



MGM International, Inc.

Graneros Plant Fuel Switching Project

Nestlé S.A., Chile

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Prepared by

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Acknowledgements

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Notation

AFC_j	annual consumption of fuel	m ³ or kg
$E_{equiv\ met\ comb}$	CO ₂ equivalent of methane emissions from fuel combustion	tonne CO ₂ equiv/year
$BE_{met\ comb}$	Methane emissions from fuel combustion	tonne CH ₄ /year
$BE_{equiv\ met\ comb}$	CO ₂ equivalent of methane emissions from fuel combustion	tonne CO ₂ equiv/year
$BE_{N_2O\ comb}$	nitrous oxide emissions from fuel combustion	tonne N ₂ O/year
$BE_{equiv\ N_2O\ comb}$	CO ₂ equivalent of nitrous oxide emissions from fuel combustion	tonne CO ₂ equiv/year
$BE_{equiv\ fug}$	CO ₂ equivalent of fugitive methane emissions from coal mining	tonne CO ₂ equiv/year
BE_{fug}	Fugitive methane emissions from coal mining	tonne CH ₄ /year
BE_{total}	total baseline GHG emissions	tonne CO ₂ equiv/year
$BE_{transport}$	CO ₂ emissions per year from coal transport	tonne CO ₂ /year
CV_j	lower heating value of fuel j	kcal/kg or kcal/m ³
DD	diesel density	kg/litre
E_j	CO ₂ emissions per year from fuel j combustion	tonne CO ₂ /year
$E_{equiv\ fug}$	CO ₂ equivalent of fugitive methane emissions from natural gas production, pipeline and distribution leaks	tonne CO ₂ equiv/year
$E_{equiv\ met\ comb}$	CO ₂ equivalent of methane emissions from fuel combustion	tonne CO ₂ equiv/year
E_{fug}	Fugitive methane emissions from natural gas production, pipeline and distribution leaks	tonne CH ₄ /year
$E_{met\ comb}$	Methane emissions from fuel combustion	tonne CH ₄ /year
E_{total}	total project GHG emissions	tonne CO ₂ equiv/year
EF_j	CO ₂ emission factor of fuel j	kg CO ₂ /GJ, lower heating value basis
$E_{N_2O\ comb}$	nitrous oxide emissions from fuel combustion	tonne N ₂ O/year
$E_{equiv\ N_2O\ comb}$	CO ₂ equivalent of nitrous oxide emissions from fuel combustion	tonne CO ₂ equiv/year
ER	Emissions reductions from project activities	tonne CO ₂ -equiv/year
FCGR	fuel consumption growth rate	% per year
$GWP(CH_4)$	global warming potential of methane	= 21 for Kyoto Protocol
$GWP(N_2O)$	global warming potential of nitrous oxide	= 310 for Kyoto Protocol
HO_j	heat output of industrial equipment using fuel j	GJ/year
MEF_j	Methane emission factor for fuel j combustion	kg CH ₄ /TJ, lower heating value basis
$MCEF$	Emission factor of methane from coal mining	kg CH ₄ /tonne of coal
MFC_j	Monthly consumption of fuel	m ³ or kg
MLR	Methane leakage rate	kg CH ₄ /GJ of natural gas consumption, LHV basis
NEF_j	nitrous oxide emission factor for fuel j combustion	kg N ₂ O/TJ, lower heating value basis
TFSC	Truck freight specific energy consumption	litre/tonne of coal
η	Energy efficiency of each fuel using equipment	%

A. General description of project activity

A.1 Title of the project activity:

Graneros Plant Fuel Switching Project.

A.2 Description of the project activity:

Graneros is one of the plants of Nestlé Chile S.A. It was established in 1936. The Nestlé Graneros plant produces: baby food (cereals); soluble coffee (Nescafé) and substitutes; malt extract; dried mixes based on sugar (dessert) and other ingredients (baking powder); drink preparations (powdered mixes based on cacao, sugar and other ingredients); and breakfast cereals.

The project activity primarily aims at reducing GHG emissions through fuel switching. The project consists of investment to replace the use of the coal and other fossil fuels by natural gas, funded through the sale of carbon credits in the context of the Clean Development Mechanism (CDM) of the Kyoto Protocol. Currently, coal (and, to a lesser extent, other fossil fuels) is used to generate steam and process heat, with a consumption of 11,400 t/year. The extra income derived from the sale of carbon credits will allow Nestlé to pay for part of the conversion, keeping in mind the low prices of the coal in comparison with natural gas.

The project has the capacity to produce 284,400 **tonnes of CO₂ equivalent emissions reduction** over a 21-year time frame.

The project also brings social (employment, health, and labor conditions), environmental (air quality) and economic benefits, thus contributing to sustainable development objectives of the Chilean Government (in accordance with the Environmental Policy for Region VI developed by CONAMA (Comisión Nacional del Ambiente – National Environmental Commission), <http://www.conama.cl/portal/1255/article-26197.html>). The project has the written approval of CONAMA for voluntary participation, confirming that the project supports sustainable development (see Annex 6).

A.3 Project participants:

1. Project Developer: Nestlé Chile S.A.
 2. Annex I country participant: Electric Power Development Co., Ltd.
- See Contact Information in Annex 1.
PDD Consultant: MGM International, Ltda.

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A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

- A.4.1.1 Host country Party(ies): Chile
- A.4.1.2 Region/State/Province etc.: Región VI
- A.4.1.3 City/Town/Community etc: Graneros
- A.4.1.4 Detail on physical location

The project is located at Nestle’s industrial complex, the Graneros Plant, located in Graneros, 80 km South of Santiago in Chile’s Region VI, Libertador General Bernardo O’Higgins. Libertador Bernardo O’Higgins region is located in the central macro zone of the country. The area is 16,365 km², that represents 2.2% of the national continental territory. Its limits: Santiago Metropolitan region in the North, Maule region in the South, Pacific Ocean in the West and the Andes mountains in the East.

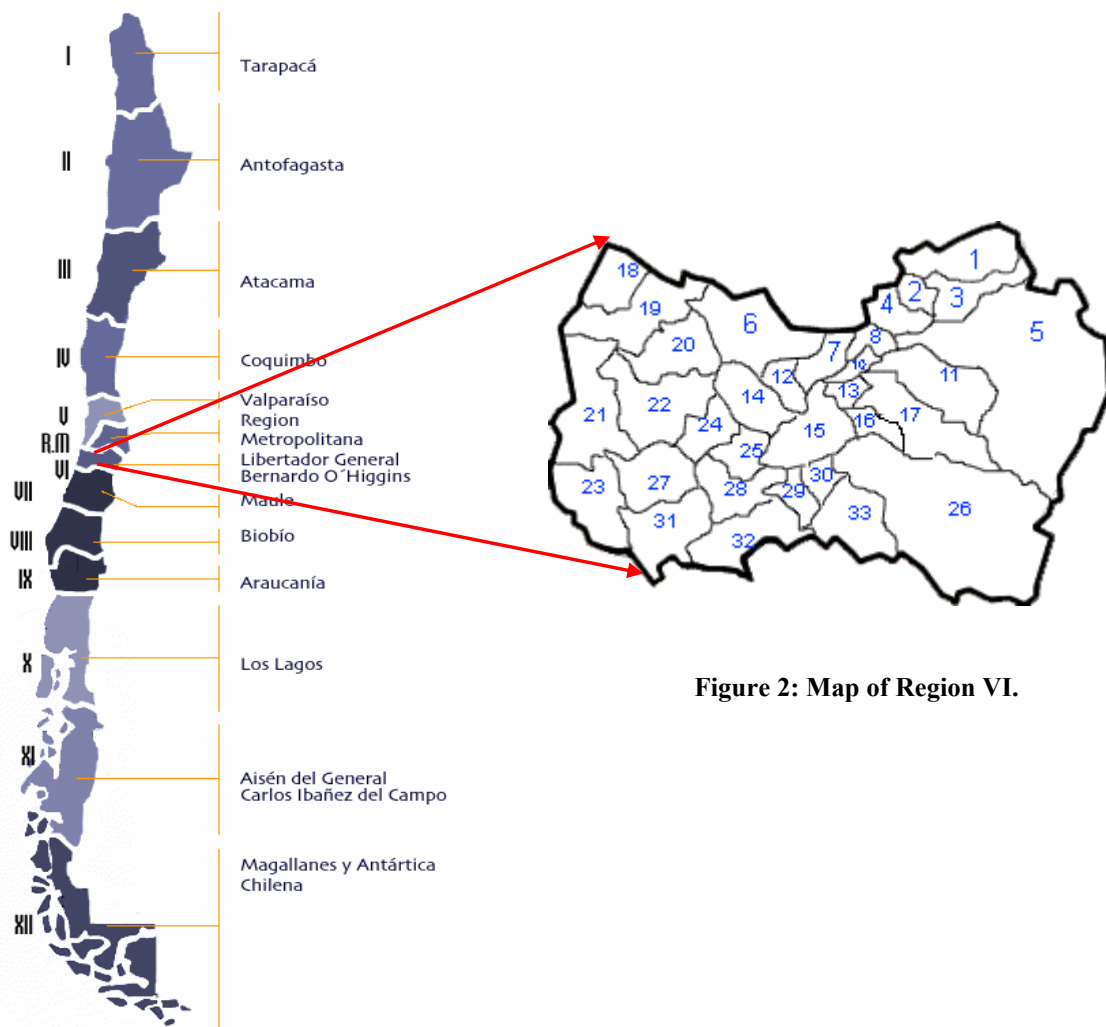


Figure 2: Map of Region VI.

Figure 1: Map of Chile showing the Regions.



Region VI includes 3 provinces: Cachapoal, Colchagua y Cardenal Caro, divided administratively into 33 *comunas* (Figure 2). Graneros is located in Cachapoa province, and shown as #2 in Figure 2.

Between the Census of 1992 and 2002, the region increased its rural population by 23.7%. The Region VI population was 773,950 and that of Graneros 25,883 (Census 2002).

The region has a Regional Environment Policy for Sustainable Development prepared by CONAMA in January 1998 (www.conama.cl), and this project meets all requirements set forth in it.

A.4.2. Category(ies) of project activity

Switching fossil fuels.

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

The project is based on two elements:

- Fuel switching: coal to natural gas
- Fuel switching: petroleum fuels to natural gas

The project plans to convert:

- 2 (NEI) coal boilers with a capacity of 7.5 tonne/h steam (specifications shown in table below)
- 2 (NAS) coal-fired hot-air furnaces with a capacity of 1 million kcal/h (specifications shown in table below).
- 1 Erie City boiler (specifications shown in table below).
- Lilla coffee roaster using diesel (specifications shown in table below).
- 2 (PROBAT) coffee roasters using diesel (specifications shown in table below).
- other small equipment like pots, household kitchen equipment, and bunsen burners that use liquefied petroleum gas. These account for very small amount of energy use, so they are not described in detail.

Figure 3 shows a layout of the factory and indicates the location of the boilers and furnaces to convert to natural gas.

