PONTIFICIA UNIVERSIDAD CATOLICA DE CHILE

ESCUELA DE INGENIERIA

ELECTRIC DEMAND OF THE COPPER MINING INDUSTRY AND REDUCTION COSTS FOR CARBON EMISSIONS IN THE SING

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Thesis submitted to the Office of Research and Graduate Studies in partial fulfillment of the requirements for the Degree of Master of Science in Engineering

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Santiago de Chile, March 13th 2008

To my family, to Paulina and to my friends. Thanks for your unconditional support.

ACKNOWLEDGEMENTS

I would like to thank Professor Gustavo Lagos for his permanent trust in my work and for the invaluable support given through the duration of this study. I would also like to thank Professor Luis Cifuentes for his great review comments and ideas, and Professor Hugh Rudnick for his big help with the electricity market topics.

A special thanks to all the people that contributed in this study. To Gladys Barraza, Roberto Aguilera and John Tilton from Catholic University of Chile. To Sara Pimentel from COCHILCO, Jorge Venegas from CDEC-SING, Marcelo Velasco from IM2, and to the Advisory Panel of Catholic University's Mineral Economics Program. To Jasmine Sims for her grammar review.

Finally, I would like to thank my parents, Candela and Robert; my sisters, Magdalena and Valentina; and Paulina, for all their affection and support.

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RESUMEN

Este estudio presenta una metodología interdisciplinaria que mediante la aplicación de conceptos mineros, eléctricos, económicos y ambientales, entrega la proyección de las emisiones de carbono del SING y de los costos de reducción bajo diversos escenarios.

Las emisiones de carbono asociadas al consumo eléctrico de la Industria Minera del Cobre conectada al SING se estiman para el período 2000-2012. Se estiman además los costos de reducción de emisiones para distintos escenarios.

La estimación de las emisiones de carbono se basa en la demanda eléctrica de la Industria Minera del Cobre, la cual se estima a partir de proyecciones de la producción de cobre de cada mina y de coeficientes de consumo unitario de electricidad de los procesos de una mina promedio conectada al SING; y se basa también en un modelo operacional y ambiental del conjunto de centrales actuales y proyectadas del SING.

Los escenarios evaluados corresponden a la incorporación de energías renovables a la matriz energética, el uso de tecnologías avanzadas en las futuras centrales a carbón/petcoke, y la operación del sistema con emisiones restringidas.

Se espera un aumento en las emisiones de carbono asociadas al consumo eléctrico de la Industria Minera del Cobre de un 130% entre 2000 y 2012. Un 66.1% de este aumento se deberá al aumento de la producción de cobre y un 33.9% al mayor factor de emisión de la matriz energética de 2012. El uso de tecnologías más avanzadas en las futuras centrales puede traer ahorros al sistema además de menores emisiones. El reemplazo de carbón por gas puede traer por sí sólo una reducción de un 12% en las emisiones de 2012 a un costo menor a US$23 por tonelada de CO_2 reducida.

Palabras Claves: Emisiones de carbono; Costos de mitigación de carbono; Minería del cobre; Chile

ABSTRACT

This study presents an interdisciplinary methodology that, by using mining, electric, economic and environmental concepts, projects the carbon emissions in the SING and allows the estimation of reduction costs for these emissions.

Carbon emissions caused by the electricity consumption of the Chilean Copper Mining Industry connected to the SING are estimated for the period between 2000 and 2012. In addition, costs of the reduction of these emissions reduction are estimated for different scenarios.

The estimation of carbon emissions is based on the Copper Mining Industry's electricity demand by using copper production projections for each mine, combined with the coefficients of unitary electricity consumptions of an average copper mine connected to the SING. This estimation is also based on an operational and environmental model of the current and planned power plants of the SING.

Evaluated scenarios include: the incorporation of renewable energy into the energy mix; the use of more advanced technologies on the future coal/petcoke-fired power plants, and the system's operation with constrained carbon emissions.

Carbon emissions caused by the electricity consumption of the Copper Mining Industry are expected to rise 130% between 2000 and 2012. 66.1% of this increase will be due to the higher copper production, 33.9% due to the higher emission factor of 2012's energy mix. The use of more advanced technologies in future power plants would bring to the system not only emissions reductions, but saving costs. Coal by gas substitution can achieve on its own a reduction of 12% of 2012's emissions at a cost lower than US$ 23 per ton of CO_2.
Keywords: Carbon emissions; Carbon mitigation costs; Copper mining; Chile

I. INTRODUCTION

Climate Change is expected to have a serious impact on growth and development (U.K. HM Treasury, 2006), and there is convincing evidence showing that most of the global warming observed in the last 50 years has its origin in human activities (IPCC, 2001b).

Climate Change presents both risks and opportunities to Industry (Carbon Disclosure Project, 2006), and nowadays it has become a concert to the Industry on a fundamental level (Carbon Disclosure Project, 2006). Thus it is of great interest to the Chilean Copper Mining Industry, which accounts for the 6.2% of Chile's GDP in real terms (COCHILCO, 2007a), to estimate their greenhouse gas emissions and carbon mitigation costs for the following years.

This study presents an interdisciplinary methodology that unifies mining, electric and environmental aspects in order to present an estimation of the carbon emissions attributed to the electricity consumption of the copper mines connected to North of Chile's electric grid *SING*. Costs of reducing these carbon emissions are also estimated considering different modifications of the electric grid. The timeframe of this analysis is between the years 2000 and 2012.

Projections of carbon emissions in developing countries for the electric grid, and the impact of different energy sources in those emissions are topics that have been addressed in studies by Mahlia (2002) for Malaysia; Limmeechokchai and Suksuntornsiri (2007) in Thailand; Denafas *et al* (2004) for the Baltic States; and Manizini, Islas and Martínez (2001) for Mexico. Mitigation costs of the carbon emissions have been estimated for Sweden's petroleum industry by Holgrem and Sternhufvud (2008), and for Sweden's iron ore-bases steel making industry by Ribbenhed, Thorén, and Sternhufvud (2008).

1.1. Mining Industry in the Climate Change Context

According to the fifth report of the Carbon Disclosure Project (2007) —where 315 of the FT-500 companies with a combined assets value of US$41 trillion were interviewed about the risks and opportunities of the Climate Change—the Mining Industry is a carbon intense industry. It shows that, combined, the Mining, Metal and Steel Industry account for 12% of the total reported emissions. This report states that currently, the main trend in the Mining Industry is the search for cleaner, less carbon-intensive, and more efficient technologies, that can also become new business opportunities to the Industry.

1.2. Chilean Copper Mining Industry and Greenhouse Gas Emissions

Chile emitted 70.5 Mt of CO_2 by the year 2000, accounting for 0.23% of world total carbon emissions in that year (World Resources Institute, 2007). Carbon emissions by sector are shown in Figure I-1.

The carbon emissions of the Copper Mining Industry in 2000 were 8.58[1] Mt (COCHILCO, 2007c), contributing 12.2% of Chile's carbon emissions in 2000. The 30.5% of the Copper Mining Industry's emissions were produced by the burning of fossil fuels at the mines and, according to the Greenhouse Gas Protocol (World Resources Institute & World Council for Sustainable Development, 2004) are considered to be *Scope 1* emissions because they occur in the companies facilities. They account for 15.6% of the emissions in the *Manufacturing & Construction Sector* shown in Figure I-1.

[1] Only Scope 1 & Scope 2 emissions considered

On the other hand, 69.5% of the emissions of the Copper Mining Industry reported by COCHILCO are produced by the burning of fossil fuels at the power plants that generate the electricity consumed by the mines. This means that 37.8% of the emissions of Chile's *Electricity & Heat Sector* shown in Figure I-1 came from the Copper Mining Industry. These types of indirect emissions are called *Scope 2* emissions, and are the types of emissions that will be addressed in this study.

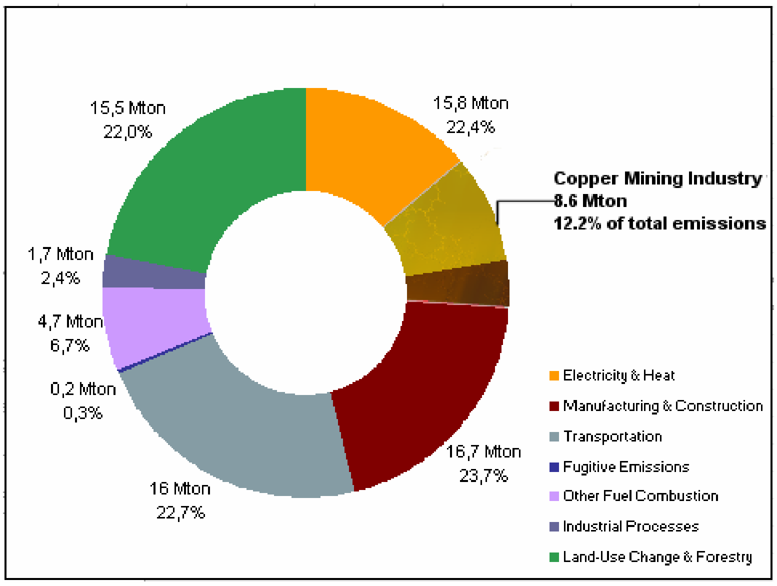

Figure I-1: Carbon emissions in Chile in 2000, by Sector (World Resources Institute, 2007; COCHILCO, 2007c)

1.3. Importance of North of Chile's Electric Grid

Northern Chile's electric grid —*SING*— is the second largest electric grid in Chile, producing 24.5% of the electricity generated in 2006 with an installed capacity of about 3596 MW (CDEC SING, 2007b). Electricity generation in this system is almost entirely thermal, due to the absence of mayor hydroelectric resources in the North of Chile.

The carbon emissions estimation for the SING is relevant to the Copper Mining Industry because the copper mines connected to this system produce approximately 72% of the total of fine copper produced in Chile (COCHILCO, 2007a). The copper mines connected to the SING are shown in Table I-1.

Table I-1: Copper mines connected to the SING*.

