA	Jan-11 Apr-11 Jul-11	SLTODI01	90,620	0.29%
CT SANTA ROSA - ENARSA	Mar-11 Jul-11	SROSDI01	16,567	0.30%
COOP. VILLA GESELL GENERACIÓN	Jul-11	VGEPDI01	85	0.30%
CT REALICO - ENARSA	Apr-11 Jun-11	REALDI01	11,687	0.31%
CT BRAGADO - ENARSA	Jun-11	BRAGTG01	37,685	0.34%
CT BRAGADO - ENARSA	Jun-11	BRAGTG02	30,153	0.37%

ECOENERGÍA	Jun-11	CERITV01	20,136	0.38%
CENTRAL TERMICA PIQUIRENDA	May-11	PIQIDI01	61,720	0.43%
CT LA RIOJA SUR- ENARSA	May-11	LRISDI01	7,651	0.44%
CT ALEM - ENARSA	May-11	ALEMDI01	7,241	0.45%
CH SAN MARTIN	Apr-11	SMARHI	11,278	0.45%
CH LOS CORONELES	Apr-11	COROHI	12,916	0.47%
CH ALVAREZ CONDARCO	Apr-11	CONDHI	172,091	0.61%
HIDROELECTRICA REYES EJSEDSA	Apr-11	RREYHI	17,140	0.62%
CT LAS ARMAS II - ENARSA	Apr-11	ARMATG03	112,471	0.71%
CT BELL VILLE - ENARSA	Jan-11 Mar-11	BVILDI01	28,784	0.74%
CT COLON BS.AS, - ENARSA	Feb-11	COLBDI01	23,192	0.76%
CT LINCOLN - ENARSA	Jan-11	LINCDI01	40,441	0.79%
CT CORRIENTES - ENARSA	Jan-11	CORRDI01	19,591	0.81%
CT CHILECITO - ENARSA	Jan-11	CHLEDI01	12,931	0.82%
CT GRAL. VILLEGAS - ENARSA	Jan-11	VGADDI01	48,365	0.86%
ENARSA GOYA	Dec-10	GOYDDI01	20,361	0.87%
EOLICA NECOCHEA	Nov-10	NECOEO	309	0.87%
GENERACIÓN MEDITERRÁNEA MODESTO MARANZANA	Sep-10	MMARTG05	217,387	1.05%
ENARSA LAS PALMAS	Sep-10	LPALDI01	5,306	1.06%
ENARSA ARISTOBULO DEL VALLE	Sep-10	ARISDI01	33,935	1.09%
EPEC ARTURO ZANICHELLI	Aug-10	PILATG11	745,139	1.70%
EPEC ARTURO ZANICHELLI	Aug-10	PILATG12	753,974	2.32%
ENARSA ING JUAREZ	Aug-10	JUARDI01	13,998	2.34%
ENERGIA DEL SUR	Jul-10	PATATV01	291,856	2.58%
AUTOGENERADOR AZUCARERA JUAN M. TERÁN S.A.	Jul-10	ISBATV01	8,270	2.58%
ENARSA SAENZ PEÑA II	Jun-10	SPE2DI01	7,622	2.59%
ENARSA VILLA ANGELA	Apr-10	VANGDI01	6,865	2.59%
ENARSA CHARATA	Mar-10	CHARDI02	13,883	2.61%
ENARSA LAGUNA BLANCA	Feb-10	LBLADI01	14,891	2.62%
FIDEICOMISO CT TIMBÚES	Feb-10	TIMBTV01	1,228,313	3.63%
ENARSA CAPITAN SARMIENTO	Jan-10	CSARDI01	19,234	3.65%
FIDEICOMISO CT MANUEL BELGRANO	Jan-10	GBELTV01	1,359,906	4.77%
CHARATA ENARSA	Dec-09	CHARDI01	8,882	4.78%
FORMOSA DELIVER	Oct-09	FORDDI02	13,351	4.79%
LAS ARMAS	Oct-09	ARMATG01	15,848	4.80%
LAS ARMAS	Oct-09	ARMATG02	16,120	4.82%
SOLALBAN	Oct-09	SOLATG01	297,162	5.06%
CONCEP. URUGUAY	Oct-09	CURUTG02	21,123	5.08%
CONCEP. URUGUAY	Sep-09	CURUTG01	20,796	5.10%
OLAVARR DELIVER	Sep-09	OLADTG02	29,319	5.12%
OLAVARR DELIVER	Aug-09	OLADTG01	29,523	5.14%
LIB. SAN MARTIN	Aug-09	LIBEDI01	17,408	5.16%
A.P. PTO PIRAY (*)	Aug-09	PUPITV01	83,182	5.23%
C.T. GENELBA	Jul-09	GEBATG03	332,820	5.50%
CARACOLES	Jul-09	CCOLHI	60,969	5.55%