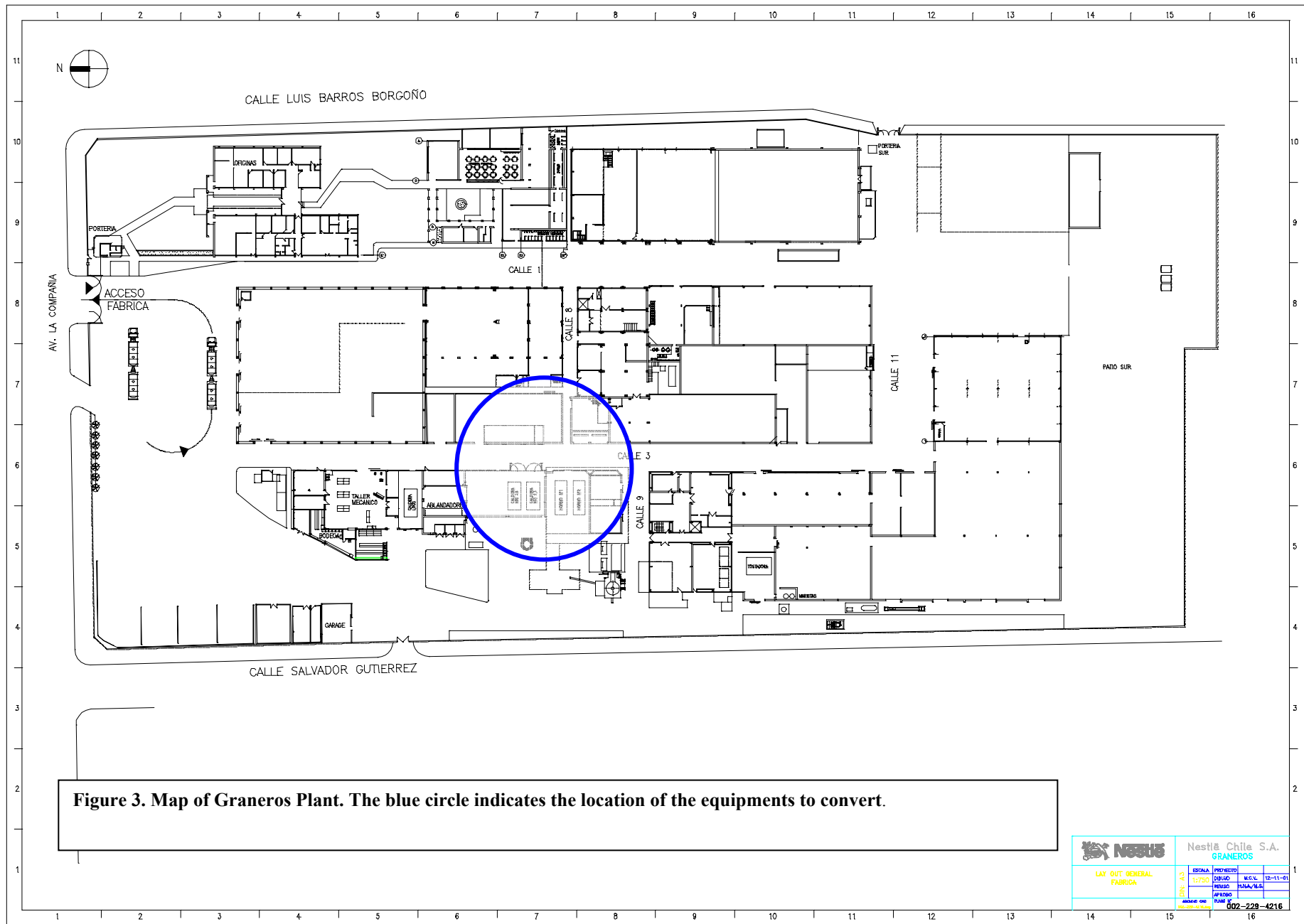


Figure 3. Map of Graneros Plant. The blue circle indicates the location of the equipments to convert.

	Nestlé Chile S.A.		
	GRANEROS		
LAY OUT GENERAL FABRICA	ESCALA 1:750	PROYECTO DIBUJO REVISADO APROBADO PLANO	M.C./E. 12-11-01 EVALUADO EVALUADO EVALUADO EVALUADO
002-229-4216			

Technical characteristics of the 2 NEI boilers	
Manufacturer	NEI Cochran
Serial No.	7431/60 & 7432/60
Year of manufacture	1985
Fuel used	Coal
Type	Fire tube
Maximum operating pressure	14 kg/cm ²
Steam production rate	7,560 kg/h
Fuel consumption rate	715.2 kg/h
Heating surface	273 m ²
Firebox diameter	1.73 m
Firebox length	4.52 m

Technical characteristics of the NAS furnaces	
Year of manufacture	1986
Nominal (rated) capacity	1,000,000 kcal/h
Fuel used	Coal
Heat exchange surface	220 m ²
Hearth length	2.47 m
Hearth width	1.44 m
Hearth height	2.11 m
Burner surface	(1.22 x 2.30 m) = 2.8 m ²
Hearth volume	7.5 m ³
Combustion air intake fan power	5.5 kW
Firebox temperature	715 °C
Stack draft	-18 mbarg

Technical characteristics of the Erie City boiler	
Year of manufacture	1958
Fuel used	Coal
Nominal (rated) capacity	12 t/h
Heat exchange surface	440 m ²
Type	Water tube
Maximum operating pressure	12 bar
Steam production rate	12 kg steam for 1 kg of coal

Technical characteristics of the Lilla coffee roaster	
Model	Opus 40 - Automatic
Nominal (rated) capacity	129 liter/h
Fuel used	Diesel
Furnace	isolated with refractory bricks with 62% alumina
Total engine power	74.5 HP (9 engines)
Control	220 V, 50 Hz
Power	380 V, 50 Hz
Water consumption	8 liter per 60 kg raw coffee
Compressed air consumption	115 Nm ³ /h

Technical characteristics of the PROBAT coffee roaster # 1	
Manufacturer	PROBAT Werke Von Gomborn & Co. K.G. Emmerich Rhein
Serial No.	GO 240/55-4030
Year of manufacture	1955
Fuel used	Diesel
2 Fuel burners	Prior
Nominal (rated) capacity	240 kg green coffee / 20-25 minutes

Technical characteristics of the PROBAT coffee roaster # 2	
Manufacturer	PROBAT Werke Von Gomborn & Co. K.G. Emmerich Rhein
Serial N°	GO 240-62/61/4355-1
Year of manufacture	1962
Fuel used	Diesel
2 Fuel burners	Prior
Nominal (rated) capacity	240 kg green coffee / 20-25 minutes

As part of the project, the 2 PROBAT coffee roasters will be dismantled and replaced by another Lilla coffee roaster (new equipment) with the specifications presented above. Moreover, the Erie City boiler will be dismantled and replaced by a LOSS boiler (see specifications below)

Technical characteristics of the LOSS boiler	
Manufacturer	LOSS INTERNATIONAL
Serial N°	56748
Year of manufacture ¹	1994
Fuel used	Natural gas
Type	Fire tube
Maximum operating pressure	16 bar
Steam production rate	10,000 kg/h
Fuel consumption rate	670 m ³ /h

The two boilers (NEI), two furnaces (NAS) and Lilla coffee roaster are the main equipment to be converted from coal and diesel to natural gas. The burners of NEI, NAS and Lilla Roaster will be replaced by ELCO-KLÖCKNER dual-fuel blower burners, that can burn either natural gas or extra-light fuel oil. Design and performance of the burners comply with the standards DIN 4787, EN pr. 676, DIN 4756, TRG I, DIN EN 298, DIN 4755 and EN 60335-1. Each equipment will include a Roots natural gas meter. For more information see Annex 7.

Miscellaneous small equipment (pots, household kitchen equipment, and bunsen burners) operating on *liquefied petroleum gas* would also be converted to natural gas as part of the pro-

¹ Note that while the boiler is being removed from another Nestlé plant, it is not being replaced by another boiler. This is likely to increase natural gas consumption in other equipment equivalent to the previous consumption by the LOSS boiler. Thus there is no “leakage” in the sense that emissions are increased at that plant because this boiler was shifted to the Graneros plant.

ject. The current consumption of LPG is very small compared to that of coal or diesel. Thus a detailed description of this equipment is not being provided.

The following composition of natural gas is expected²:

	% vol average	% vol minimum	% vol maximum
Methane	97.1	96.7	97.4
Ethane	0.9	1.2	0.8
Propane	0.1	0.2	0.1
Butane	0.0	0.1	0.0
Pentane	0.0	0.0	0.0
Hexane	0.0	0.0	0.0
Nitrogen	0.9	0.9	0.9
Carbon dioxide	0.9	1.0	0.9
Total	100	100	100

The approved methodology applied for this PDD, AM0008, requires that the crediting period shall be capped by the remaining lifetime of the existing equipment(s). Below we provide the reasoning for the fuel switching boiler lifetime to be capped at 50 years.

Before going on, it should be noted that a boiler is not a piece of unitary equipment that is discarded when a defect appears. Operating a boiler requires periodic inspection and maintenance. This is why all industries have permanent boiler maintenance staff. As such, there is not a universally accepted criterion to establish the lifetime of a boiler.

Nestlé has an excellent record of maintenance at its Graneros plant, which means that equipment have long lifetime. In the case of the Graneros plant, the past maintenance records allow us to show that the Erie City boiler, manufactured in 1958, could have been used for 50 years. The results of inspection and maintenance history of the Erie City boiler are given below.

Inspection year/month	Inspection and test results	Maintenance history
December 1992	Internal and external inspection: Satisfactory Hydraulic test: Satisfactory Steam test: Satisfactory Full load test: Satisfactory	No replacement involved
May 1995	Internal and external inspection: Satisfactory Hydraulic test: Satisfactory Steam test: Satisfactory Full load test: Satisfactory	Boiler tube replacement (23 out of 660 at the firebox section)

² Source: Metrogas S.A., August 2003.

July 1998	Internal and external inspection: Satisfactory Hydraulic test: Satisfactory Steam test: Satisfactory Full load test: Satisfactory	Refractory of furnace partially reconditioned
May 1999	Internal and external inspection: Satisfactory Hydraulic test: Satisfactory Steam test: Satisfactory Full load test: Satisfactory	One boiler tube replaced
June 2000	Internal and external inspection: Satisfactory Hydraulic test: Satisfactory Steam test: Satisfactory Full load test: Satisfactory	Thickness measurement of boiler tube. 2 boiler tubes replaced. Refractory replacement.
March 2002	Internal and external inspection: Satisfactory Hydraulic test: Satisfactory Steam test: Satisfactory Full load test: Satisfactory	27 boiler tubes replaced

The above table shows that:

- (i) Most of the maintenance for the past 10 years has been minor.
- (ii) As for the boilers in place, visual inspection with the required tests as shown in the table were conducted. And with this regard, the boiler will be in good shape practically and hence, it will be in use for the next coming 10 years.
- (iii) The thickness measurement test and refractory replacement took place in the year 2000 and, from this point as well, we expect the boiler to require only minor maintenance for the next 10 years.