Mine	**Type of Product**
Altonorte	Blister
Cerro Colorado	SX-EW Cathodes
Cerro Dominador	Concentrates, SX-EW Cathodes
Codelco Norte	Concentrates, SX-EW Cathodes, Blister, ER Cathodes
Collahuasi	Concentrates, SX-EW Cathodes
El Abra	SX-EW Cathodes
El Tesoro	SX-EW Cathodes
Escondida	Concentrates, SX-EW Cathodes
Esperanza	Concentrate
Gaby	SX-EW Cathodes
Ivan/El Zar	SX-EW Cathodes
La Cascada	SX-EW Cathodes
Lomas Bayas	SX-EW Cathodes
Mantos Blancos	Concentrates, SX-EW Cathodes
Mantos de la Luna	SX-EW Cathodes
Michilla/Lince	SX-EW Cathodes
Quebrada Blanca	SX-EW Cathodes
Sierra Gorda	SX-EW Cathodes
Spence	SX-EW Cathodes
Zaldivar	Concentrates, SX-EW Cathodes

*SX-EW: solvent extraction and electrowinning; ER: electrorefined.

At the time of this study, the SING was undergoing a lot of changes in its operation because of the natural gas crisis that started in 2004, which was caused by the reduction of Argentina's natural gas (CNE, 2007b). This situation and its effects on carbon emissions are discussed in the analysis.

1.4. Mitigation of Greenhouse Gas Emissions

The IPCC estimates future global carbon emissions and their reduction potential within a wide set of scenarios. This represents the uncertainties involved in such a complex task (IPCC, 2007). As an example of the reducing potential of different actions that can be taken to mitigate carbon emissions, an estimation for one of the scenarios is shown in the following Figure:

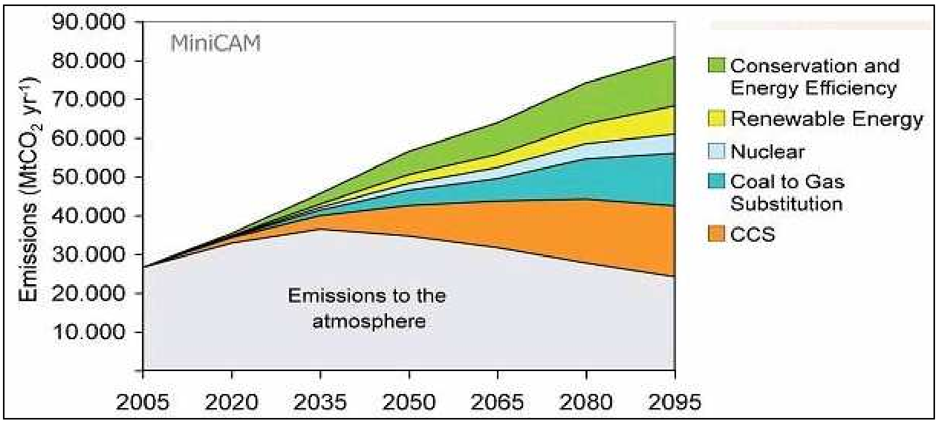

Figure I-2: Projected carbon emissions and mitigation potentials for the SRES B2 Scenario, by the MiniCAM Model (IPCC, 2007).

In this study, carbon emissions reduction costs were calculated for some of the mitigation actions shown in Figure I-2. These actions are:

(a) *Renewable Energy*. The energy sources included are geothermal, wind power, and solar photovoltaic.

b) *Conservation and Energy Efficiency*. The technologies of the coal/petcoke fired power plants that are projected to be built in the SING in the following years were compared with more advanced technologies on coal-fired power plants, in terms of costs and carbon emissions.

c) *Coal to Gas Substitution*. Carbon reduction costs were estimated for changes in the operation of the SING by the year 2012, when LNG is expected to be fully available in the electric grid. But according to the developed model these will not be required because of the cheaper generation of coal and petcoke.

Carbon reduction costs for Carbon Capture and Storage (CCS) were not estimated in this study because, according to many authors, its deployment is expected to begin in the following decades, when carbon emissions become more constrained and the technology is fully developed (IPCC, 2007).

Nuclear Energy is not addressed in this study. Chile’s Minister of Energy Marcelo Tokman believes its implementation in Chile is not expected to occur before 2020 (Electricidad Interamericana, 2007a). This is because of the small size of the electric grid, the amount of studies required, and the acceptance of its use by the public.

II. OBJECTIVES

The general objective of this study is to present an interdisciplinary methodology that applies concepts of mining engineering, electric engineering, economics and environmental sciences, in order to provide an answer for two specific objectives:

The first specific objective is to obtain an estimation of the annual carbon emissions attributed to the electricity consumption of the Copper Mining Industry connected to the SING, for the period between 2000 and 2012.

The second specific objective is to estimate the carbon emissions reduction costs in the electric grid, considering the following alternatives:

- The planned power plants that are expected to enter the system use more advanced fossil fuel fired generation technologies. Evaluated technologies are: *combusting fluidized bed* (CFB) (both coal and petcoke fired); *pulverized coal supercritical*; and *integrated gasification combined cycle* (IGCC) (coal-fired).

- Carbon emissions are reduced by changing the fuel mix. Reduction costs were estimated with the new planned power plants using currently planned technologies, and also using the IGCC technology, which has the highest carbon reduction potential according to the results obtained.

- The inclusion of renewable energy sources into the grid. Evaluated technologies are: *geothermal*, *wind power* and *solar photovoltaic* (PV).

III. ESTIMATION OF CARBON EMISSIONS BETWEEN 2000 AND 2012

3.1. Methodology overview

The annual carbon emissions of North of Chile's electric grid, SING, were estimated with an emission model that uses the amount of fossil fuels burned for electricity generation. This required an estimation of the electricity demand for the analyzed period, and a model of the system's behavior that included detailed information on the available—and projected—power plants of the electric grid. Since the Copper Mining Industry accounts for around 80% of the *SING*'s electricity demand (COCHILCO, 2007c), it was necessary to model the electricity consumption of a copper mine, allowing the estimation of the electricity demand of the Industry to be based upon the available annual production estimation (which was available from consultant's estimations).

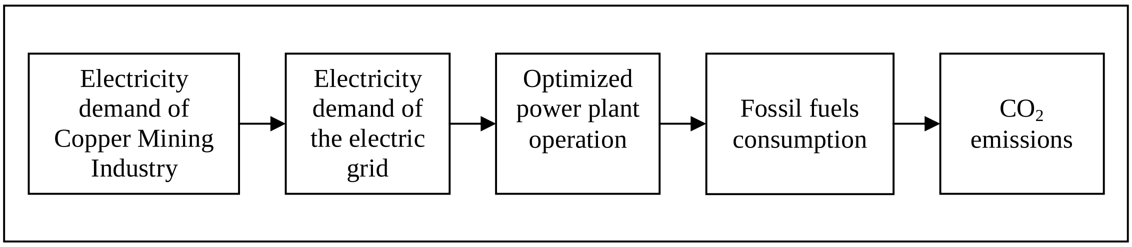

Figure III-1: Methodology overview for carbon emissions estimation.

3.2. Electricity Demand of the Copper Mining Industry

Among the available information used in this study was the copper production of the mines connected to the SING from 2000 until 2006, and in addition, an estimation of their production until 2012 (González, 2007). These values are shown in Table A-1 in the Annex A.

The methodology used to estimate the electricity consumption of the copper mines is based on *unitary electricity consumption coefficients* for the different processes of an average copper mine connected to the SING (COCHILCO, 2007b). These are measured in units of energy per mass of fine copper, and represent the energy intensity for each of the processes of the mine. Unitary electricity consumption coefficients were estimated by COCHILCO from the year 2000 until 2006 and are shown in the following Table:.

Table III-1: Unitary electricity consumption coefficients for the SING, in mega joules per ton of fine copper (COCHILCO, 2007b).

Process	Units[2]	2000	2001	2002	2003	2004	2005	2006
Extraction -Open pit mine	MJ/MTF in mineral	474.9	465.9	504.4	569.9	604.0	685.4	651.2
Extraction - Underground mine (average national)	MJ/ MTF in mineral	1195.2	1248.3	1337.3	1394.5	1257.9	1535.1	1678.7
Concentration	MJ/ MTF in concentrates	4655.0	5082.9	5570.2	6250.2	5755.2	6071.7	6095.5
Smelting	MJ/ MTF in anode	3650.5	3664.2	3814.1	3935.2	4229.0	4237.0	4342.0
Refining	MJ/ MTF in cathodes	1131.4	1143.6	1130.2	1132.2	1155.0	1207.8	1133.9
LX/SX/EW	MJ/ MTF in cathodes	10141.1	9557.9	9853.2	10107.3	10294.3	9847.1	9887.1
Services	MJ/ MTF in product	459.9	496.4	446.7	367.6	367.3	494.2	417.0

The unitary electricity consumption coefficients of some of the processes have had important variations in the last years. Concentration process increased its unitary electricity consumption 31% between 2000 and 2006, mainly because of the mineral's higher hardness (S. Pimentel, personal communication, November 19, 2007), which makes the ore harder to crush and therefore the process becomes more energy-consuming. Mineral hardness in three mines accounting for the 24% of Chile's annual copper production risen an average of 6% between 2001-2006 (G. Lagos, personal communication, January 4, 2008).

The unitary electricity consumption coefficient for the Extraction process in open pit mines increased 37% between 2000 and 2006. This variation can be attributed to two different factors: longer transportation distances for the mineral, where electricity-powered conveyor belts are used (S. Pimentel, personal communication, November 19, 2007); and diminishing ore grades in many copper mines, as ore grade has decreased a weighted average of 12% in a group of mines that account for the 66% of Chile's annual copper production (G. Lagos, personal communication, January 4, 2008). Variations on the electricity consumption of the Extraction process in underground mines was not further analyzed as this type of mine accounts for less than 1% of the total copper production in the SING.

Smelting increased its unitary electricity consumption 19% between 2000 and 2006. This can be attributed to the higher sulphuric acid production (G. Lagos, personal communication, January 4, 2008), as sulphuric acid production in the Tarapaca Region and Antofagasta Region (both powered by the SING) raised 45% between 2000 and 2006 (COCHILCO, 2007a).

A linear trend assumption was made for the unitary coefficients for the period 2007-2012. Thus a linear regression was made for each of the coefficients with the data between 2000 and 2006, and the future coefficients were estimated using the resulting model.

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[2] Metric tons of fine is shortened as "MTF"

The annual electricity consumption of a mine was calculated as the sum of the electricity consumption of the different processes that the mine has. Using these unitary coefficients, the electricity demand of a mine with *n* processes for year *k* can be estimated as:

$$E_k = \sum_{i=1}^{n} UC_{i,k} \times P_{i,k} \tag{1}$$

Where $UC_{i,k}$ is the unitary electricity consumption coefficient of the process *i* in year *k*, in kWh/ton of fine copper; $P_{i,k}$ is the mass of fine copper (in metric tons) that comes as an output for the process *i* in year *k*; and $E_{j,k}$ is the electricity demand of mine *j* in year *k*. The coefficients used for a given mine varied depending on the mine type (open pit or underground) and the product type (concentrate, cathodes, anions and/or electrolytic).