ALUMINE	Jun-09	ALUMDI01	1,182	5.55%
CAVIAHUE	Jun-09	CAVIDI01	1,351	5.55%
TARTAGAL ENARSA	May-09	TARDDI01	16,878	5.57%
PARANA	May-09	PARATG01	22,159	5.59%
PARANA	May-09	PARATG02	22,792	5.61%
3 ARROY QUILMES	May-09	3ARRDI01	245	5.61%
PASO DE LA PATRIA	May-09	PPATDI01	12,387	5.62%
CIPOLLETI (ENARSA)	Apr-09	CIPODI01	3,030	5.62%
VILLA REGINA	Apr-09	VREGDI01	4,364	5.62%
RAFAELA	Jan-09	RAFADI01	17,635	5.64%
SAN CLEM. TUYU	Jan-09	SCTPDI01	957	5.64%
VENADO TUERTO	Dec-08	VTUEDI01	216	5.64%
MATHEU (ENARSA)	Nov-08	MATHTG02	25,050	5.66%
	Nov-08	MATHTG01	23,984	5.68%
LA PLATA (ENARSA)	Nov-09	LPLADI01	28,548	5.70%
LA BANDA	Oct-08	LBANTG22	2,850	5.70%
MODESTO MARANZANA	Nov-08	MMARTG04	234,703	5.90%
	Nov-08	MMARTG03	245,608	6.10%
SAENZ PEÑA	Oct-08	SPENDI01	11,919	6.11%
GUEMES	Sep-08	GUEMTG01	550,871	6.56%
FORMOSA (ENARSA)	Sep-08	FORDDI01	9,917	6.57%
PIRANÉ (ENARSA)	Aug-08	PIRADI01	5,189	6.58%
AÑATUYA(ENARSA)	Aug-08	ANATDI01	23,979	6.60%
CT TIMBUES (GSMA)	Jun-08	TIMBTG02	1,349,596	7.71%
	Jun-08	TIMBTG01	1,234,918	8.73%
ENTRELOMAS	Jun-08	ELOMDI01	16,829	8.74%
LA RIOJA	Jun-08	LRIDDI01	8,869	8.75%
CATAMARCA DELIV (ENARSA)	Jun-08	CATDDI01	45,090	8.79%
ISLA VERDE (ENARSA)	May-08	ISVEDI01	95,347	8.87%
PEHUAJÓ (ENARSA)	May-08	PEHUDI01	94,428	8.94%
JUNIN (ENARSA)	Apr-08	JUNIDI01	96,560	9.02%
GRAL BELGRANO	Jun-08	GBELTG02	1,372,651	10.16%
	Apr-08	GBELTG01	1,435,054	11.34%
CASTELLI(ENARSA)	Feb-08	CASTDI01	24,554	11.36%
PINAMAR (ENARSA)	Feb-08	PINATG07	29,882	11.39%
PINAMAR (ENARSA)	Feb-08	PINATG08	27,936	11.41%
PINAMAR (ENARSA)	Feb-08	PINATG09	29,786	11.43%
PINAMAR (ENARSA)	Feb-08	PINATG10	28,548	11.46%
AUTOGENERADOR MOLINOS RIO DE LA PLATA	Nov-07	MOLITV01	21,520	11.48%
SAN NICOLAS	Apr-04	SNICTG01	214	11.48%
SHELL DOCK SUD	Nov-03	SHELTG01	14,450	11.49%
PLUS PETROL NORTE	Feb-03	PPNOTG02	-	11.49%
LAS MADERAS	Oct-02	LMADHI	93,443	11.57%
CARRIZAL	Aug-02	CARRHI	47,022	11.60%
CACHEUTA	May-02	CACHHI	348,802	11.89%
CTSM DE TUCUMAN	Feb-02	SMTUTV01	613,516	12.40%
	Feb-96	SMTUTG01	531,230	12.84%
	Feb-02	SMTUTG02	617,887	13.35%
PLUS PETROL NORTE	Jan-02	PPNOTG01	62,548	13.40%