Therefore, past maintenance records strongly suggest that the Erie City boiler would be in operating condition up till the end of year 2008 and hence, putting 50 years cap as a lifetime will give a conservative number.

The other boilers at the plant were manufactured and installed much more recently, while being subject to the same level of rigour in maintenance, so that we can expect these boilers to be in good shape and until the end of the entire crediting period (21 years).

The PROBAT coffee roasters are small equipment not subject to periodic regulatory inspections, which apply to boilers. The configuration of this equipment is simpler than that of a boiler, requiring little maintenance. In fact, only minor maintenance has been made in the last decade, such as bearings, general check-up, and paint. Thus, we would expect it to last longer than the entire crediting period. But in order to be conservative, we also put the life time of the PROBAT coffee roasters as 50 years.

Thus, we estimate 50 years as a lifetime of the boilers in place for this project. The following table summarises data on the lifetime for each boiler and coffee roaster.



Year of manufacture and lifetime of the boiler and roaster

Name type of the boilers	Year of manufacture	End of lifetime
NEI boiler	1985	2035
NAS furnace	1986	2036
Erie city boiler	1958	2008
PROBAT coffee roaster #1	1955	2005
PROBAT coffee roaster #2	1962	2012

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

The proposed CDM project would reduce the emissions of CO₂ by replacing more carbon intensive fuels (coal and petroleum fuels) by natural gas. Reduced coal consumption at the project site would reduce fugitive methane emissions associated with coal mining and post-mining activities. There would be additional reduction in emissions from coal transport that would no longer be needed.

On the other hand, increased natural gas use at the project site would increase fugitive methane emissions in the natural gas pipeline supplying the project site, and leaks at the site.

Thus the project affects both CO₂ and CH₄ emissions. Overall, the project has the capacity to reduce CO₂ –equivalent GHG emissions by 284,400 tonnes over a 21-year period.

Coal is less expensive than natural gas in the region. Moreover, converting from coal to natural gas would require investment in new equipment. The additional investments and higher operating costs using natural gas implies that the project would not be cost effective on its own, in the absence of credits from GHG emissions reductions. The baseline adopted for the project is based on the assumption that in the absence of carbon finance the company would continue operating its plant with coal, following the trends in the sector as a whole. Thus the proposed project activity is not the baseline and the estimated emission reductions would not occur in the absence of it. Therefore the project shows reduced GHG emissions since the CO₂ emissions from natural gas are lower than from coal, diesel and LPG. The economic assessment in terms of justifying its additionality is described in Sections B.1 and B.4.

A.4.5. Public funding of the project activity:

Nestlé will not receive any national or international public funding whatsoever for the development of this project.

B. Baseline methodology

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

According to the Marrakesh Accords (Decision 17/CP.7), *Modalities and procedures for a clean development mechanism, as defined in Article 12 of the Kyoto Protocol*, paragraph 48 states:

“48. In choosing a baseline methodology for a project activity, project participants shall select from among the following approaches the one deemed most appropriate for the project activity, taking into account any guidance by the executive board, and justify the appropriateness of their choice:

- (a) Existing actual or historical emissions, as applicable; or*
- (b) Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment; or*
- (c) The average emissions of similar project activities undertaken in the previous five years, in similar social, economic, environmental and technological circumstances, and whose performance is among the top 20 per cent of their category.”*

As the proposed baseline methodology has been approved under the name of *“Industrial fuel switching from coal and petroleum to natural gas without extension of capacity and lifetime of the facility”* with the approved number of *“AM0008”* under UNFCCC-CDM dated 15th of June 2004. We will apply this in constructing the baseline scenario demonstrating project additionality and estimating emission reductions.

The baseline methodology adopted for the Graneros Fuel Switching Project fits within option (a) mentioned above: *“existing actual or historical emissions”*, based on actual fuel consumption using the least cost option, from the users’ perspective. (This approach is consistent with option (b) above: *“emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment”*, since a main driver of the baseline —use of coal as opposed to natural gas— is the better economics of coal as opposed to natural gas.)

Coal is less expensive than natural gas in Chile’s Region VI. At the time of initial evaluation, the price of coal was US\$ 2.55 per million Btu (HHV, higher heating value)³ compared to US\$ 3.50 per million Btu (HHV) for natural gas. Moreover, the continued use of coal does not require investments to convert burners and associated equipment from coal and other fuels to natural gas. The baseline methodology includes a test to quantify economic barriers to project implementation, and establish project additionality.

³ Source: GENER, August 2003

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

For the type of components of this particular project (fuel switching from coal and petroleum fuels to natural gas), option (a) above is the most appropriate to use. Reference values for baseline emissions are estimated considering an annual growth rate of 4.12% in fuel use, the average growth rate of coal consumption at the Graneros plant for the 1999-2002 period.

However, the actual baseline proposed is dynamic, taking into account actual changes in fuel consumption over time, following project implementation. The natural gas consumption following project implementation would be replacing a certain amount of coal (and other fuels to a lesser extent), in the absence of the project. Thus, baseline emissions are not fixed to a predetermined time-dependent value but are updated annually through the monitoring process. Baseline emissions change from year to year along with project emissions. The baseline and project energy consumption values are related to each other by the fuel efficiency of each equipment using the fuel prior to fuel switching and with natural gas. The heat output of each equipment is considered unchanged. Such a dynamic baseline is both realistic and easy to determine using the same monitoring and verification protocol used to determine project emissions.

A dynamic baseline is likely to increase the environmental integrity of the project. The time-varying nature of the dynamic baseline is more suited to the project situation, since fuel consumption depends on plant output, which depends on market and other conditions. Plant output does not depend on the fuel Graneros plant is using in the production process (mostly coal under the baseline or natural gas under the CDM project activity).

B.3. Description of how the methodology is applied in the context of the project activity

The methodology is simple to apply. In order to reduce the effect of year-to-year random variations, we consider the base year fuel consumption to be the arithmetic mean of the consumption for the years 2000, 2001 and 2002. Since the fuel consumption increases during this period, considering this 3-year average value is a conservative assumption, since it reduces energy consumption and thus emissions and emissions reduction.

For each fuel, we then calculate total CO₂-equivalent emissions corresponding to this average “base” year. The sum of the emissions from each fuel is the total CO₂ emissions in the baseline for the base year, considered to be 2003. For subsequent years —2004-2010— we consider a 4.12% growth rate of the CO₂ emissions to estimate a “reference” baseline. The baseline emissions used for emissions reductions estimates will depend on actual fuel consumption and will be calculated during the monitoring process (dynamic baseline).



The GHG emissions are made up of carbon dioxide emissions from combustion, methane and nitrous oxide emissions from combustion, and fugitive methane emissions associated with coal mining and from natural gas production, transport and distribution.

Carbon dioxide emissions are determined from the emissions factor for each fuel, with country-specific values for the principal fuels (coal and natural gas) and standard IPCC emissions factors for the standardized petroleum fuels (diesel and LPG), which are used in small quantities in the baseline case.

Methane and nitrous oxide produced in combustion are estimated using IPCC standard emissions factors for each fuel and equipment type.

The fugitive methane emissions associated with coal use are determined by the same coal consumption estimates for each year (2004-2010) and an estimate for the emissions factor for fugitive emissions. Fugitive methane emissions from natural gas production, transport and distribution are also obtained from region-specific emissions factors given by IPCC.

Total methane emissions (from combustion and fugitive emissions) are converted to equivalent CO₂ emissions using the GWP of 21, as agreed on for the First Commitment Period of the Kyoto Protocol.⁴

Similarly, nitrous oxide emissions are converted to equivalent CO₂ emissions using the GWP of 310, as agreed on for the First Commitment Period of the Kyoto Protocol.

The sum of the CO₂ emissions and the CO₂-equivalent methane and nitrous oxide emissions defines the baseline emissions for the first 7-year crediting period. The baseline will be reviewed for the second 7-year crediting period of the project.

⁴ Article 5.3 of the Kyoto Protocol establishes: "The global warming potentials used to calculate the carbon dioxide equivalence of anthropogenic emissions by sources and removals by sinks of greenhouse gases listed in Annex A shall be those accepted by the Intergovernmental Panel on Climate Change and agreed upon by the Conference of the Parties at its third session. Based on the work of, *inter alia*, the Intergovernmental Panel on Climate Change and advice provided by the Subsidiary Body for Scientific and Technological Advice, the Conference of the Parties serving as the meeting of the Parties to this Protocol shall regularly review and, as appropriate, revise the global warming potential of each such greenhouse gas, taking fully into account any relevant decisions by the Conference of the Parties. Any revision to a global warming potential shall apply only to commitments under Article 3 in respect of any commitment period adopted subsequent to that revision."

B.4. 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 (i.e. explanation of how and why this project is additional and therefore not the baseline scenario)

Coal has been less expensive than natural gas in the Region, as we have mentioned in Section B.1. Moreover, converting from coal to natural gas would require investment in new equipment. The additional investments and higher operating costs using natural gas implies that the project would not be cost effective. Credits from GHG emissions reductions reduces the deficit, but at current prices of CERs the project remains marginal. The baseline adopted for the project is based on the assumption that in the absence of carbon finance the company would continue operating its plant principally with coal, since this is the least cost scenario from the company's perspective.

An economic and financial analysis of the fuel switching project is presented below. These calculations are incorporated into the spreadsheet "NGP_Additionality.xls". In these revised calculations, emissions reductions estimates have been reduced for future years as some equipment reach the end of their 50-year life.

At the time the economic analysis was first conducted, prices of coal⁵, diesel⁶, LPG⁷, and natural gas⁸ were: 2.55, 7.42, 11.45, and 3.50 US\$/ million Btu (HHV basis). Moreover, with coal use, there are additional operating costs of 0.06 US\$/million Btu (HHV basis). (Note: 1 Btu = 1055 J.)

As can be seen in the "NGP_Additionality" spreadsheets, for the consumption rates of coal, diesel, and liquefied petroleum gas (LPG) prior to fuel switching, together with prevailing prices, the annual fuel bill would amount to US\$ 985,056. After switching to natural gas, the annual fuel bill would be US\$ 1,195,794. Thus there is an increase in annual fuel cost of US\$ 210,738 per year. Note that the economic analysis conducted in order to demonstrate project additionality did not consider very minor differences in equipment efficiency before and after fuel switching. The error involved is very small and does not affect the overall conclusions regarding additionality.

The additional investment for installing gas lines within the plant and converting the equipment would add up to US\$ 550,270. Investments for connecting the plant to the gas supply pipeline, installing meters and regulators, etc. are not included in this figure.