As shown in Table III-1, unitary consumption coefficients of Concentration and LX/SX/EW processes are expressed in terms of tons of fine copper in mineral and not in terms of the final product. The reason for this is that there are losses of fine copper in the Concentration and LX/SX/EW processes. In order to use these coefficients in Equation 1 *recovery factors* need to be used to transform the mass of fine copper contained in mineral into mass of fine copper contained in the final product. This can be performed with the following Equation:

$$P_i = PM_i \times R_i \tag{2}$$

Where P_i is the annual mass of fine copper contained in the mine's final product (in metric tons) that comes as an output for the process *i*; PM_i is the annual mass of fine copper contained in the mineral (in metric tons) that comes as an output for the process *i*; and R_i is the recovery factor of the process *i*. Concentration process in the SING had an average recovery factor of 86.4% between 2000 and

2006, and the average recovery factor for the LX/SX/EW process in the SING was 75.6% during this period (S. Pimentel, personal communication, September 14, 2007).

The annual electricity demand of the whole Copper Mining Industry was estimated as the sum of the demand of all the mines, smelters and a refinery:

$$DEc_k = \sum_{j=1}^{m}\sum_{i=1}^{n} UC_{i,k} \times P_{j,i,k} \tag{3}$$

Where DEc_k is the total electricity demand of the Copper Mining Industry in the year k; $UC_{i,k}$ is the unitary electricity consumption coefficient of the process i in year k, in kWh/ton of fine copper (the same value for every mine); $P_{j,i,k}$ is the mass of fine copper of mine j, contained in the mine's final product (in metric tons) that comes as an output for the process i in year k. The estimation resulting for the electricity demand of the Copper Mining Industry connected to the SING is shown in the Figure III-2.

3.3. Estimation of the Electricity Demand of the SING

The SING has two types of clients: *regulated clients* and *free clients*. The clients who pay a fixed price set by the authority on a regular basis (*regulated clients*), are mostly companies that supply the electricity to the general public. On the other hand, there are the clients who negotiate their price directly with the electricity generating companies through a private contract (*free clients*). Free clients predominately include mines and accounted for the 90% of the demand between the year 2000 and 2006 (CNE, 2007a).

Annual electricity demand in the SING was estimated as:

$$DE_k = DEr_k + DEf_k \tag{4}$$

Where DE_k is the total electricity demand in the SING in the year k; DEr_k is the electricity demand of the regulated clients in the year k; and DEf_k is the electricity demand of the free clients in the year k.

It was assumed that the annual electricity demand of regulated clients would continue to grow with the same average rate observed in the period 2000-2006, which was 5.8% (CNE, 2007a). The resulting estimation of the annual electricity demand for this type of client can be seen in the Annex A.2.

The copper mines were separated from the rest of the free clients, and their electricity demand was calculated with Equation 3, as explained in Section 3.2. For the rest of the free clients an annual growing rate of 22.4% was assumed, being the average between 2001 and 2006 (CNE, 2007a). The estimation of the annual electricity demand for the rest of the free clients can be seen in the Annex A.3. Thus annual electricity demand of the regulated clients was calculated as:

$$DEr_k = DErfc_k + DEc_k \tag{5}$$

Where DEr_k is the total electricity demand of the regulated clients in the SING in the year k; and $DErfc_k$ is the electricity demand of the "rest of the free clients" in the year k; and DEc_k is the total electricity demand of the Copper Mining Industry in the year k, estimated with Equation 3.

The electricity demand of the SING for the years 2000-2012 is shown in the following Figure.

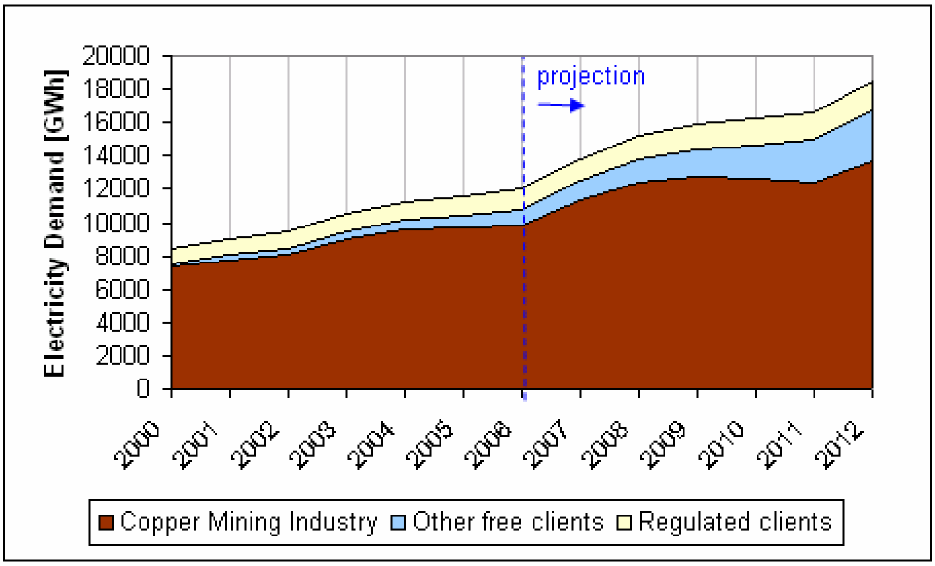


Figure III-2: Electricity demand in the SING between 2000 and 2012.

3.4. Modeling the Operation of the Electric Grid

3.4.1 Model Description

Future carbon emissions of the SING were estimated by calculating the amount of consumption of different fuels by the system, which was obtained with a model of the operation of the electric grid.

To model the operation of the SING it was necessary to understand how the Chilean electric market works. A simplification of the system's behavior is explained in the following quote:

"demand is assumed to be unresponsive to price, hence the role of the system operator is to accommodate power supply to the fixed demand. Plants are dispatched according to the merit order, i.e. they are ranked according to their marginal operating costs and dispatched in ascending order until demand is satisfied.". (Fischer *et al*, 2003, p.303-304).

Because power plants are dispatched according to their marginal cost in an ascending order, the system operator has to solve a minimization problem that leads to the least expensive way of fulfilling that demand (Fischer *et al*, 2003). For this study, a model has been implemented using Solver Premium on Microsoft Excel to solve this standard linear minimization problem for an entire year, with the use of information from all the power plants connected to the SING. The model's output is the annual electricity generation (in GWh) and annual fuel consumption (in units of mass or volume) for each power plant, which was afterwards linked to a greenhouse gasses emissions model to estimate the emissions. For a complete description of the parameters and assumptions of this model refer to Annex B.

This model is a simplification of a more complex system. Other processes such as starting up and shutting down of the power plants, or operation with minimum levels, have not been modeled, assuming that their impact on the results is low. This could have resulted in a sub-estimation of the fuel consumption in the system, as fuel consumption rates are higher when these additional process occur.

Table III-2: Data needed for the SING's operation model.

Model Input	**Intermediate estimations**	**Model Output**
Power plant data		
-Gross capacity -Net capacity -Availability factor -Fuel type -Specific fuel consumption -Non-fuel variable costs	Variable costs	Electricity generation
Fuel data		
-Fuel prices -Natural gas availability		Fuel consumption
System's information		
-Annual Electricity demand	Load duration curve	System's variable costs

The operation of the SING was modeled for each year was obtained with the optimization problem shown in Table III-3. Each year was divided in three representative ranges according to the base-load duration curve of the system (see Section 3.4.6). The solutions of this problem are the annual generation of each of the power plants of the SING, for the period between 2007 and 2012.

Table III-3. Optimization problem, solved for each operation range, for each year.

<table>
<tr><td colspan="3">Minimize $TC = \sum_{i=1}^{n}\sum_{k=1}^{m_i} VC_{k,i} \times GGen_{k,i}$</td></tr>
<tr><td>Subject to:</td><td colspan="2">(1) $\sum_{k=1}^{m_i} \frac{GGen_{k,i}}{PF_{k,i} \times FA_k} \leq MaxGGen_i$, i Є [1,n]

(2) $\sum_{i=1}^{n}\sum_{k=1}^{m_i} NGen_{k,i} = \frac{DE}{(1-DL)}$</td></tr>
<tr><td>Where:</td><td colspan="2">$NGen_{k,i} = GGen_{k,i} \times (1-OC_{k,i})$, k Є [1,m_i], i Є [1,n]

$GGen_{k,i} \geq 0$ k Є [1,m_i], i Є [1,n]</td></tr>
<tr><td>Variable names:</td><td>TC: variable costs of the operation of the SING [US$].
$VC_{k,i}$: variable cost for plant i when using fuel k, on a gross generation basis [US$/GWh].
$GGen_{k,i}$: gross generation for plant i when using fuel k [GWh].
DE: the total electricity demand of the operation range [GWh]
n: number of power plants
m_i: number of fuels with which power plant i can operate.
FA_k: fuel availability factor for fuel k</td><td>$NGen_{k,i}$: net generation for plant i when using fuel k [GWh].
$PF_{k,i}$:availability factor of plant I when using fuel k [%].
$OC_{k,i}$: own consumption of plant i when using fuel k[%]
DL: distribution losses [%]
$MaxGGen_i$: maximum gross generation for plant i [GWh]
$GGen_{k,i}$: gross generation for plant i using fuel k[GWh].</td></tr>
</table>

Constraint (1) addresses the fact that no power plant can generate more than its maximum effective generation capacity. Constraint (2) requires that the net electricity generated by the system has to be equal to the electricity demand, considering the distribution losses, which are estimated as a 4.1% (CDEC SING, 2007b). The electricity demand for each time range was calculated according to the system's base-load duration curve (Section 3.4.6).

The SING's operation model was successfully validated by obtaining results for past years (2001-2006) and comparing them with the real operation information for these years. This validation and the assumptions involved are explained in Section 3.5.

The power plants included in the SING's operation model from 2007 to 2012 are listed in Annex B.1. This information was obtained from a self-generated report from CDEC SING (2007e). The new power plants planned for the system are added to this list for the years that they operate, their technical information is available in Annex B.6. The assumptions and equations used on their modeling is described in this Section.