COMODORO RIVADAVIA	Sep-01	CRIVTV25	3,262	13.40%
	Sep-01	CRIVTG28	55,573	13.45%
	Sep-01	CRIVTG27	-	13.45%
AES PARANA	May-01	AESPTV01	1,672,835	14.83%
	May-01	AESPTG02	1,541,503	16.10%
	May-01	AESPTG01	1,543,819	17.37%
CUESTA DEL VIENTO	Nov-01	CVIEHI	17,823	17.39%
DOCK SUD	Jun-00	DSUDTV11	1,868,154	18.93%
	Jun-00	DSUDTG10	1,566,180	20.22%
TOTAL			**24,502,262**	**21.219%**

The applied fossil-fuel CO_2 emission factors are showed below.

Diesel	Fuel oil	Natural Gas
2.683	3.197	1.951
tCO_2/m^3	tCO_2/t	tCO_2/Dam^3

The table below summarizes the CO_2 emissions calculated for each power plant constituting the build margin.

POWER PLANT	NAME OF UNIT	FUEL OIL [Ton]	NATURAL GAS [Dam3]	GAS OIL/DIESEL [m3]	TOTAL EMISSIONS (t CO2)
GENCOR	RTERTG01	-	299	125	917
GENCOR	RTERTG02	-	249	147	880
CT INTA CATAMARCA - ENARSA	INTADI01	-	-	-	-
CT BARILOCHE - ENARSA	BARIDI01	-	-	-	-
HYCHICO P. EOLICO DIADEMA	DIADEO	-	-	-	-
C.H. SAN GUILLERMO SIEyE	SGUIHI	-	-	-	-
PARQUE EOLICO ARAUCO SAPEM	ARAUEO	-	-	-	-
PTA FOTOVOLTAICA S.JUAN I-EPSE	SJUAFV	-	-	-	-
GENERACION INDEPENDENCIA S.A.	INDETG01	-	4	428	1,157
CT ORAN - ENARSA	ORADDI01	-	-	-	-
CT LOBOS BS.AS - ENARSA	LOBODI01	-	-	-	-
GENERACION INDEPENDENCIA S.A.	INDETG02	-	5	423	1,144
C.MEDANITOS-RINCON SAUCES	RSAUDI01	-	67,525	-	131,742
CT AÑATUYA II - ENARSA	ANATDI02	-	-	266	715
CT VIALE - ENARSA	VIALDI01	-	-	-	-
CT ARRECIFES-ENARSA	ARREDI01	-	-	-	-
CT ESQUINA - ENARSA	ESQDDI01	-	-	662	1,777
CT SALTO - ENARSA	SLTODI01	-	-	25,456	68,298