⁵ Source: GENER (Energy Company), August 2003

⁶ Source: COPEC (Chilean Oil Company), August 2003

⁷ Source: GASCO (LPG Distribution Company), August 2003

⁸ Source: Metrogas (Natural Gas Distribution Company), August 2003



Considering the investments and the difference in fuel prices, and a discount rate of 10%⁹ a year¹⁰, project NPV is US\$ -2,729,990 without carbon credits (assuming that fuel consumption increases at a rate of 4.12% a year as mentioned previously), and US\$ -2,423,570 with carbon credits at US\$ 3/t CO₂ equivalent. *Note that both NPVs are negative.* However, the deficit is substantially reduced through carbon credits. Indeed the value of the credits is approximately the same as the investment requirements for fuel switching, thus helping to offset an investment barrier to project implementation.

The above values correspond to the base case assumptions, using the prevailing coal price of \$2.55 per million Btu and a natural gas price of \$3.50 per MBtu. The “Financial” page of the “NGP Additionality” spreadsheet includes the results of sensitivity analysis with respect to coal and natural gas prices. Since increased price of natural gas alone would only strengthen the case for additionality, we have omitted this option. The results are reproduced below

	Fuel prices, \$ per million Btu		Net present value of investments, 1000 \$	
	Coal	Natural gas	w/o CER revenue	with CER revenue
Base case	2.55	3.50	-2730	-2424
Coal and natural gas both 20% more expensive	3.06	4.20	-3.520	-3.213
Coal 20% more expensive, natural gas price same as base case	3.06	3.50	-1.002	-696
Coal 30% more expensive, natural gas price same as base case	3.31	3.50	-155	152

Nestlé did not use future price projections when they conducted their initial evaluation of project economics. The Chilean government provides statistics of recent fuel and electricity prices http://www.cne.cl/estadisticas/f_estadisticas.html, but not price projections.

While there are likely to be international estimates of coal price futures, these are provided by private energy market research companies to their paid subscribers, and not consulted by the project developers.

Nevertheless we may obtain some information from public data sources. An IEA report¹¹, shows that Australia is one of the principal suppliers of coal worldwide. The table below was extracted from this report. Note that, prior to project implementation, Nestlé purchased Australian coal.

⁹ Source: <http://www.latin-focus.com/latinfocus/countries/chile/chlinter.htm> Benchmark interest rate of Chile, PDBC (Pagarés Descontables del Banco Central) ranged around 3% to 18% from year 1995 to year 2004. We took the mean and consider 10% to be the discount rate.

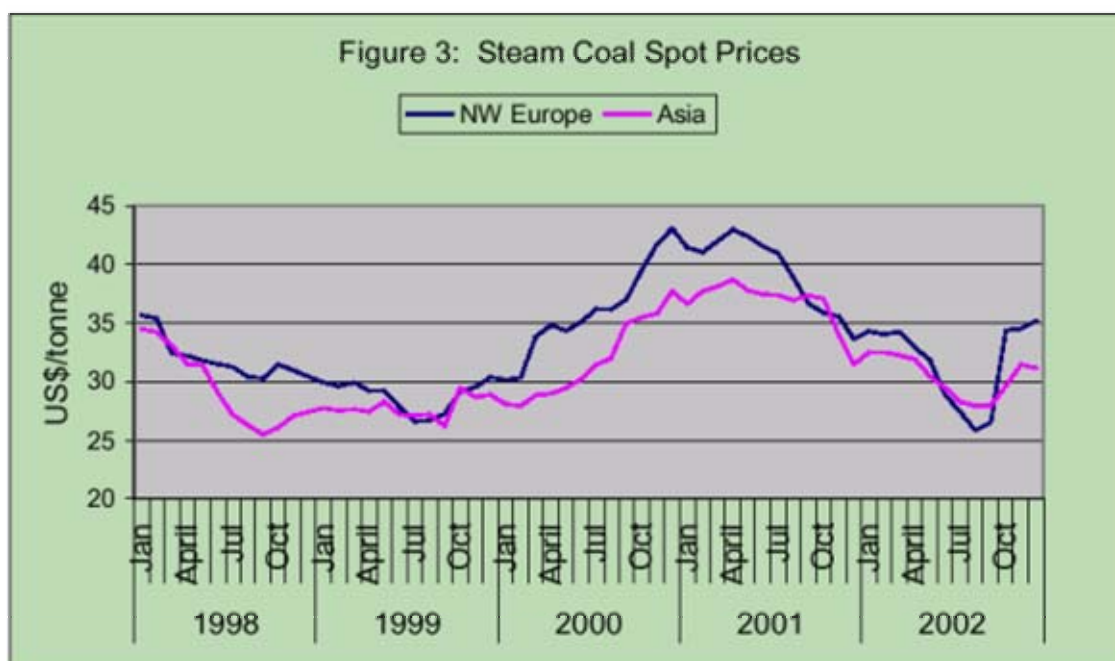
¹⁰ Source: [http://www.indexmundi.com/chile/inflation_rate_\(consumer_prices\).html](http://www.indexmundi.com/chile/inflation_rate_(consumer_prices).html)

¹¹ “Developments in the International Coal Market in 2001-2” by the Coal Industry Advisory Board.

Table 7: World Seaborne Coal Trade - 2002 compared with 2001 (part years only)

Million tonnes		2001			2002			Difference	
Exporting countries	Period	Coking	Steam*	Total	Coking	Steam*	Total	Total	% of 2000
Australia	Jan-Dec	106.2	87.7	193.9	105.3	98.5	203.8	9.9	5
China	Jan-Nov	9.1	69.7	78.8	11.9	65.8	77.7	-1.1	-1
South Africa	Jan-Dec	1.4	67.9	69.3	1.8	67.4	69.2	-0.1	0
Indonesia	Jan-Oct		54.5	54.5		60.5	60.5	6.0	11
Colombia	Jan-Oct		30.7	30.7		27.7	27.7	-3.0	-10
USA+	Jan-Oct	16.9	7.6	24.5	12.6	4.7	17.3	-7.2	-29
Canada	Jan-Sep	19.7	1.7	21.4	15.0	2.7	17.7	-3.7	-17
Russia	Jan-July	4.7	16.0	20.7	5.5	19.2	24.7	4.0	19
Poland (Weglokoks)	Jan-Sep	1.5	10.1	11.6	2.1	9.9	12.0	0.4	-3
Venezuela	Jan-Dec		8.1	8.1		7.8	7.8	-0.3	-4
Vietnam	Jan-Dec		4.2	4.2		5.5	5.5	1.3	31
New Zealand	Jan-June	0.8	0.1	0.9	0.9	0.1	1.0	0.1	11
United Kingdom	Jan-Sep		0.4	0.4		0.4	0.4	0	0
Total		160.3	358.7	519.0	155.1	370.2	525.3	6.3	1
Difference (2002/2001)	Mt				-5.3	11.5	6.3		
As % of 2001					-3	3	1		

The same IEA report gives the following indication of coal price fluctuations from 1998 to 2002 (see figure below). One can observe that steam coal prices fluctuated in the range of US\$ 25 to 42 per tonne, remaining within the range of US\$ 28 to 40 per tonne, over 90% of the time. Thus the 90% range could be stated as US\$ 34 ± 6 per tonne.



Coal has a higher heating value of 28 million Btu/tonne. Thus the “approx. 90% range” of price varies from about US\$ 1 to about \$ 1.43 per million Btu. Note that Nestlé paid approximately US\$ 2.55 per million Btu.

Notably, the figure above shows no indications of a long term trend in coal price, specifically there is no increasing trend in price.

Another source (see Table below) shows that Australian production is expected to increase from 2003-2010, greatly exceeding domestic demand. Thus no coal shortages may be expected in the foreseeable future so that no significant price rise would be expected either.

Natural gas is not a global commodity, since most natural gas is transferred by pipeline so that consumers do not have the option to purchase natural gas from alternative sources. Chile has little natural gas resources and thus imports natural gas from Argentina and Bolivia. Political turmoil in both supplier countries has meant that Chile cannot assure itself of obtaining natural gas in order to meet its demand. In recent months, Chile has decided to import liquefied natural gas from Algeria. Clearly this would mean that natural gas would be much more expensive than by pipeline from neighbouring countries. However, all these events took place after Nestlé’s decision to replace coal with natural gas. In any case, Nestlé could have had access to no information (since such information did not exist) to induce it to think that future natural gas prices would drop below those of coal, so that their fuel switching investment would become cost effective. Indeed, events have turned out in a way for the inverse to be true, i.e. natural gas is turning out to be more expensive, so that the project is even more additional in retrospect.



Thermal coal outlook

	Unit	2003	2004	2005 f	2006 z	2007 z	2008 z	2009 z
World								
Total trade								
Thermal	Mt	519.8	534.1	544.3	554.6	564.1	578.7	589.0
Thermal coal imports								
Asia	Mt	255.0	268.0	275.8	284.8	294.1	308.8	319.2
Chinese Taipei	Mt	47.0	50.0	51.6	52.6	53.8	54.8	56.1
Japan	Mt	102.2	107.1	107.1	108.1	109.2	112.2	114.6
Korea	Mt	54.6	57.5	58.1	60.8	64.9	72.6	76.2
Malaysia	Mt	5.3	6.1	10.4	13.2	14.9	16.7	18.5
Other Asia	Mt	45.9	47.3	48.6	50.1	51.3	52.5	53.8
Europe	Mt	195.2	196.0	197.8	197.6	197.2	196.5	195.8
European Union	Mt	159.9	160.4	161.6	160.7	159.8	158.8	157.6
Other Europe	Mt	35.3	35.6	36.2	36.9	37.4	37.7	38.2
Other	Mt	69.7	70.2	70.8	72.2	72.8	73.4	73.9
Thermal coal exports								
Australia	Mt	103.1	107.9	110.9	122.0	127.4	129.5	131.4
China	Mt	80.7	79.2	77.6	77.5	77.5	77.5	78.0
Colombia	Mt	49.7	52.6	55.0	56.2	57.8	59.5	61.5
Indonesia	Mt	77.2	87.3	92.0	94.8	97.7	101.9	104.9
South Africa	Mt	70.6	70.8	75.0	76.6	78.0	81.8	84.3
United States	Mt	18.9	18.5	18.3	17.5	16.4	16.1	16.1
Other	Mt	119.6	117.8	115.5	110.0	109.4	112.4	112.8
		2002	2003	2004	2005	2006	2007	2008
		-03	-04	-05 f	-06 z	-07 z	-08 z	-09 z
Australia								
Production a	Mt	274.9	285.9	298.4	313.6	332.6	345.2	355.8
Domestic consumption	Mt	67.2	67.4	67.8	69.4	71.6	73.5	75.0
Volume of exports								
– thermal	Mt	99.9	106.7	108.9	116.5	124.7	128.5	130.5
– total	Mt	207.7	218.4	230.2	244.4	259.8	270.6	282.0
Value of exports								
Thermal								
– nominal	A\$m	4 448	4 372	6 260	7 421	7 292	6 956	6 652
– real b	A\$m	4 664	4 477	6 260	7 255	6 954	6 472	6 038

a Salable coal. b In 2004-05 Australian dollars. f ABARE forecast. z ABARE projection.

Sources: International Energy Agency; Coal Services Pty Limited; Queensland Government, Department of Natural Resources ; ABARE.