3.4.2 Availability factors

Power plants don't operate all the time using maximum power. This can be represented by an *availability factor*, which represents the percentage of maximum generating capacity that the plants actually generate for a certain period of time (The Royal Academy of Engineering, 2004). In this study, availability factors were calculated as:

$$PF_i=(100\% - MF_i)\times OM_i \tag{6}$$

Where PF_i is the availability factor of the power plant *i* (%); maintenance factor MF_i is the percentage of the year on which power plant *i* is in maintenance; and operation margin OM_i is the percentage of the maximum capacity on which the plant *i* normally operates because of security reasons (J. Venegas, personal communication, August 16, 2007). Availability factors for all the power plants are listed in Annex B.2.

The maintenance plan for all the power plants for the period 2007-2011 was obtained from the report *CDEC SING C-0001/2007* (CDEC SING, 2007g). In the *SING*'s operation model, the *maintenance factor* used for 2007-2012 for each power plant was the average *maintenance factor* of the plant calculated from the report for 2007-2011. *Maintenance factors* for each power plant are shown in Annex B.2.

The *operation margins* were obtained using different approaches depending on the type of power plant:

a) For coal-fired and gas-fired combined cycles the *operation margins* were obtained from a CDEC SING's employee (J. Venegas, personal communication, August 16, 2007).

b) For the two small hydroelectric power plants, margins were estimated by comparing the plants real generation for 2000-2006 with their maximum capacity.

c) For diesel and fuel oil motors, *operation margins* were estimated by comparing the *firm power* with their maximum power. This information was obtained from the report *CDEC-SING C-0009/2007* (CDEC SING, 2007h).

Availability factors were also estimated for the projected power plants that will start operating in the following years. They can be found in Annex B.6.

3.4.3 Modeling Natural Gas Availability

Natural gas availability was modeled with a *natural gas availability factor* calculated as:

$$NG = \frac{EPs}{EP} \tag{7}$$

Where *EP* is the gross annual electricity that could be generated by the gas-fired power plants in the system (in GWh) if there was no natural gas shortage; *EPs* is the gross annual electricity that can be generated by gas-fired power plants with natural gas shortage; and *NG* is the natural gas availability factor.

The natural gas availability factor was estimated for the period 2004-2007, using information from the CNE (2007b). Expected volume of gas was compared with the volume that was actually received in the period and this ratio was assumed to be equal to the natural gas availability factor, which was confirmed by the validation of the model, described in Section 3.5. Natural gas availability factors in this period are shown in Annex B.3. For 2007 an annual average value of 10% availability was assumed, based on the development of the natural gas crisis at the time of this study (Electricidad Interamericana, 2007b).

The natural gas-fired Salta Power Plant is located in Argentine territory, and began to initiate restrictions on its natural gas supply in 2007. Natural gas availability for this power plant is modeled using a different *natural gas availability factor*. For 2007, it was assumed to be at 60% according to information available from reports by the CDEC SING (2007i).

Assumptions on the natural gas availability in the system for the period 2008-2012 can be found in Section 3.7.

3.4.4 Effective Net Power

The effective net energy that a power plant can produce on a certain year (i.e. the amount of energy that a plant can produce considering maintenance, operation margins and fuel availability), was calculated with the following equation:

$$NGenc_i = PFi \times (100\%-OCi) \times FA \times GGenc_i \qquad (8)$$

Where $NGenc_i$ is the effective net annual generation capacity of the power plant i; PF_i is the availability factor of power plant i as described in Section 3.4.2; OC_i is the own power consumption of power plant i; FA_i is the fuel availability factor for power plant i, which is different from 100% only for the gas-fired power plants, as described in B.3; $GGenc_i$ is the amount of gross annual generation that power plant i could produce if it was operating the whole year at maximum power.

The individual power consumption values of the power plants on the SING were obtained from a self-generated report from CDEC SING (2007e). These values represent the percentage of the generated power that is consumed by the installations of a power plant, and they were assumed constant for all the years.

Individual power consumption values and calculated effective net generating capacities (in power units) are shown in Annex B.4.

3.4.5 Power Plant Variable Costs

The variable costs of a power plant are the costs that depend on the amount of electricity generated, and are expressed in units of US mills/kWh[3] of gross generation. They can be divided into *fuel variable costs* (FVC) and *non-fuel variable costs* (NFVC). NFVC for each power plant of the SING were obtained from a self-generated report by the CDEC SING (2007f) and are shown in Annex B.5. FVC were calculated for each power plant as:

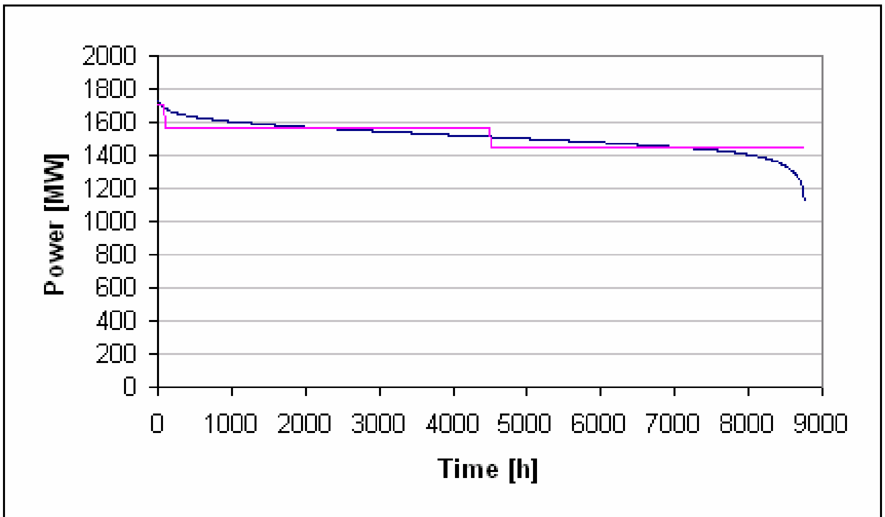
$$FVC_i = f_i \times CR_i \tag{9}$$

Where FVC_i is the fuel variable cost of the power plant i (US mills/kWh); f_i is the price of one unit of mass or volume of the fuel that power plant i uses (US\$/kg or US\$/m^3); and CR_i is the fuel consumption rate of power plant i, in units of mass or volume per unit of energy generated (kg/kWh or m^3/kWh). Fuel consumption rates were also obtained from a report by the CDEC SING (2007f) and are shown in Annex B.5. Both NFVC and fuel consumption rates values from 2006 were assumed constant for the entire evaluation timeframe. FVC on the other hand, change for each year since assumptions have been made on the future fuel prices (explained in Section 3.6).

[3] 1 mill = 1/1000 dollar

3.4.6 Base-load duration curve of the SING

Base-load duration curve of the system, i.e. the amount of time that a certain power level is generated during a year, was generated from a report by the CDEC SING (2007d) with hour-by-hour information on the system's operation for 2006. This curve, shown in Figure III-3, was divided in three representative time ranges in order to simplify the optimization model.



Range [h]	Duration [h]	Average Power [MW]	Generation [GWh]
0-100	100	1709,9	171,0
101-4500	4400	1569,4	6905,2
4501-8760	4260	1446,0	6159,8

Figure III-3: Base-load duration curve of the SING in 2006 (blue line), and simplified curve (pink line).

This curve was assumed to be representative for all the years of the analysis (H. Rudnick, personal communication, August 7, 2007). In order to use these representative ranges for the rest of the years (where the system's demand is not the same as in 2006), the electricity generation values were transformed to percentages of the annual electricity generation, and the average power values were calculated dividing the generation by the time frame. This unitary base-load duration curve values are shown in Table III-4.

Table III-4: SING's unitary base-load duration curve values and operation ranges.

Range [h]	Duration [h]	Generation [% of total annual generation]
0-100	100	1.3%
101-4500	4400	52.2%
4501-8760	4260	46.5%

3.5. Validation of the SING's Operation Model

Before using the SING's operation model to estimate future behavior of the system, a comparison was made between the resulting carbon emissions and generation by fuel type when simulating with data from 2001 to 2006, with the real carbon emissions and real generation by fuel type from those years. This was a necessary step before estimating future emissions in order to check the model's accuracy.

The power plants of the system in the period used for validation were the same as in 2007, with some exceptions in their operation:

a) Norgener Thermoelectric did not have the choice to operate with Fuel Oil in the period 2001-2006.

b) Small Diesel Zofri Power Plant that operates with diesel was not available in the years before 2007.

c) Petcoke in Mejillones Thermoelectric was not used before 2003, and it was not used in Tocopilla Thermoelectric before 2006.

d) The effects of the natural gas shortage that started in 2004 are modeled as described in B.3.

The real emissions of the system were obtained by applying the carbon emission model described in Section 3.8 into the real operation data for the power plants in the period between 2001 and 2006, which was available in self-generated reports by the CDEC SING (2007c).

Real and simulated percentages of electricity generation by fuel type are available in Annex D. Natural gas shows very similar values for both cases, including the years after 2004 when the shortage started. This tells us that the methodology used for its representation described in Section 3.4.3 is appropriate.

Coal/petcoke generation covers the rest of the cheap generation and fulfills the demand according to the simulation, having no diesel and fuel oil generation.

The reason why the model does not represent diesel and fuel oil generation so well is because they were used in this period of time as backup energy source to cover hourly peaks that are not represented in the model because of the base-load curve simplifications (Section 3.4.6). This does not prevent these sources to appear when cheaper fuels can not fulfill the entire demand. Hydropower is accurately represented; since they have no variable costs, their operation is very predictable and is not a subject of this validation.

Annex D shows a comparison between simulated and real (estimated) carbon emissions. Simulated carbon emissions are very similar to the real carbon emissions in the SING. This means that the SING's operation model is representing properly the behavior of the system in terms of carbon emissions, and thus can be used to project these emissions in the following years.

3.6. Assumptions on Fuel Prices

Average annual fuel prices in the SING for the period between 2000 and 2007 were estimated, for each fuel, as the average of the price of the fuel in the first day of every month for the years obtained from a report by the CDEC SING (2007a). These first day of the month's prices were average values among the different power plants. Fuel prices for these years are shown in Annex B.7.