CT SANTA ROSA - ENARSA	SROSDI01	-	-	4,727	12,682
COOP. VILLA GESELL GENERACIÓN	VGEPDI01	-	-	20	55
CT REALICO - ENARSA	REALDI01	-	-	3,071	8,240
CT BRAGADO - ENARSA	BRAGTG01	-	-	-	-
CT BRAGADO - ENARSA	BRAGTG02	-	-	-	-
ECOENERGÍA	CERITV01	-	-	-	-
CENTRAL TERMICA PIQUIRENDA	PIQIDI01	-	17,628	-	34,392
CT LA RIOJA SUR- ENARSA	LRISDI01	-	-	1,769	4,746
CT ALEM - ENARSA	ALEMDI01	-	-	-	-
CH SAN MARTIN	SMARHI	-	-	-	-
CH LOS CORONELES	COROHI	-	-	-	-
CH ALVAREZ CONDARCO	CONDHI	-	-	-	-
HIDROELECTRICA REYES EJSEDSA	RREYHI	-	-	-	-
CT LAS ARMAS II - ENARSA	ARMATG03	-	32,749	6,426	81,136
CT BELL VILLE - ENARSA	BVILDI01	-	-	5,889	15,800
CT COLON BS.AS, - ENARSA	COLBDI01	-	-	7,046	18,904
CT LINCOLN - ENARSA	LINCDI01	-	-	11,798	31,654
CT CORRIENTES - ENARSA	CORRDI01	-	-	6,310	16,929
CT CHILECITO - ENARSA	CHLEDI01	-	-	3,648	9,789
CT GRAL. VILLEGAS - ENARSA	VGADDI01	-	-	13,742	36,871
ENARSA GOYA	GOYDDI01	-	-	5,944	15,947
EOLICA NECOCHEA	NECOEO	-	-	-	-
GENERACIÓN MEDITERRÁNEA MODESTO MARANZANA	MMARTG05	-	56,280	6,188	126,406
ENARSA LAS PALMAS	LPALDI01	-	-	1,486	3,987
ENARSA ARISTOBULO DEL VALLE	ARISDI01	-	-	9,941	26,671
EPEC ARTURO ZANICHELLI	PILATG11	-	222,428	41,541	545,413
EPEC ARTURO ZANICHELLI	PILATG12	-	210,026	33,927	500,787
ENARSA ING JUAREZ	JUARDI01	-	-	4,060	10,892
ENERGIA DEL SUR	PATATV01	-	27,995	-	54,619
AUTOGENERADOR AZUCARERA JUAN M. TERÁN S.A.	ISBATV01	4,936	-	-	15,780
ENARSA SAENZ PEÑA II	SPE2DI01	-	-	2,208	5,924
ENARSA VILLA ANGELA	VANGDI01	-	-	1,981	5,316
ENARSA CHARATA	CHARDI02	-	-	4,124	11,065
ENARSA LAGUNA BLANCA	LBLADI01	-	-	4,636	12,439
FIDEICOMISO CT TIMBÚES	TIMBTV01	-	-	-	-
ENARSA CAPITAN SARMIENTO	CSARDI01	-	-	5,538	14,858
FIDEICOMISO CT MANUEL BELGRANO	GBELTV01	-	-	-	-
CHARATA ENARSA	CHARDI01	-	-	2,617	7,022
FORMOSA DELIVER	FORDDI02	-	-	3,968	10,647
LAS ARMAS	ARMATG01	-	5,450	848	12,910