Source: Australian Bureau of Agricultural and Resource Economics

Why would Nestlé consider undertaking a project which does not provide a return on investment? As a major multinational company, Nestlé has a policy to reduce the environmental impact of its activities. The current coal boilers are not in compliance with Nestlé's Environmental Minimum Technical Requirements (NEMTR), which are part of the Nestlé Environmental Management System (NEMS). The head office was informed about this non-compliance, but due to high investment costs, proposed improvements, such as a fuel switch to diesel or installation of electrostatic precipitators or filters on the chimney, were never ap-



proved by the Nestlé head office. There is documentary evidence¹² of the decision by the Nestlé head office that demonstrates that there are no internal Nestlé requirements which make the proposed business-as-usual baseline an unlikely baseline scenario.

Potential revenues from the CDM would allow Nestlé to partially recover its costs involved in a project that would provide benefits to the local and global environment. Nestlé is interested in exploring the CDM alternative as one way of helping to pay for environmental projects. This is the first project submitted by Nestlé to CDM.

In Chile, some companies had switched from coal to natural gas. However, considering that coal is less expensive than natural gas, some companies have switched back to coal. Presenting this fuel switching project within the CDM will provide a substantial incentive not to switch back.

Besides economic and financial considerations, the project shows significant reduction in CO₂ equivalent emissions after switching to natural gas from coal, diesel and LPG. Our estimate of emissions over 21 years period would fall from 747,689 t CO₂ equivalent in the baseline case to 463,288 t CO₂ equivalent with the project, a reduction of 38%. These estimates take into account that some equipment would have reached the end of a 50-year life so that emissions reductions beyond that time for those pieces of equipment have not been considered.

¹² This information is presented in Annex 10 to this PDD.

B.5. Description of how the definition of the project boundary related to the baseline methodology is applied to the project activity:

For the purposes of this analysis, the project boundary encompasses the physical, geographical site of the plant. Schematically, Figure 4 shows the project boundary indicating energy flows into the boundary and fugitive methane emissions associated with coal and natural gas.

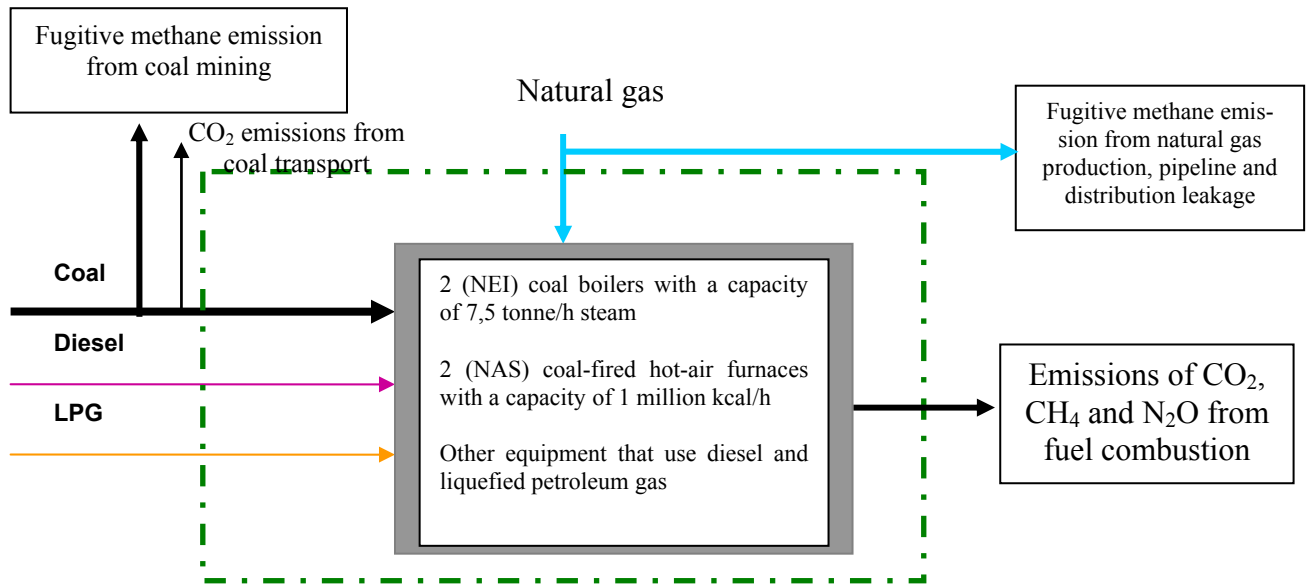


Figure 4. Project boundary for the Graneros Plant Fuel Switching project showing fuel flows into project site, and GHG emissions, covering periods both before and after project implementation.

Table 1 shows direct and indirect emissions both on- and off-site with respect to the project boundary shown in Figure 4.

Table 1: Direct and indirect emissions on- and off-site in the project and baseline scenarios

Emissions	Project Scenario	Baseline Scenario
Direct on-site	CO ₂ emissions associated with natural gas combustion at plant site. Methane (CH ₄) and nitrous oxide (N ₂ O) emissions from natural gas <i>combustion</i> at plant site. Methane (CH ₄) emissions from natural gas <i>leakage</i> at plant site.	CO ₂ emissions from coal and petroleum fuel combustion at plant site in the baseline. Methane (CH ₄) and nitrous oxide (N ₂ O) emissions from coal and petroleum fuel <i>combustion</i> at plant site in the baseline.
Direct off-site	None.	None.
Indirect on-site	Power plant CO ₂ emissions from electricity use at the plant site —excluded, since there is no change, with respect to the baseline, as a result of the project	Power plant CO ₂ emissions from electricity use at the plant site —excluded, since there is no change, with respect to the baseline, as a result of the project.
Indirect off-site	Methane (CH ₄) emissions from natural gas production, pipeline leakage (natural gas pipeline outside project site). If the source of natural gas is an Annex 1 party, then methane emissions in gas production and the part of the transmission pipeline in that country should be excluded. Other indirect off-site emissions would be associated with gas pipeline construction to bring natural gas to the project site area. This is not included, since there are likely to be many other users as well, and in each case there will be reduced CO ₂ emissions from fuel switching. These emissions are excluded.	Methane (CH ₄) emissions related to coal mining, provided the coal originates in a non-Annex 1 party. CO ₂ emissions from coal transport within the country of the project and in other non-Annex 1 parties.

These emissions are described in the proposed methodology (see Annex 3). For the specific project, the methodology is applied through a spreadsheet model: [MGM_BSL_NGP_ER.xls](#) to determine *ex ante* baseline and project emissions, and expected emissions reductions. Following project implementation, project emissions are determined from measurements. These same measurements are used to determine baseline emissions in a dynamic manner. Thus, *ex-post* baseline and project emissions, and emissions are determined from monitored data, as shown in Section D and the methodology described in Annex 4. These calculations are incorporated into the spreadsheet model [MGM_MVP_NGP_ER.xls](#).

B.6. Details of baseline development

B.6.1 Date of completing the final draft of this baseline section:

01/07/2003

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

Dr. Gautam S. Dutt and Ing. Ivana Cepon, MGM International, Ltda.
Junin 1655, 1 B
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Dr. Dutt and Ing. Cepon are not project participants.

C. Duration of the project activity / Crediting period

C.1 Duration of the project activity:

C.1.1. Starting date of the project activity:

The project is expected to be operating in January 2004.

The date of first CER-delivery is February 2004.

C.1.2. Expected operational lifetime of the project activity: 21 years

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

C.2.1. Renewable crediting period (at most seven (7) years per period)

C.2.1.1. Starting date of the first crediting period: 01/01/2004

C.2.1.2. Length of the first crediting period: 7 years

The baselines for this project will be re-evaluated every 7 years, in order to determine whether the key assumptions used for its formulation still hold appropriate.

C.2.2. Fixed crediting period (at most ten (10) years): **NOT SELECTED**

C.2.2.1. Starting date (DD/MM/YYYY):

C.2.2.2. Length (max 10 years):



D. Monitoring methodology and plan

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

As the monitoring methodology originally proposed with this PDD has been approved under the name of “*Industrial fuel switching from coal and petroleum to natural gas without extension of capacity and lifetime of the facility*” with the designation “AM0008”, we will apply the latter version for monitoring this project activity.

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

The Monitoring and Verification Plan describes the procedures for data collection, and auditing required for the project, in order to determine and verify emissions reductions achieved by the project. This project will require only very straightforward collection of data, described below, most of which is already collected routinely by the staff of Nestlé’s Graneros Plant, where the proposed CDM project is to be implemented.

GHG related data:

- Volume (m³) of natural gas used at the plant by each major equipment, and miscellaneous uses
- Quantities of any other fossil fuels still used in the plant, if any, after fuel switching, e.g. coal, diesel, LPG
- Estimation of methane emissions from natural gas production and pipeline leakage (internal and external to project site)
- Survey of the technology used at the Nestlé Graneros plant, including inventory of all fossil fuel using equipment; this survey will be conducted annually; (Not to be considered for emission reduction calculations)
- Energy efficiency of principal fuel using equipment
- Fuel prices of coal, petroleum fuels and natural gas

Non GHG-related data:

- Company’s internal health record: the company will monitor occupational health in order to detect if the project has substantially improved the health condition of its employees. This program will be based on internal health records; and records of absenteeism due to sickness. (Not to be considered for emission reduction calculations)
- In addition, the company will aim at maintaining its existing internal programs related to social and environmental quality, which also serve as indicators of the company’s commitment to social and environmental quality. Nestlé’s Environmental Minimum Technical Requirements (NEMTR) are part of the Nestlé Environmental Management System (NEMS). Annex 8 shows the main sustainability indicators used in this project. These are not relevant to emissions reduction calculations.



Annex 4 describes the procedure and equations for calculating project and (dynamic) baseline emissions from monitored data. For the specific project, the methodology is applied through a spreadsheet model: [MGM_MVP_NGP_ER.xls](#).



D.3. Data to be collected in order to monitor emissions from the project activity, and how this data will be archived:

ID number	Data type	Data variable	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/paper)	For how long is archived data to be kept?	Comment
D.3.1	Volume of natural gas consumed	MFC_{NG}	m ³	m	Month	100%	Paper (field record) Electronic (spreadsheet)	Paper: 1 year, Electronic: 7 years	
D.3.2	Quantity of coal used, if any after project implementation	MFC_{Coal}	kg	m	Month	100%	Paper (field record) Electronic (spreadsheet)	Paper: 1 year, Electronic: 7 years	
D.3.3	Quantity of diesel used, if any after project implementation	MFC_{Diesel}	liter	m	Month	100%	Paper (field record) Electronic (spreadsheet)	Paper: 1 year, Electronic: 7 years	
D.3.4	Quantity of LPG used, if any after project implementation	MFC_{LPG}	kg	m	Month	100%	Paper (field record) Electronic (spreadsheet)	Paper: 1 year, Electronic: 7 years	
D.3.5	Efficiency of principal equipment (2 boilers, 2 furnaces, 2 coffee roaster, and small equipment)	η	%	m	Year	Annual	Paper (field record) Electronic (spreadsheet)	Paper: 1 year, Electronic: 7 years	
D.3.6	Fuel prices (coal, diesel, LPG, natural gas)		\$/unit	m	At the end of each crediting period	Every 7 years	Paper (field record) Electronic (spreadsheet)	21 years	

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

Electricity consumption at the project site is responsible for indirect emissions of CO₂ at power plants based on fossil fuels. However, electricity consumption is not affected by project activity, which involves fuel shifting for boilers and furnaces used to generate heat. Thus we do not expect electricity consumption or associated emissions to be affected by the project activity. Thus, such emissions are not considered.