For the period between 2008 and 2012, annual variations of the fuel prices in the SING were assumed to be the same as the annual variations of the projected fuel prices for the US fuel market, estimated by the U.S. Department of Energy (2007a). This assumption was considered reasonable by an expert on fossil fuels, Ph.D. Roberto Aguilera (personal communication, August 13, 2007). Petcoke prices's annual variations were not available, thus annual variations of crude price were used. Henry Hub's wellhead gas price was assumed to be equal to the LNG price. Fuel prices and annual variations in the US fuel market are shown in Annex B.7.

3.7. 2007-2012 Scenario

In the following years there are some changes expected to take place in the SING, which are summarized below.

(a) Three new coal/petcoke-fired power plants are expected to start operating between 2010 and 2012. Their technologies and capacities are summarized in Table III-5. For more detailed technical information on these power plants refer to Annex B.6.

Table III-5: Projected power plants.

Company	**Power plant**	**Technology**	**Gross Power [MW]**	**Starting year**
Norgener	Angamos	pulverized coal - sub-critical	600	2010
Suez Energy International	Andino	combusting fluidized bed	400	2010
BHP Billiton & CODELCO	Kelar	pulverized coal - sub-critical	500	2011
Empresa Nacional de Geotermia	El Tatio-La Torta	geothermal	80	2011
Empresa Nacional de Geotermia	Apacheta	geothermal	40	2012

(b) Empresa Nacional de Geotermia, an association between state-owned ENAP and ENEL, is projecting the construction of two geothermal power plants that would start operating in 2011. According to this study, they are expected to cover up 4.7% of the system's demand by 2012.

(c) The natural gas crisis previously referred to is expected to worsen until a LNG re-gasification facility (built by CODELCO and Suez energy International) begins operation in the port of Mejillones at the end of 2009. This facility is expected to increase the availability of natural gas by 450 MW (Electricidad Interamericana, 2007). The natural gas availability in the SING's power plants, expressed as a percentage of the installed natural gas generation capacity. It was assumed that in 2008 the natural gas availability factor will be 5% for Chilean territory, and 10% for the Salta Power Plant, and that in 2009 there will be no natural gas available in the SING.

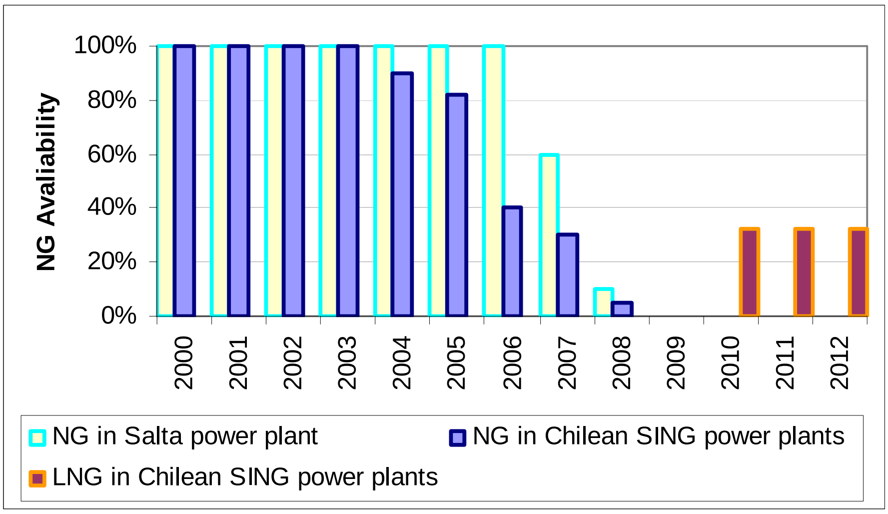


Figure III-4: Natural gas availability, in percentage of installed generating capacity of the system. (*NG: natural gas; LNG; liquefied natural gas*)

(d) The average annual fuel prices in the SING were available for the period 2000-2007 in reports by the CDEC SING (2007a). To project fuel prices in the SING for the following years, expected annual variations for the US Fuels Market estimated in DOE's *Annual Energy Outlook 2007* (U.S. Department of Energy, 2007a) were used. More details on these assumptions are available in Section 3.6, and the estimated prices are available in Annex B.7.

3.8. Emissions Estimation

According to the methodology for a *Tier 1* approach, described in *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC, 2006), the emissions of a fossil fuel-fired power plant of a certain greenhouse gas can be estimated with Equation 10:

$$E_{(G,\,F)}=FE_F\times EF_{(G,\,F)} \tag{10}$$

Where $E_{(G,\,F)}$ is the mass of the gas G emitted by the power plant in a period of time; F is the fuel type; $FE_{\boldsymbol{F}}$ is the amount of fuel F combusted in the same period of time, in energy units; and $EF_{(G,F)}$ is the emission factor of the fuel F for the gas G, in mass of greenhouse gas per unit of energy . The emission factors of the fuels are shown in Annex C.2, and because carbon emissions depend only of the fuel type and not of the combustion technology (IPCC, 2006), generic factors for the Energy Industry were used.

CH_4 and N_2O emissions were transformed to CO_2 equivalent by multiplying them by their *Global Warming Potential (GWP)*, a unit used to compare the global warming contribution of a greenhouse gas compared to the contribution of CO_2 (IPCC, 2001c).

$$E_{CO2}=E_G\times GWP_G \tag{11}$$

Where ECO_2 are carbon emissions, in mass of CO_2; EG are emissions of gas G, in units of mass of gas G; and GWP_G is the global warming potential of greenhouse G, in units of mass of CO_2 per mass of gas G. The *GWP* value for CH_4 is 23, and for N_2O is 296 (IPCC, 2001c). In this study, resulting CH_4 and N_2O emissions account for less than a 0.1% of the total carbon emissions.

The amount of fuel (in energy units) that a power plant consumes over a period of time was estimated as with the following Equation.

$$FE_F = GGen \times FC \times LHV_F \qquad (12)$$

Where *GGen* is the gross generation of the power plant, in energy units; *FC* is the *fuel consumption rate*, i.e. the amount of fuel, in mass or volume units, consumed by the power plant when generating a unit of energy; LHV_F is the low heating value of the fuel F, which is in units of energy per mass or volume. Low heating values used in this study are available in Annex C.1.

The following figures show the average carbon emission factors of the power plants of the SING. Coal/petcoke power plants clearly emit the most carbon per unit of energy generated.

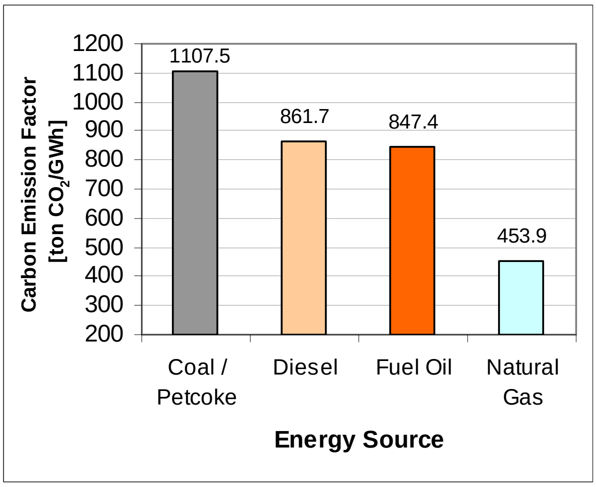


Figure III-5: Weighted average carbon emission factors of SING's power plants.

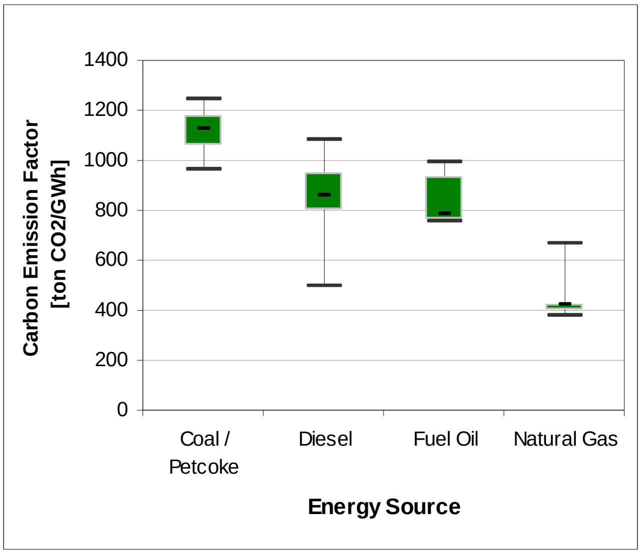


Figure III-6: Box plot of the carbon emission factors of SING's power plants.

The total greenhouse gas emissions of the whole SING for a single year can be estimated as the sum of the annual emissions of each of the power plants of the system:

$$E_{SING} = \sum_{i=1}^{n} E_i \tag{13}$$

Where E_{SING} are the annual carbon emissions of the entire SING, and E_i are the annual carbon emissions of power plant i (both in mass units).

To estimate the carbon emissions generated by the Copper Mining Industry, an emission factor for the entire SING was obtained by dividing the total carbon emissions (in tons of CO_2 equivalent) by the electricity demand of the system (in GWh). This factor represents the unitary carbon emissions of the system per unit of net energy produced, and was estimated for every year (see Figure III-9 for the resulting annual emission factor of the system). The Industry's emissions were then estimated as:

$$Ec = Dc \cdot EF_{SING} \tag{14}$$

Where *Ec* are the annual carbon emissions of the Copper Mining Industry (in tons); *Dc* is the annual electricity demand of this Industry, calculated with Equation 3 (in GWh), and EF_{SING} is the emission factor of the SING (in ton/GWh).

3.9. Results of the Operational-Environmental Model of the SING

One of the results of the operation model of the electric grid was the amount of electricity generated by each of the power plants on the system. The power plants were then grouped by energy source to obtain the generation profile by energy source of the SING, shown in Figure III-7.