LAS ARMAS	ARMATG02	-	5,522	879	13,132
SOLALBAN	SOLATG01	-	89,320	-	174,263
CONCEP. URUGUAY	CURUTG02	-	4,198	3,053	16,380
CONCEP. URUGUAY	CURUTG01	-	4,354	2,933	16,363
OLAVARR DELIVER	OLADTG02	-	7,552	2,763	22,148
OLAVARR DELIVER	OLADTG01	-	7,795	2,799	22,717
LIB. SAN MARTIN	LIBEDI01	-	-	5,505	14,770
A.P. PTO PIRAY (*)	PUPITV01	30,349	-	-	97,025
C.T. GENELBA	GEBATG03	-	114,987	-	224,339
CARACOLES	CCOLHI	-	-	-	-
ALUMINE	ALUMDI01	-	-	344	923
CAVIAHUE	CAVIDI01	-	-	347	931
TARTAGAL ENARSA	TARDDI01	-	-	5,166	13,859
PARANA	PARATG01	-	4,775	2,967	17,276
PARANA	PARATG02	-	4,723	3,202	17,805
3 ARROY QUILMES	3ARRDI01	-	67	-	130
PASO DE LA PATRIA	PPATDI01	-	-	3,499	9,388
CIPOLLETI (ENARSA)	CIPODI01	-	-	908	2,436
VILLA REGINA	VREGDI01	-	-	1,260	3,381
RAFAELA	RAFADI01	-	-	5,298	14,214
SAN CLEM. TUYU	SCTPDI01	-	-	236	633
VENADO TUERTO	VTUEDI01	-	-	70	189
MATHEU (ENARSA)	MATHTG02	-	7,078	1,772	18,563
	MATHTG01	-	6,675	1,989	18,357
LA PLATA (ENARSA)	LPLADI01	-	-	7,587	20,357
LA BANDA	LBANTG22	-	623	1,354	4,849
MODESTO MARANZANA	MMARTG04	-	65,228	9,927	153,894
	MMARTG03	-	62,024	14,444	159,763
SAENZ PEÑA	SPENDI01	-	-	3,635	9,753
GUEMES	GUEMTG01	-	133,207	-	259,887
FORMOSA (ENARSA)	FORDDI01	-	-	2,908	7,803
PIRANÉ (ENARSA)	PIRADI01	-	-	1,413	3,791
AÑATUYA(ENARSA)	ANATDI01	-	-	6,374	17,102
CT TIMBUES (GSMA)	TIMBTG02	-	280,401	158,039	971,082
	TIMBTG01	-	235,971	169,149	914,206
ENTRELOMAS	ELOMDI01	-	4,328	-	8,443
LA RIOJA	LRIDDI01	-	-	2,521	6,763
CATAMARCA DELIV (ENARSA)	CATDDI01	-	-	12,432	33,356
ISLA VERDE (ENARSA)	ISVEDI01	-	-	26,370	70,751
PEHUAJÓ (ENARSA)	PEHUDI01	-	-	26,717	71,681
JUNIN (ENARSA)	JUNIDI01	-	-	27,400	73,515
GRAL BELGRANO	GBELTG02	-	328,823	118,472	959,396
	GBELTG01	-	344,734	105,549	955,763
CASTELLI(ENARSA)	CASTDI01	-	-	6,927	18,585
PINAMAR (ENARSA)	PINATG07	-	9,546	2,268	24,707
PINAMAR (ENARSA)	PINATG08	-	9,351	1,654	22,682
PINAMAR (ENARSA)	PINATG09	-	9,782	1,951	24,320
PINAMAR (ENARSA)	PINATG10	-	9,345	2,021	23,654
AUTOGENERADOR MOLINOS RIO DE LA PLATA	MOLITV01	184	2,748	-	5,950

SAN NICOLAS	SNICTG01	-	161	55	462
SHELL DOCK SUD	SHELTG01	-	5,228	-	10,200
PLUS PETROL NORTE	PPNOTG02	-	-	-	-
LAS MADERAS	LMADHI	-	-	-	-
CARRIZAL	CARRHI	-	-	-	-
CACHEUTA	CACHHI	-	-	-	-
CTSM DE TUCUMAN	SMTUTV01	-	-	-	-
	SMTUTG01	-	207,297	-	404,437
	SMTUTG02	-	233,933	-	456,403
PLUS PETROL NORTE	PPNOTG01	-	20,776	-	40,535
COMODORO RIVADAVIA	CRIVTV25	-	-	-	-
	CRIVTG28	-	21,672	-	42,282
	CRIVTG27	-	-	-	-
AES PARANA	AESPTV01	-	-	-	-
	AESPTG02	-	340,696	138,861	1,037,262
	AESPTG01	-	310,537	156,584	1,025,973
CUESTA DEL VIENTO	CVIEHI	-	-	-	-
DOCK SUD	DSUDTV11	-	-	-	-
	DSUDTG10	-	403,542	80,403	1,003,032
TOTAL					**11,420,378**

The build margin CO_2 emission factor for grid connected power generation ($EF_{grid,BM,y}$) is calculated as the total emissions (tCO_2) divided by the total power generation:

$$EF_{Grid,BM,y} = 11{,}420{,}378\ tCO_2e / 24{,}231{,}807\ MWh = 0.466\ \ tCO_2e / MWh$$

For further information on the SADI grid emission factor estimation, please refer to “2011 Argentine grid building margin.xlsx” file.

Annex 4

MONITORING INFORMATION

Please refer to section B.7.2 to all necessary monitoring information.

A specific monitoring plan for the CDM project has been designed. A Spanish version of this monitoring plan is used by all responsible of the different tasks. A copy of this plan is shown to the DOE validating the Project.