D.5. Relevant data necessary for determining the baseline of anthropogenic emissions by sources of GHG within the project boundary and identification if and how such data will be collected and archived.

The baseline emissions are determined in a dynamic manner from monitored values. All data needed for determining this dynamic baseline are listed above in section D.3. Thus, no additional data are needed to define the baseline.



D.6. Quality control (QC) and quality assurance (QA) procedures are being undertaken for data monitored (data items in tables contained in section D.3., D.4. and D.5 above, as applicable)

Nestlé Chile S.A. has a series of internal procedures with respect to quality control. Nestlé Chile S.A. will use these procedures to ensure that data collected for the project are subject to the most rigid quality control procedures. See details in Annex 9.

Data	Uncertainty level of data (High/Medium/Low)	Are QA/QC procedures planned for these data?	Outline explanation why QA/QC procedures are or are not being planned.
<i>D.3.1</i>	<i>Low</i>	<i>Yes</i>	These data will be directly used for calculation of emissions reductions
<i>D.3.2</i>	<i>Low</i>	<i>Yes</i>	These data will be directly used for calculation of emissions reductions
<i>D.3.3</i>	<i>Low</i>	<i>Yes</i>	These data will be directly used for calculation of emissions reductions
<i>D.3.4</i>	<i>Low</i>	<i>Yes</i>	These data will be directly used for calculation of emissions reductions
<i>D.3.5</i>	<i>Low</i>	<i>Yes</i>	These data will be directly used for calculation of emissions reductions
<i>D.3.6</i>	<i>Low</i>	<i>No</i>	These data will be used for revalidation of baseline and additionality

D.7 Name of person/entity determining the monitoring methodology:

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

Dr. Dutt and Ing. Cepon are not project participants.



E. Calculation of GHG emissions by sources

E.1 Description of formulae used to estimate anthropogenic emissions by sources of greenhouse gases of the project activity within the project boundary: (for each gas, source, formulae/algorithm, emissions in units of CO₂ equivalent)

Carbon dioxide emissions from combustion

While after project implementation, only natural gas is expected to be used, there may remain some coal, diesel or LPG use even in the project scenario. Thus, the calculations allow for this possibility.

Estimated carbon dioxide emissions, E, are given by:

$$E (\text{tonne CO}_2 / \text{year}) = \sum_j E_j (\text{tonne CO}_2 / \text{year}) \quad (\text{Eq. 1})$$

where E_j = CO₂ emissions per year from fuel j , calculated as:

$$E_j (\text{tonne CO}_2 / \text{year}) = \frac{AFC_j \cdot CV_j \cdot EF_j \cdot 4.1868 \text{ J / cal}}{10^6} \quad (\text{Eq. 2})$$

where AFC_j = annual consumption of fuel j ; (1000 m³ of natural gas, tonne of coal, tonne of diesel, tonne of LPG)

CV_j = lower heating value of fuel j (kcal/m³ for natural gas or kcal/kg for coal, diesel or LPG)

EF_j = CO₂ emission factor of fuel j (kg CO₂/GJ, lower heating value basis)

Methane emissions from combustion

A certain amount of methane is generated in the combustion of most fuels. For industrial boilers, IPCC 1996 Guidelines for National Greenhouse Gas Inventories, Vol. 3, Table 1-16, p. 1.54, provides estimates for coal and natural-gas fired boilers. For the small equipment that use Diesel, commercial source equipment is considered appropriate as in IPCC 1996, Table 1-19, p. 1.57. For LPG, only data for residential propane /butane furnaces were available in IPCC 1996, Table 1-18, p. 1.56. Estimates of methane emissions factors used here, are given below

Source	Methane emissions, kg /TJ energy input (lower heating value basis)
Coal-fired boilers	1.0
Diesel (Distillate fuel oil)	0.7
LPG (Propane/butane furnaces)	1.1
Natural gas-fired boilers	1.4

The only fuel relevant for the project case is natural gas, though provision is made in the MVP for circumstances in which coal, diesel and LPG might be used after project implementation.

Estimated methane emissions from combustion, $E_{met\ comb}$ (tonne CH_4 /year), are given by:

$$E_{met\ comb} (\text{tonne } CH_4 / \text{year}) = \sum_j E_{met\ comb_j} (\text{tonne } CH_4 / \text{year}) \quad (\text{Eq. 3})$$

where $E_{met\ comb_j}$ = CH_4 emissions per year from fuel j , calculated as:

$$E_{met\ comb_j} (\text{tonne } CH_4 / \text{year}) = \frac{AFC_j \cdot CV_j \cdot MEF_j \cdot 4.1868 \text{ J/cal}}{10^9} \quad (\text{Eq. 4})$$

where AFC_j = annual consumption of fuel j ; (1000 m^3 of natural gas or tonne of coal, diesel or LPG)

CV_j = lower heating value of fuel j (kcal/ m^3 of natural gas or kcal/kg of coal, diesel or LPG)

MEF_j = methane emission factor of fuel j (kg CH_4 /TJ, lower heating value basis)

Convert to units of carbon dioxide equivalent emissions

$$E_{equiv\ met\ comb} (\text{tonne } CO_2 - \text{equiv} / \text{year}) = E_{met\ comb} (\text{tonne } CH_4) \cdot GWP(CH_4) \quad (\text{Eq. 5})$$

where $E_{equiv\ met\ comb}$ = CO_2 -equiv emissions per year, tonnes

$$GWP(CH_4) = 21$$

We may apply this formula to methane emissions from combustion, using the emissions factor given in the table above, to coal consumption (in the baseline scenario) and equivalent natural gas consumption in the first project year. We obtain CO_2 -equivalent emissions of 7 tonnes for coal and other fuels (in the baseline) and 9 tonnes for natural gas (in the project case). See [MGM_BSL_NGP_ER.xls](#), sheet "Natural gas". This is insignificant compared to total emissions, which add up to 32,580 tonnes and 19,974 tonnes CO_2 equivalent in the baseline and project cases respectively, for the first project year. Thus the GHG emissions from methane in combustion insignificant in each case. *While methane emissions in combustion are included in this project, they could well have been neglected.*

Nitrous oxide emissions from combustion

A certain amount of nitrous oxide is also generated in the combustion of most fuels. For industrial boilers, *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Reference Manual*, Table 1-16, p. 1.54, provides a value for bituminous coal, but not for LPG, natural gas or diesel. A value for natural gas is given only for “commercial source”, in IPCC 1996, Table 1-19, p. 1.57. For diesel and LPG, the value used corresponds to distillate fuel oil, also for commercial source, in IPCC, 1996, Table 1-19, p. 1.57. The values used are shown below:

Source	Nitrous oxide emissions, kg /TJ energy input (lower heating value basis)
Coal-fired boilers	1.6
Diesel or LPG (distillate fuel oil)	0.4
Natural gas-fired boilers	2.3

Estimated nitrous oxide emissions from combustion, $E_{N_2O\ comb}$ (tonne N_2O /year), are given by:

$$E_{N_2O\ comb} (\text{tonne } N_2O / \text{year}) = \sum_j E_{N_2O\ comb_j} (\text{tonne } N_2O / \text{year}) \quad (\text{Eq. 6})$$

where $E_{N_2O\ comb} = N_2O$ emissions per year from fuel j , calculated as:

$$E_{N_2O\ comb_j} (\text{tonne } N_2O / \text{year}) = \frac{AFC_j \cdot CV_j \cdot NEF_j \cdot 4.1868 J / cal}{10^9} \quad (\text{Eq. 7})$$

where AFC_j = annual consumption of fuel j ; (1000 m³ of natural gas or tonne of coal, diesel or LPG)

CV_j = lower heating value of fuel j (kcal/m³ for natural gas or kcal/kg for coal, diesel or LPG)

NEF_j = N_2O emission factor of fuel j (kg N_2O /TJ, lower heating value basis)

Convert to units of carbon dioxide equivalent emissions

$$E_{equiv\ N_2O\ comb} (\text{tonne } CO_2 - \text{equiv} / \text{year}) = E_{N_2O\ comb} (\text{tonne } N_2O) \cdot GWP(N_2O) \quad (\text{Eq. 8})$$

where $E_{equiv\ N_2O\ comb} = CO_2$ -equiv emissions per year, tonnes

$$GWP(N_2O) = 310$$

While the absolute value of the emissions factor for nitrous oxide in kg/TJ is similar for this gas as for methane, the CO₂ equivalent is much higher, because of the considerably higher GWP of N₂O. Thus, N₂O emissions for the first project year in the baseline and project scenarios are 161 and 226 tonnes CO₂-equivalent respectively. See [MGM_BSL_NGP_ER.xls](#), sheet “Natural gas”. These are still insignificant compared to total emissions, which add up to 32,580 tonnes and 19,974 tonnes CO₂ equivalent in the baseline and project cases respectively, for the first project year. (The CO₂-equivalent emissions amount to about 0.5% and 1.1% of the total.)

E.2 Description of formulae used to estimate leakage, defined as: the net change of anthropogenic emissions by sources of greenhouse gases which occurs outside the project boundary, and that is measurable and attributable to the project activity: (for each gas, source, formulae/algorithm, emissions in units of CO₂ equivalent)

The project involves switching from coal and petroleum fuels to natural gas. There are fugitive emissions of methane associated with natural gas supply. These occur in gas production (at the gas well) as well by leakage from the pipeline supplying the project site. These are direct off-site emissions or “leakage”. There would also be fugitive emissions from the natural gas distribution network within the project site. For simplicity in calculations, we consider all of these fugitive methane emissions to be indirect off-site.

Methane leakage from natural gas production. Natural gas that would be used in the project site is extracted in Argentina. However, country and well-specific data on methane emissions from natural gas production are not available for Argentina. We thus use region specific values indicated in the IPCC Guidelines for National Greenhouse Gas Inventories Volume 3: Reference Manual (1996). Table 1-64 page 1.131 indicates values of 39,590 to 96,000 kg/PJ of gas *produced*. Since gas leaks are a small part of gas production, we may take the leakage to be approximately the same as kg per PJ of gas *consumption*, as well. We assume an average value of 70,000 kg/PJ of gas consumed at the project site. This is the same as 0.07 kg/GJ of gas consumed. While this methane leakage is outside the project boundary, and indeed outside the country, we still need to account for it, since it takes place in another non-Annex 1 party.