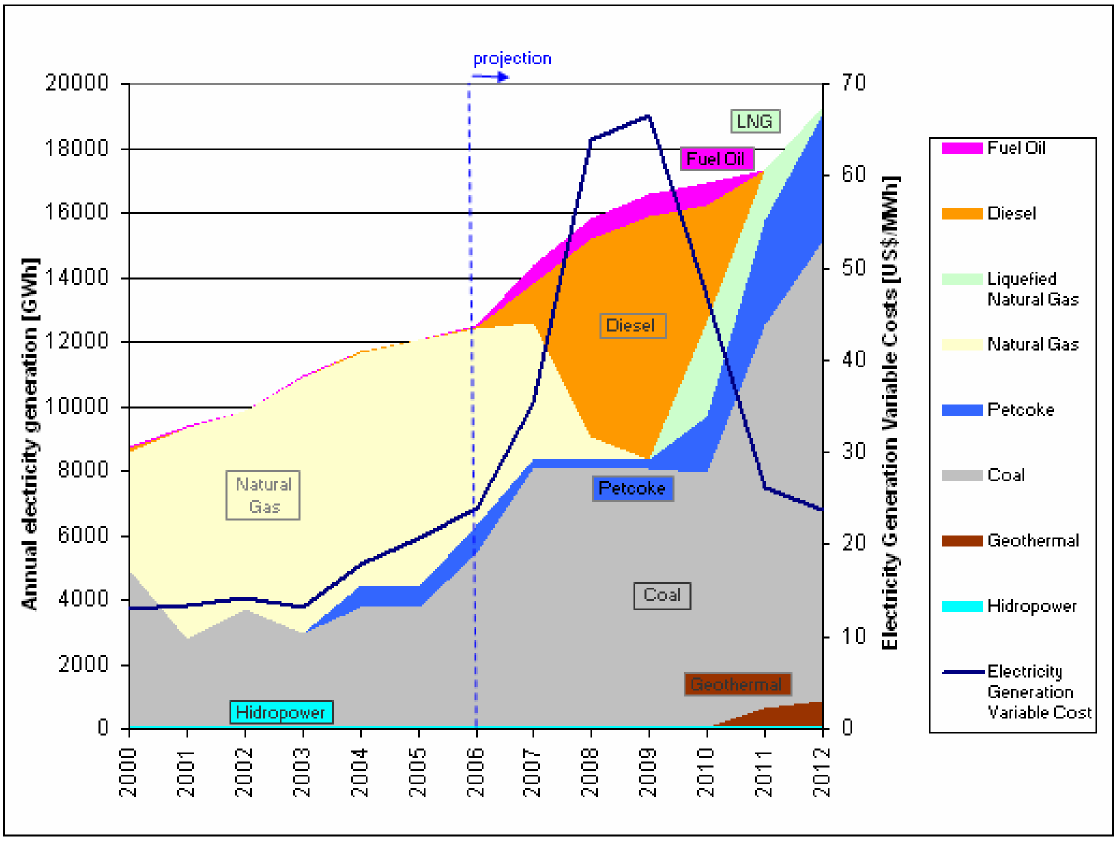


Figure III-7: Electricity generation by energy source and variable costs of the SING.

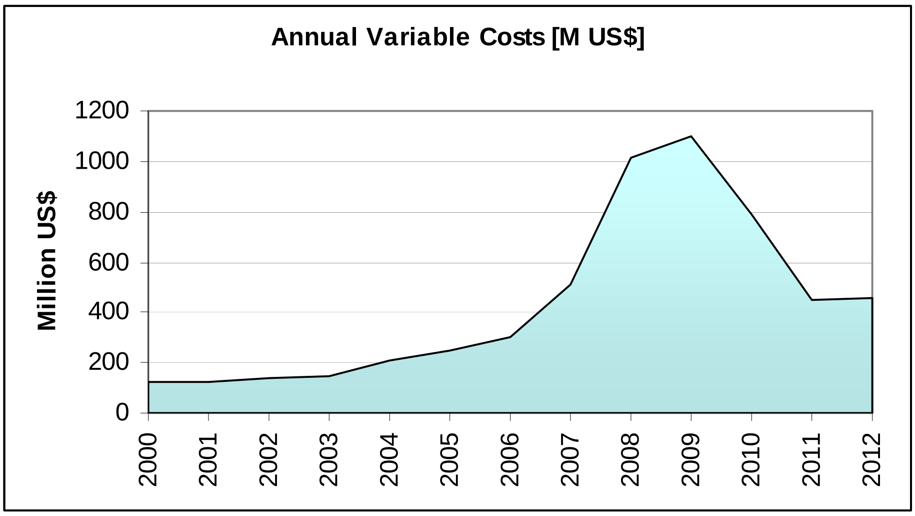


Figure III-8: Annual variable (operational) costs of the SING.

From 2000 until 2005 most of the electricity was generated with Argentine natural gas (CDEC SING, 2007b); however in 2004 the shortage started (CNE, 2007b) and coal generation increased. From 2007 to 2010, before the new planned coal/petcoke-fired power plants start their operation, combined with a shortage of natural gas, generation with diesel and fuel oil is expected to rise and account for up to 50% of the total generation by 2009. This will also increase the variable costs of the system because generation using these fuels is more expensive. After the new coal/petcoke-fired power plants start operating, coal will become the main energy source representing 74% of the total generation in 2012, and generation costs will lower.

According to these results, LNG will be used as a temporary solution when cheaper energy sources are not available, and will not be required once the new power plants are built. The reason for this is that electricity generation with LNG is expected to be more expensive than with coal or petcoke (see 3.7) , so the LNG-fired power plants will not be dispatched by the system's operator.

Geothermal energy is expected to account for 4.2% of the total generation by 2012, and by adding hydropower, renewable energies will represent 4.5% of the total generation.

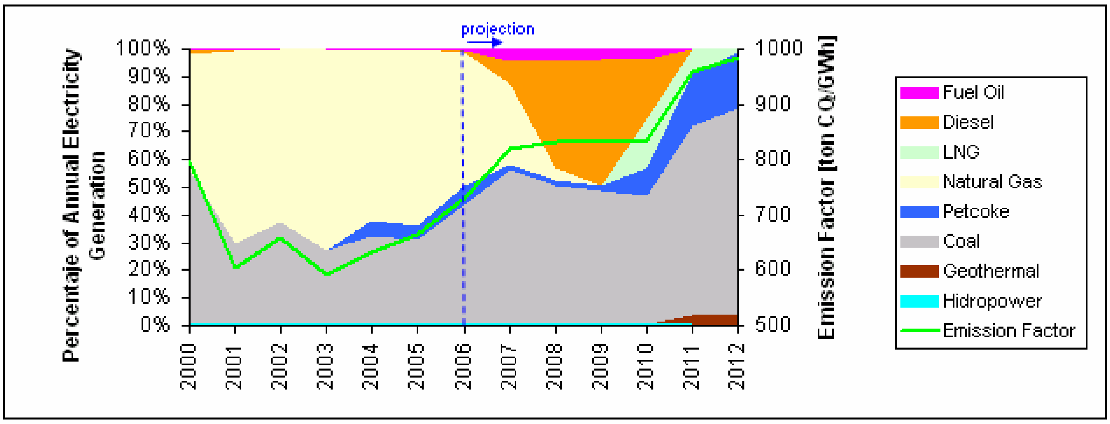


Figure III-9: Carbon Emission factor of the SING.

The emission factor of the electric grid represents the unitary carbon emissions of the system per unit of net energy generated, and can be used to compare the emission behavior of different years with different total emissions. In Figure III-9 one can see that the carbon emission factor is expected to increase after the natural gas shortage. As shown in Figure III-5, coal and petcoke generation emit around 144% more mass of carbon per unit of energy generated than generation with natural gas—the emission factor is expected to rise when the new coal/petcoke-fired power plants start their operations.

Annual carbon emissions from the SING and from the electricity consumption of the Copper Mining Industry are show in Figure III-10. The carbon emissions in 2012 are expected to be 273% of their value by the year 2000, while electricity production is expected to be 220% more than in 2000. The reason for this increase is the different fuel mix planned for 2012, which will give the system a higher carbon emission factor.

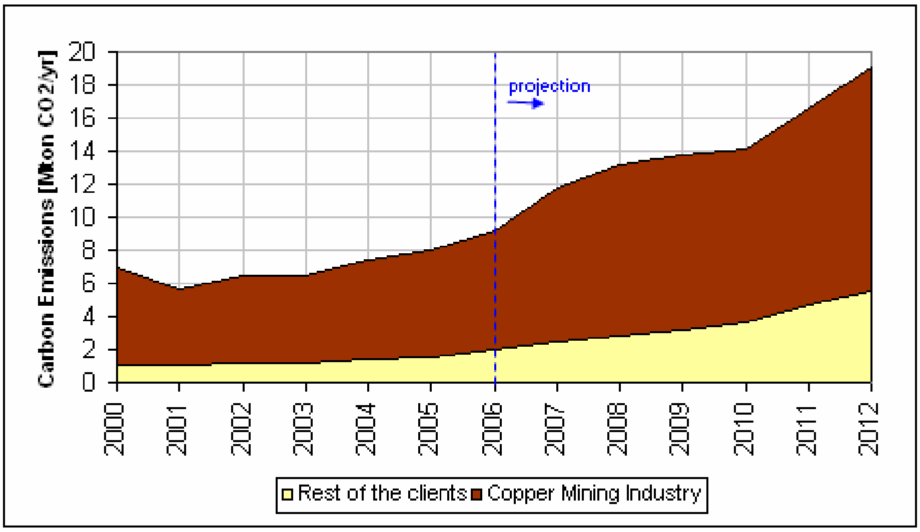


Figure III-10: Annual carbon emissions in the SING.

The relationship between the carbon emissions of the copper mines and the total emissions of the SING is the same as the relationship between the electricity consumption of both of the copper mines and the entire grid. This can be explained by the linear relationship between carbon emissions and electricity production shown in Equation 14.

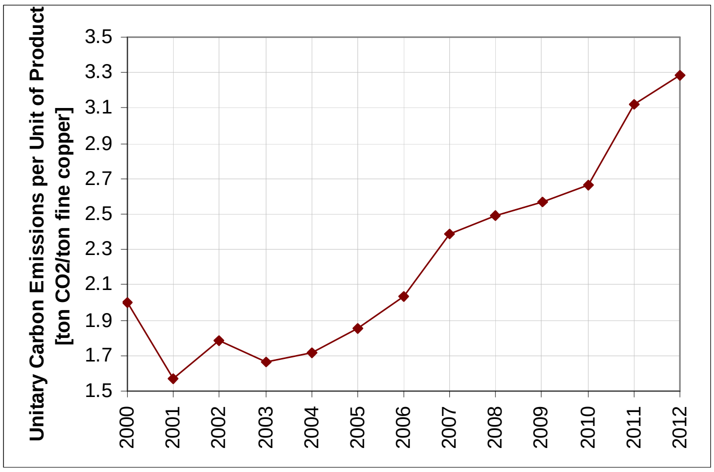


Figure III-11: Unitary carbon emissions due to electricity generation of a ton of fine copper produced in the SING.

Figure III-11 shows the unitary carbon emissions per unit of fine copper produced, due to the consumption of electricity by the Copper Mining Industry connected to the SING. The path that it follows is very similar to the one of the system's emission factor, shown in Figure III-9.

Since assumptions were made for the projections of the unitary electricity consumption coefficients of the mine processes for the period between 2007 and 2012 (shown in Table III-1), the electricity consumption and carbon emissions of the Copper Mining Industry in 2012 were also estimated for an alternative case where the unitary electricity consumption coefficients for this period are assumed to be equal to their 2006 value. A comparison of these estimations is shown in Table III-6. The difference in the Copper Mining Industry's electricity demand and in its annual carbon emissions (both for 2012) is around a 13%, while the difference in the emission factor is very low (0.7%).

Table III-6: Comparison of the electricity demand and carbon emissions of Copper Mining Industry in 2012 using two different assumptions for the future trend of the unitary electricity consumption coefficients.

	Assumption		
	linear growing (base case)	**2006 values**	**difference (%)**
Copper Mining Industry's Electricity Demand [Gwh]	13707	11982	-12.6%
Copper Mining Industry's Annual Carbon Emissions [Mton CO_2]	13.5	11.7	-13.2%
SING's Carbon Emission Factor [ton CO_2/GWh]	985.5	978.8	-0.7%

IV. CARBON EMISSIONS REDUCTION COSTS

4.1. Methodology overview

Carbon mitigation costs for the carbon emissions in the electric grid were estimated using different alternatives. These alternatives have massive carbon reduction potential from a world-wide perspective (IPCC, 2001a):

a) The introduction of renewable technologies into the electric grid. Included technologies are: geothermal flash, wind power, and solar photovoltaic (PV).

b) Implementation of efficient, more advanced fossil fuel-fired power plants in the SING, viewed as the theoretical replacement of the planned power plants by more advanced coal-fired power plants. The generation technologies evaluated are: combusting fluidized bed (CFB) (both coal and petcoke fired), pulverized coal (PC) supercritical, and coal-fired integrated gasification combined cycle (IGCC).

c) Reduction of emissions by changing the fuel mix. This was achieved by constraining the carbon emissions in the system when performing the SING's operation simulation. This alternative was evaluated for both the SING's expected base case in 2012, and for a theoretical case where the PC technology of the planned power plants is replaced by the IGCC technology (which has the highest reduction potential according to the results obtained).

For all of the alternatives, carbon emissions reduction costs were estimated using 2012 as the base year. The energy profile of that year is expected to be maintained in the SING as the energy demand will be well covered with the planned power plants (installed generating capacity is expected to overcome the demand in 49% by 2012).

The methodology used for the three alternatives is very similar. The first step was to characterize each technology by calculating its carbon emission factor and its *levelised cost of the electricity* (LCE), so they can be compared in an annual basis. This was not done for the alternative c), where the comparisons were done with the operating costs of the system. After that, the differences in carbon emissions were estimated for each new technology compared to a base case, and finally, the carbon mitigation costs were calculated by dividing the difference in cost, by the difference in carbon emissions (Holmgren and Sternhufvud, 2008; Ribbendhed, Thorén & Sternhufvud, 2008). Finally, a comparison was made between carbon reductions, annual costs and carbon prices associated with each of the evaluated alternatives in order to obtain an order of magnitude of the savings that could be obtained by selling the carbon reductions into the market.

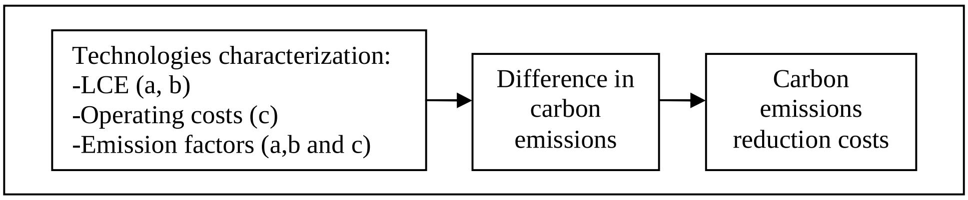


Figure IV-1: Methodology overview for carbon emissions reduction costs.

4.2. Technologies Characterization

4.2.1 Levelised Cost of Electricity

Levelised cost of electricity (LCE) is defined as an annualized, unitary cost of generating electricity (U.K. Energy Research Centre, 2007). LCE is used to compare the electricity generating costs for different technologies (International Energy Agency & Nuclear Energy Agency, 2005).

According to U.K. Energy Research Centre (2007), levelised cost of electricity (LCE) for a power plant can be estimated as:

$$LCE = \frac{AC}{NGen} \tag{15}$$

Where *LCE* is the levelised cost of electricity (US$ per kWh); *NGen* in the net generation of the power plant in a year (kWh); and *AC* are the annualized costs of the power plant (in US$), including investment, fixed and variable costs. Annualized costs are calculated as:

$$AC = AI + FC + VC \tag{16}$$

Where *AI* is the annualized investment of the power plant, *FC* are the annual fixed costs, and *VC* are the annual variable costs. The annualized investment, *AI*, is calculated as:

$$AI = NGenc \times INV \times \left(\frac{r \times (1+r)^N}{(1+r) - 1} \right) \tag{17}$$

Where *INV* is the unitary investment required to build and start operating the power plant (in US$/net kW); *NGenc* is the annual net generating capacity of the power plant (kW); *N* is the lifetime of the power plant in years; and r is the discount rate. A discount rate of 10% is used in this study.

Annual fixed costs, *FC*, are calculated by multiplying the unitary fixed costs of the technology type times the annual generation of the plant.

Annual variable costs, *VC*, are calculated with Equation 18:

$$VC = \frac{8760 \times NGen \times [VC_{NF} + VC_F]}{1 - OC} \tag{18}$$

Where *OC* is the own electricity consumption rate of the power plant; VC_{NF} are the non-fuel variable costs (US$/kWh); and VC_F are the fuel variable costs (US$/kWh), calculated with Equation 9 (Section 3.4.5).

Annual net generation, *NGen*, can be estimated as:

$$NGen = NGenc \times PF \tag{19}$$

Where *PF* is the availability factor of the power plant. By combining Equations 9 with Equations 15-19, LEC can be estimated as:

$$LCE = \frac{INV \times \left[\frac{r \times (1+r)^N}{(1+r)^N - 1}\right] + FC + 8760 \times PF \times \frac{1}{1-OC} \times [VC_{NF} + f \times CR]}{8760 \times PF} \tag{20}$$

LCE were estimated for the following technologies: pulverized coal sub-critical, pulverised coal supercritical, combusting fluidized bed (CFB) for coal and petcoke, coal-fired integrated gasification combined cycle (IGCC), wind power, geothermal flash, and solar photovoltaic. The original values used in the estimation of the LCE for each technology are listed in Annex E.

In order to compare the different technologies on a common year-basis, money units were transformed to 2006 USD with the *user consumer price index* (Officer & Williamson, 2007). These values are also available in Annex E.

The prices of coal and petcoke were projected with the same methodology described in Section 3.6 until 2030 (there are no further estimations on fuel prices annual variations). LCE were calculated for 2012 as the base year, thus average expected fuel prices between 2012 and 2030 were used as f in Equation 9. These prices are available in Annex E.

Table E-2 shows the estimated LCE for the different electricity generation technologies.

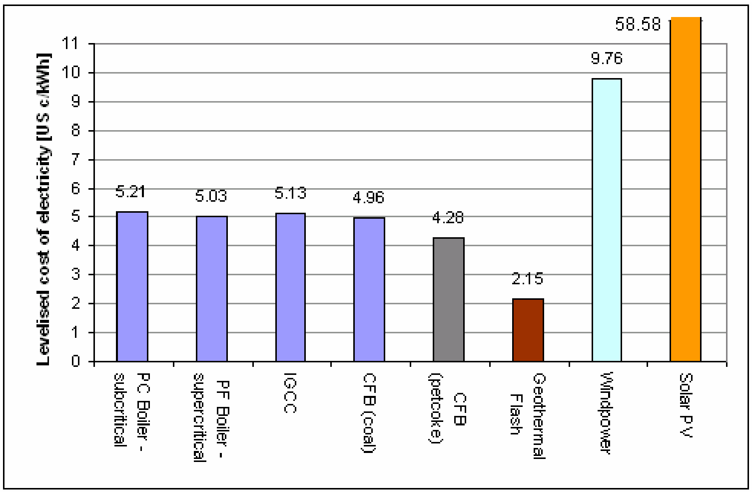


Figure IV-2: Estimated LCE for different electricity generation technologies

CFB: combusting fluidized bed; PC: pulverized coal; IGCC: integrated gasification combined cycle; LNG: liquefied natural gas; PV: photovoltaic.

4.2.2 Carbon Emission Factors

Carbon emission factors of the fossil fuel-fired power plants are shown in Figure IV-3. As described in 3.8, carbon emission factors depend on the type of fuel and on the efficiency of the power plant. The IGCC is by far the less carbon emitting technology, with an efficiency of 45.4% used in this study (US. Department of Energy,1998). Technical information of the generation technology types is available in Annex E. Renewable energies considered in this study do not emit greenhouse gases during their operations because they don't burn fossil fuels.

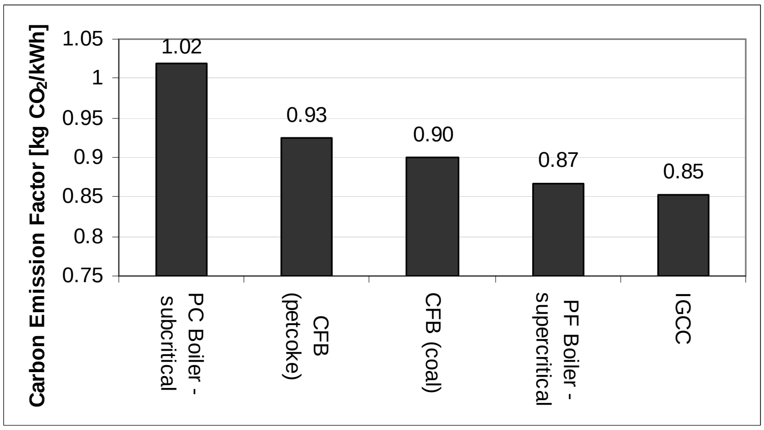


Figure IV-3: Emission factors of fossil fuel-fired power plants

CFB: combusting fluidized bed; PC: pulverized coal; IGCC: integrated gasification combined cycle.