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

Considering gas production, transport and distribution, we consider a methane emissions factor from leakage to be (0.07 + 0.23) or 0.30 kg/GJ gas consumption.



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

$$E_{fug} \text{ (tonne CH}_4 \text{ / year)} = \frac{AFC_{NG} \cdot CV_{NG} \cdot MLR \cdot 4.1868 \text{ J / cal}}{10^6} \quad \text{(Eq. 9)}$$

where AFC_{NG} = annual natural gas consumption (1000 m³ of natural gas)
 CV_{NG} = lower heating value of natural gas (kcal/m³)
 MLR = Methane leakage rate, 0.30 kg CH₄/GJ (see above)

Convert to units of carbon dioxide equivalent emissions

$$E_{equiv \ fug} \text{ (tonne CO}_2 \text{ - equiv / year)} = E_{fug} \cdot GWP \text{ (CH}_4\text{)} \quad \text{(Eq. 10)}$$

where $E_{equiv \ fug}$ = CO₂-equiv emissions, tonnes per year,
 $GWP \text{ (CH}_4\text{)} = 21$

E.3 The sum of items in E.1 and E.2 represent the total project activity emissions:

$$E_{total} \text{ (tonne CO}_2 \text{ - equiv / year)} = E + E_{equiv \ met \ comb} + E_{equiv \ N_2O \ comb} + E_{equiv \ fug} \quad \text{(Eq. 11)}$$

where E refers to CO₂ emissions from combustion (of natural gas and any other fuel), $E_{equiv \ met \ comb}$ and $E_{equiv \ N_2O \ comb}$ refer to CO₂-equivalent emissions from methane and nitrous oxide produced in combustion, and $E_{equiv \ fug}$ to methane leakage from natural gas production, transport and distribution.

E.4 Description of formulae used to estimate the anthropogenic emissions by sources of greenhouse gases of the baseline: (for each gas, source, formulae/algorithm, emissions in units of CO₂ equivalent)

Carbon dioxide emissions from combustion

In the baseline, coal, diesel and LPG are used. The equations are similar to Eq (1) and (2).

Estimated carbon dioxide emissions from fuel combustion in the baseline, BE (tonne CO₂/year) is given by:

$$BE(\text{tonne CO}_2 / \text{year}) = \sum_j BE_j(\text{tonne CO}_2 / \text{year}) \quad (\text{Eq. 12})$$

where BE_j = CO₂ emissions per year from fuel j , calculated as:

$$BE_j(\text{tonne CO}_2 / \text{year}) = \frac{AFC_j \cdot CV_j \cdot EF_j \cdot 4.1868 \text{ J / cal}}{10^6} \quad (\text{Eq. 13})$$

where AFC_j = annual consumption of the fuel in baseline (tonne of coal, diesel, or LPG)

CV_j = lower heating value of fuel (kcal/kg of coal, diesel or LPG)

EF_j = emission factor of the fuel used in the plant (kg CO₂/GJ, lower heating value basis)

Methane emissions in combustion

Methane emissions from combustion, in the baseline, are similar to Eq (3) to (5) as in the project case, except that in the baseline, the emissions are principally from coal with some contribution from diesel and LPG. As discussed in Section E.1, IPCC (1996) provided estimates of emissions factors for methane emissions in combustion. The relevant emissions factors are given below:

Source	Methane emissions, kg /TJ energy input (lower heating value basis)
Coal-fired boilers	1.0
Diesel (Distillate fuel oil)	0.7
LPG (Propane/butane furnaces)	1.1

Estimated baseline methane emissions from combustion, $BE_{met\ comb}$ (tonne CH_4 /year), are given by:

$$BE_{met\ comb} (\text{tonne } CH_4 / \text{year}) = \sum_j BE_{met\ comb\ j} (\text{tonne } CH_4 / \text{year}) \quad (\text{Eq. 14})$$

where $BE_{met\ comb\ j}$ = CH_4 emissions per year from fuel j , calculated as:

$$BE_{met\ comb\ j} (\text{tonne } CH_4 / \text{year}) = \frac{AFC_j \cdot CV_j \cdot MEF_j \cdot 4.1868 \text{ J / cal}}{10^9} \quad (\text{Eq. 15})$$

where AFC_j = annual consumption of fuel j (tonne of coal, diesel or LPG)

CV_j = lower heating value of fuel j (kcal/kg of coal, diesel or LPG)

MEF_j = methane emission factor of fuel j (kg CH_4 /TJ, lower heating value basis)

Convert to units of carbon dioxide equivalent emissions

$$BE_{equiv\ met\ comb} (\text{tonne } CO_2 - \text{equiv} / \text{year}) = BE_{met\ comb} (\text{tonne } CH_4) \cdot GWP(CH_4) \quad (\text{Eq. 16})$$

where $BE_{equiv\ met\ comb}$ = CO_2 -equiv emissions per year, tonnes

$$GWP(CH_4) = 21$$

Nitrous oxide emissions from combustion

Nitrous oxide emissions from combustion, in the baseline, are similar to Eq (6) to (8) for the project case, except that in the baseline, the emissions are principally from coal with some contribution from diesel and LPG. As discussed in Section E.1, IPCC (1996) provided estimates of emissions factors for nitrous oxide emissions in combustion. The following are relevant for the baseline:

Source	Methane emissions, kg /TJ energy input (lower heating value basis)
Coal-fired boilers	1.6
Diesel or LPG	0.4

Estimated nitrous oxide emissions from combustion, $BE_{N_2O\ comb}^{comb}$ (tonne N_2O /year), are given by:

$$BE_{N_2O\ comb}(\text{tonne } N_2O/\text{year}) = \sum_j BE_{N_2O\ comb_j}(\text{tonne } N_2O/\text{year}) \quad (\text{Eq. 17})$$

where $BE_{N_2O\ comb} = N_2O$ emissions per year from fuel j , calculated as:

$$BE_{N_2O\ comb_j}(\text{tonne } N_2O/\text{year}) = \frac{AFC_j \cdot CV_j \cdot NEF_j \cdot 4.1868\text{ J/cal}}{10^9} \quad (\text{Eq. 18})$$

where AFC_j = annual consumption of fuel j ; (tonne of coal, diesel or LPG)

CV_j = lower heating value of fuel j (kcal/kg for coal, diesel or LPG)

NEF_j = N_2O emission factor of fuel j (kg N_2O /TJ, lower heating value basis)

Convert to units of carbon dioxide equivalent emissions

$$BE_{equiv\ N_2O\ comb}(\text{tonne } CO_2\text{-equiv}/\text{year}) = BE_{N_2O\ comb}(\text{tonne } N_2O) \cdot GWP(N_2O) \quad (\text{Eq. 19})$$

where $BE_{equiv\ N_2O\ comb} = CO_2$ -equiv emissions per year, tonnes

$$GWP(N_2O) = 310$$

Methane emissions from coal mining

Methane is released from coal mining operations. Thus coal consumption (in the baseline) is associated with methane emissions.

Methane emissions from coal mining, BE_{fug} (tonnes CH_4 /year) are given by:

$$BE_{fug} \text{ (tonne } CH_4 \text{ / year)} = \frac{AFC \cdot MCEF}{10^3} \quad (\text{Eq. 20})$$

where AFC = annual coal consumption (tonnes of coal)

$MCEF$ = emission factor of methane from coal mining (kg CH_4 /tonne of coal)

$$\frac{15.6 \text{ m}^3 \text{ / tonne coal (underground mining)} \cdot 0.67 \text{ kg / m}^3 \text{ (methane density)}}{10^3}$$

(IPCC Guidelines for National Greenhouse Gas Inventories Reference Manual (1996), Table 1-54, p 1.105, provides a range of estimates for methane emissions from coal mining underground: 10 to 25 m^3 /tonne. Moreover, Chile imports coal from Australia, and IPCC cites Australian sources that report methane emissions to be 15.6 m^3 /tonne coal, which is the value we consider here, along with a methane density of 0.67 kg/m^3 at 1 atm. and 20 C.)

Convert to units of carbon dioxide equivalent emissions

$$BE_{equiv-fug} \text{ (tonne } CO_2 \text{ - equiv / year)} = BE_{fug} \cdot GWP(CH_4) \quad (\text{Eq. 21})$$

where $BE_{equiv-fug}$ = CO_2 -equiv emissions, tonnes per year,

$$GWP(CH_4) = 21$$

Note that in this case, the source of coal is Australia, an Annex 1 party. Thus these emissions and their reductions are not counted in the emissions reductions to be credited. (We may denominate them Gift Emissions Reductions.)

CO₂ emissions from coal transport

Coal is transported by truck from a Chilean port to the industrial plant. Previously, coal is transported by ship from an Australian port to the Chilean port and by truck from the mine to the port in Australia. The CO₂ emissions associated with each leg of coal transport are analysed below.

A) CO₂ emissions from truck transport of coal from port to factory

Data provided by Nestlé:

Coal used at the Nestlé Graneros plant is imported from Australia.
 Coal is supplied by truck from the Puerto de Ventana, a port on the Pacific, to the Nestlé Graneros plant, a distance of 259 km away.
 Distance travelled by truck: 259 km each way
 Truck fuel consumption: 2.3 km/litre
 Fuel consumption per round trip: $2 \times 259 / 2.3 = 225$ litres (diesel fuel)
 Coal transported per trip: 28 tonnes
 Fuel consumption: 225 litres per 28 tonnes of coal = 8.04 litres per tonne coal

CO₂ emissions from coal transport by truck is given by:

$$BE_{transport}(\text{tonne CO}_2 - \text{equiv/tonne coal}) = TFSC \cdot DD \cdot CVD \cdot EFD \quad (\text{Eq. 22})$$

where

TFSC = truck freight specific energy consumption (km/litre) = 8.04 litre/tonne coal

DD = diesel density (kg/litre) = 0.849 kg/litre

CVD = lower heating value of fuel (MJ/kg) = 43.33 MJ/kg, and

EFD = CO₂ emissions factor from diesel consumption (kg CO₂/GJ, lower heating value basis) = 74.07
 t CO₂ / TJ = 0.07407 kg CO₂ / MJ

$$E_{transport}(\text{tonne CO}_2 - \text{equiv/tonne coal}) = 8.04 \cdot 0.849 \cdot 43.33 \cdot 0.07407$$

$$= E_{transport}(\text{tonne CO}_2 - \text{equiv/tonne coal}) = 22.08 \text{ kgCO}_2 \text{ per tonne of coal}$$

An emissions factor of 22.1 kg CO₂ per tonne of coal consumed at Nestlé Graneros Plant is considered in this PDD and associated analysis.

Total coal consumption (in the baseline) over 21 years: 310,650 tonnes

Total CO₂ emissions from truck transport over 21 years = 6,865 tonnes CO₂.



B) CO₂ emissions from coal shipped from Australian port to Chilean port

While these emissions are not counted in this PDD, since they correspond to emissions from international bunker fuel consumption, and thus not attributable to any party to the UNFCCC, we show that the emissions are significant and should be considered in the future.

We assume a typical ship freight fuel intensity of 400 Btu/tonne mile (Source: ACEEE, *Transportation and Energy: Strategies for a Sustainable Transportation System*. American Council for an Energy-Efficient Economy.)

This is equivalent to

$$= \frac{400 \cdot 1055 J}{1000 kg \cdot 1.6 km} = 264 J / kg km = 0.264 MJ / tonne - km$$

Note here that ship freight is highly fuel efficient, compared to truck transport or indeed almost any other form of transport.

We assume the ship consumes diesel fuel, and consider, as before,

LHV diesel = 43.33 MJ/kg

CO₂ emissions factor of diesel = 0.07407 kg CO₂ /MJ

Thus CO₂ emissions factor *per tonne-km*

$$= 0.07407 \cdot 0.264 = 0.01926 kgCO_2 / tonne - km$$

Thus, CO₂ emissions per tonne of coal transported from Australia to Chile (say, 8000 km)

$$= 0.01926 \cdot 8000 = 154 kgCO_2 / tonne coal$$

Total coal consumption (in the baseline) over 21 years: 310,650 tonnes.

Total CO₂ emissions from sea transport of coal = 47,840 tonnes CO₂.

While these emissions (ship freight) are not being accounted in this PDD, we should note that the magnitude is *seven times* that of the emissions corresponding to truck transport within Chile, which *are* being accounted for in this PDD.

C) CO₂ emissions for coal transport from Australian coal mine to Australian port

Coal is shipped by truck freight from the Australian mine to port. These emissions have not been considered here, as a conservative assumption. Since Australia is an Annex 1 party, these emissions reductions would appear in its national inventory. As of this date, Australia has not ratified the Kyoto Protocol, however. These emissions would also fall in the Gift Emissions Reductions category.



MGM considers that emissions from transport in international space should be included, since these emissions also contribute to the greenhouse effect, and their reduction is a mitigation measure.

Other sources of coal. At present, the project is fueled by coal imported from Australia. In the baseline scenario considered here, we assume that this would continue to be the case in the absence of the project. The question may be raised: what if the source of coal were changed in the baseline scenario? How would this affect the baseline emissions? The main South American source of coal is Colombia, and this might be an alternative fuel source. However, in this case, coal transport would include surface movement in both Colombia and Chile, as well as maritime transport involving CO₂ emissions from international bunker fuel combustion. Since both Colombia and Chile are non-Annex 1 parties, both of which have ratified the Kyoto Protocol, the emissions in the baseline case from coal transport would be greater, with a larger part in non-Annex 1 countries. Thus, the case considered here (Australian coal) is a conservative scenario in the sense that it reduces CO₂ emissions accounted for in our calculations.

Total baseline emissions BE_{total} (tonnes CO₂-equivalent/year) are determined as the sum of the component emissions considered in Section E.4, and given by:

$$BE_{total} (\text{tonne CO}_2 - \text{equiv} / \text{year}) = BE + BE_{equiv \text{ met comb}} + BE_{equiv \text{ N}_2\text{O comb}} + BE_{transport} \quad (\text{Eq. 23})$$

where BE refers to CO₂ emissions from combustion, $BE_{equiv \text{ met comb}}$ and $BE_{equiv \text{ N}_2\text{O comb}}$ refer to CO₂-equivalent emissions from methane and nitrous oxide produced in combustion, and $BE_{transport}$ refers to CO₂ production in the transport of coal by truck from the Chilean port to Nestlé. Coal mining methane emissions are not included since they would take place in an Annex 1 country.

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

$$ER (\text{tonne CO}_2 - \text{equiv} / \text{year}) = BE_{total} - E_{total} \quad (\text{Eq. 24})$$

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

NOTE: for more details please see spreadsheets [MGM_BSL_NGP_ER.xls](#). Results are summarized below. As stated in Section B for the baseline, we are not claiming any emissions reduction for a boiler and two coffee roasters beyond their 50-year life.

**Baseline and project emissions and reductions in the first crediting period
(tonnes CO₂ equiv/year)**

year	year	Baseline emissions t CO ₂ equiv/year	Project emissions t CO ₂ equiv/year	Emissions reductions t CO ₂ equiv/year
1	2004	32,580	19,974	12,605
2	2005	33,921	20,796	13,124
3	2006	34,951	21,344	13,607
4	2007	36,390	22,223	14,167
5	2008	37,888	23,138	14,750
6	2009	26,297	16,170	10,127
7	2010	27,379	16,836	10,544
Total		229,405	140,480	88,924

**Baseline and project emissions and reductions during the 21-year crediting period
(tonnes CO₂ equiv/year)**

year	year	Baseline emissions t CO ₂ equiv/year	Project emissions t CO ₂ equiv/year	Emissions reductions t CO ₂ equiv/year
1	2004	32,580	19,974	12,605
2	2005	33,921	20,796	13,124
3	2006	34,951	21,344	13,607
4	2007	36,390	22,223	14,167
5	2008	37,888	23,138	14,750
6	2009	26,297	16,170	10,127
7	2010	27,379	16,836	10,544
8	2011	28,507	17,529	10,978
9	2012	29,680	18,250	11,430
10	2013	30,416	18,592	11,823
11	2014	31,668	19,784	11,884
12	2015	32,972	20,598	12,373
13	2016	34,329	21,446	12,883
14	2017	35,742	22,329	13,413
15	2018	37,214	23,249	13,965
16	2019	38,746	24,206	14,540
17	2020	40,341	25,202	15,139
18	2021	42,002	26,240	15,762
19	2022	43,731	27,320	16,411
20	2023	45,531	28,445	17,086
21	2024	47,406	29,616	17,790
Total		747,689	463,288	284,400



Estimates of emissions reductions summary	
crediting period	tonnes of CO₂ equiv
7-year (2004 to 2010)	88,942
21-year	284,400

F. Environmental impacts

F.1. Documentation on the analysis of the environmental impacts, including trans-boundary impacts

The substitution of coal, diesel and LPG by natural gas has positive environmental impact on several grounds.

Eliminating coal use at the plant reduces coal consumption. This reduces environmental impact at the mining site. Moreover, the environmental impact of coal transport (boat and truck) from mine to project site is eliminated. Finally, coal burning produces a number of gaseous and particulate emissions which are local air pollutants. The particulate emissions are almost completely eliminated by switching to natural gas. Gaseous pollutants are also substantially reduced since natural gas burns more cleanly than coal.

In the case of diesel, there are environmental impacts from petroleum extraction, refining and transport, though these are generally less than for coal. These are reduced by switching from diesel to natural gas. Burning diesel fuel at the project site also produces gaseous and some particulate emissions, which are also substantially reduced when using natural gas.

Finally, in the case of LPG, there are environmental impacts from petroleum extraction, LPG production and transport, all of which are eliminated when LPG is replaced by natural gas. The combustion of LPG and natural gas produces similar amounts of pollutants, so that there are no additional benefits in this case.

It should be kept in mind that the current fuel use is dominated by coal, so that environmental benefits are significant.

The project implementation involves the construction of a gas distribution network at the Graneros plant site and the installation of equipment permitting the use of natural gas. The environmental impact of these activities are expected to be insignificant.

F.2. If 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 that has been undertaken in accordance with the procedures as required by the host Party.

No significant negative environmental impact is expected from project activities and an environmental impact study is not required by Chilean authorities.

G. Stakeholders comments

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

The process followed to collect stakeholder comments of the Graneros Plant Fuel Switching Project was through a survey.

The following set of questions was sent to stakeholders, during June 2003:

1. Do you believe that the socio-economic situation of the Region VI will improve due to the implementation of Graneros Plant Fuel Switching project?
2. Is the implementation of project able to improve the environmental situation in the Region?
3. How does the development of the project affect you (positively or negatively) or on your environment?
4. Would you recommend private companies or authorities to develop projects of this nature?
5. Do you think “Graneros Plan Fuel Switching Project” will contribute to the Sustainable Development of Chile?
6. Any additional comments you would like to make.

The questionnaire was sent to the following persons:

Name	Position	Company/Institution
Mr. Carlos Bravo	Mayor	Municipality of Region VI
Ms. Heydy Leiva H.	Secretary	Ministerial Regional Secretary - Ministry of Health
Mr. Roberto Bravo	Sub-Director	Direction of Environmental Health - Service of Health
Mr. Héctor González	Surrogate Director	Environment National Commission
Mr. Juan Pablo Díaz	Mayor	Municipality of Graneros
Dr. Raúl O’Ryan	Director	Management and Environment Economy Program - Department of Industrial Engineer University of Chile
Dr. Jaime Parada	General Manager	DEUMAN – Environmental and engineer consulting
Ambassador José Manuel Ovalle	Director	Environment Department - Ministry of Affairs
Dr. Luis Cifuentes	Professor	Pontificia Universidad Católica de Chile



G.2. Summary of the comments received:

The following table show a synthesis of the comments received at the moment:

Question	Mr. Juan Pablo Díaz Burgos, Mayor Municipality of Graneros	Dr. Jaime Parada Director of DEUMAN Ingenieros
1	Yes, because the implementation of this project will improve the air quality in the municipality and the region in general	Yes, because the implementation of this project will improve the air quality in the municipality and the region in general
2	Yes, because this kind of project will provide incentives to other companies to use clean technology which would improve product quality while being environment friendly.	Yes
3	Project implementation is very positive since the local population has been affected on several occasions by air pollution emanating from the chimneys operating on coal. This affects not only air quality but also the health of the population.	Project implementation is very positive.
4	Yes, because it promotes the implementation of clean technologies and this permits an improvement in the environment and improved production.	Yes, because it promotes the implementation of clean technologies and this permits an improvement in the environment and sustainable development
5	Yes	Yes
6	Graneros and its community will be greatly benefited by this project. Nestlé will obtain benefits in industrial production and there will be great environmental benefits for the community.	Graneros town will be benefited by this project.

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

Only two comments were received, and they were very positive for project implementation.

Nestlé invited comments from other stakeholders, after the PDD was published at the DNV website during the validation process:

<http://www2.dnv.com/certification/ClimateChange/Projects/ProjectList.asp>

No further comments were received.



Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

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Annex 2

Information regarding public funding

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



Annex 3

New baseline methodology

(The baseline for a CDM project activity is the scenario that reasonably represents the anthropogenic emissions by sources of greenhouse gases that would occur in the absence of the proposed project activity. A baseline shall cover emissions from all gases, sectors and source categories listed in Annex A of the Kyoto Protocol within the project boundary. The general characteristics of a baseline are contained in para. 45 of the CDM M&P.)

For guidance on aspects to be covered in the description of a new methodology, please refer to the UNFCCC CDM web site.

Please note that the table “Baseline data” contained in Annex 5 is to be prepared parallel to completing the remainder of this section.)

Annex 4

New monitoring methodology

(Please provide a detailed description of the monitoring plan, including the identification of data and its quality with regard to accuracy, comparability, completeness and validity)



Annex 5

Table: Baseline data

See [MGM_BSL_NGP_ER.xls](#).