4.3. Carbon Emissions Reduction Costs for Renewable Sources

The inclusion of renewable technologies into the grid would replace some electricity generation from the current fossil fuel-fired power plants (Keith, 2004). This means that they would also replace carbon emissions, as their emission factor is cero. The unitary carbon emissions mitigation costs for a certain installed capacity of renewable technologies were estimated with the following Equation:

$$RCost_t = \frac{LCE \times NGen_t - SAV_t}{E_0 - E_t} \tag{21}$$

Where LCE_t is the levelised cost of electricity of the renewable technology (US$/kWh); E_0 are the annual carbon emissions of the electric grid (ton/kWh) in the base case (without additional renewable technologies); E_t are the carbon emissions of the electric grid (ton/kWh) with an installed capacity t of renewable technologies; SAV_t are the system's annual savings because of the displaced fossil fuel generation; and $RCost_t$ are the unitary costs of reducing carbon in the system (US$/ton) with an installed capacity of t renewable source. *RCost* changes per every unit of renewable power that the system already has, so *RCost* is a function of the installed capacity of renewable energy and can be expressed with a curve.

The reduction costs curves were obtained by calculating *RCost* for annual generations up to 1000 GWh for each of the considered renewable sources. This was achieved with the following procedure, every 1 GWh added into the system:

a) All the power plants were listed according to their variable costs in a descending order. A renewable energy source that enters the system is expected to replace the generation of the most expensive power plants according to the SING's operating scheme of minimizing variable costs in the system.

b) For a certain installed capacity of renewable energy, the carbon emission factor of the SING (as described in Section 3.8).

c) Carbon emissions reduction costs were estimated with Equation 21.

As shown in Annex F, carbon emission reduction curves resemble horizontal lines, thus average values were used in the analysis.

Table IV-1: Carbon emissions reduction costs for renewable sources in the base case of 2012.

Technology	Carbon emissions reduction costs [US$/ton CO_2]
Geothermal Flash	-16.4
Wind Power	79.5
Solar Photovoltaic	695.3

4.4. Carbon Emissions Reduction Costs for Advanced Fossil Fuel-Fired Power Plants

As shown in Table III-5, three new coal/petcoke power plants are expected to be built on the SING. Two of them are expected to use pulverized coal sub-critical boiler technology and one of them is expected to have combusting fluidized bed (CFB) technology. From a carbon-reduction point of view, it is interesting to compare the effects on carbon emissions by the technologies planned for the new power plants, with more advanced and cleaner fossil fuel-fired technologies such as IGCC and pulverized coal supercritical. Thus, carbon emissions reduction costs were calculated for these more advanced technologies, considering in this case “reduction” as the difference between the emissions of the planned and more advanced technologies; and “costs” as the difference between the LCE of the planned and more advanced technologies. This point of view is relevant since the energy profile of 2012 is expected to be maintained in the following years in the SING as shown in 4.1.

The unitary carbon reduction costs for the advanced technologies were estimated with the following Equation.

$$RCost = \frac{LCE_{AT} - LCE_{OT}}{EF_{OT} - EF_{AT}} \tag{22}$$

Where LCE_{AT} is the levelised cost of the electricity (in US$/kWh) of the more advanced technology and LCE_{OT} is the levelised cost of electricity of the planned technology. EF_{OT} and EF_{AT} are the carbon emission factors (ton/kWh) of the planned and more advanced technology respectively (for more information on emission factors refer to Section 3.8). *RCost* are the unitary carbon emissions reduction costs (in US$/ton) of the technological improvement of the planned power plant. Carbon reduction costs for the evaluated alternatives are shown in Table IV-2.

4.5. Operation of the SING with Constrained Carbon Emissions

By 2012, with the new power plants operating and the LNG regasification facility installed in Mejillones, the installed generating capacity is expected to overcome the electricity demand of the SING by 49% (according to the demand estimation and assumptions made on this study). As was shown in Figure III-7, the NG-fired power plants will not be required after 2011 because the new coal/petcoke-fired power plants will fulfill most of the demand with a cheaper price. Thus, by 2012, the SING is expected to have the ability to reduce its carbon emissions by the inclusion of some generation with LNG into the system.

As shown in Figure III-5, the average emission factor of a NG-fired power plant is 41% of the one of a coal-fired power plant.

Carbon emissions reduction costs of the SING were obtained for certain emission reduction percentages of the whole system. This was achieved by inserting an additional restriction into the SING's operation model (see Section 3.4.1 for a description of the model) that constraints the total emissions of the system, and forces it to be a certain percentage of the base case. Thus, the following restriction was added to the optimization model:

$$E = E_{base} \times (1 - r) \tag{23}$$

Where E are the new carbon emissions in the time frame, in tons of carbon; E_{base} are annual carbon emissions in the time frame, without the emissions constraint, in tons of carbon; and r is the emissions reduction ratio. Results were obtained for emissions reductions up to a 32% (r=0.32), since the system can not fulfill the electricity demand for emissions constraints beyond that value.

For each emissions reduction percentage, carbon mitigation costs were calculated as:

$$RCost = \frac{TVC - TVC_{base}}{E_{base} \cdot r} \tag{24}$$

Where RCost are the unitary carbon reduction costs (US$/ton); TVC_{base} are the total annual variable costs of the SING without emissions restriction (in US$), and TVC is the total variable cost in the SING with emissions restriction (in US$). TVC is always be greater than TVC_{base}, because both are calculated when the system minimizes its variable costs but TVC has an additional restriction.

For the expected base case of the SING in 2012, this estimation was performed for carbon emission reductions up to 32%, which ended up to be the system's reduction potential (beyond that percentage the installed capacity was not able to fulfill the system's electricity demand). The resulting behavior of the system under the emissions constraints and the carbon mitigation costs are shown in Figure IV-5.

This optimization problem was also solved for an alternative scenario where the two planned power plants that are expected to use the pulverized coal technology, use the IGCC coal-fired technology, which (as shown in Table IV-2) has the highest carbon reduction potential (7.8%) if the three planned power plants were to use it. The system was not optimized for the three power plants using the IGCC because the technology replacement for the Andino power plant is more expensive in a unitary basis than changing the system's fuel mix for carbon emissions reduction. Because of this reason, the technology improvement for the Andino power plant is evaluated after the system is optimized for minimizing emissions.

When optimizing the system in this scenario, a carbon reduction of 30% was achieved by fuel mix replacement. Combining the carbon reduction due to the more efficient technology with the fuel mix changes the estimated carbon reduction potential of the 2012 SING is 37.8%.

4.6. Carbon prices

After the estimation of the costs and reductions on carbon emissions for each of the alternatives, the potential incomes from the sales of these emissions reductions under de Clean Development Mechanism (CDM) were estimated a set of carbon prices. These prices are 18, 20, and 22 US$/. Historic CER ("Certified Emission Reduction") prices are shown in the following Figure:

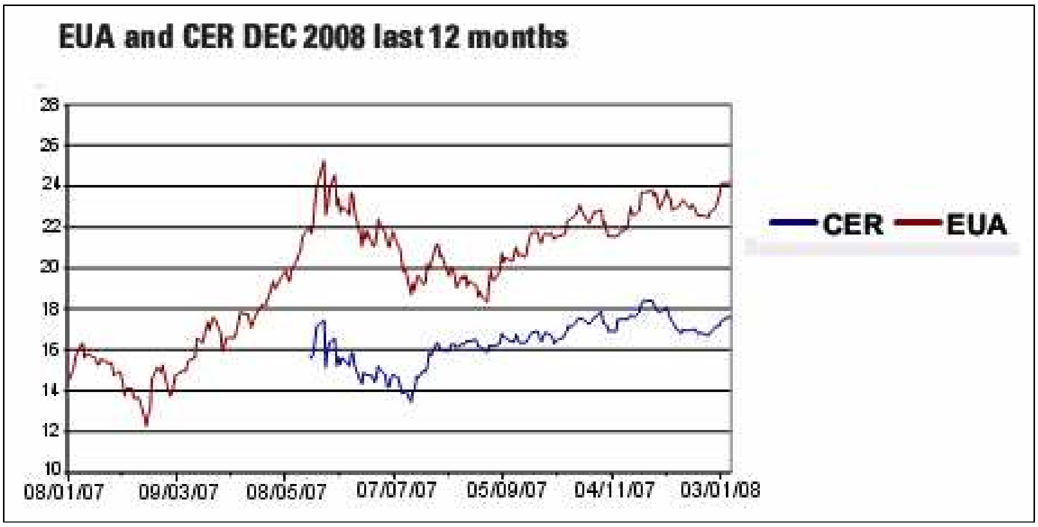


Figure IV-4: CER prices since January 2007 (Point Carbon, 2008). Prices in US$ per ton of CO_2.

4.7. Resulting Reduction Costs for Carbon Emissions

4.6.1 Comparison between Current and More Advanced Fossil Fuel Generating Technologies

Table IV-2 shows a comparison of LCE, carbon reduction potentials on the system's base emissions, and carbon reduction costs for the different evaluated alternatives. The first interesting result is the fact that replacing the planned pulverized coal sub-critical power plants by any of the other technologies has not only a carbon reduction potential because of their lower emission factors (Figure IV-3), but a cost saving potential in the electricity production, especially for the case of the CFB technology, which is planned to be used in the Andino power plant. The main reason for this is the great efficiency difference between the PC sub-critical technology and the rest, as can be seen in Annex F, which overcomes the greater investment costs for these technologies under the evaluation conditions considered (10% discount rate). For the Andino power plant the situation is different and there are no cost savings with the replacement of this technology by a more advanced one. The annual costs or savings for each of the evaluated replacements are shown in Table IV-3.

From a carbon reduction potential point of view, IGCC technology has the biggest potential with a 7.8% carbon reduction in the SING's emissions in 2012 if the three new power plants were to use this technology.

Table IV-2: Comparison between the expected technologies to be used in the SING, and alternative more advanced fossil fuel-fired technologies*.

	Currently planned technologies				
	pulverized fuel subc		CFB petcoke-fired		
Alternative technologies	additional cost of electricity [US c/kWh]	carbon emissions reduction costs [US$/ton]	additional cost of electricity [US c/kWh]	carbon emissions reduction costs [US$/ton]	Emissions reduction potential in the SING [%]
CFB (petcoke-fired)	-0.928	-98.84			3.7%
CFB (coal-fired)	-0.251	-21.04	0.677	268.5	5.1%
pulverized coal supercritical	-0.174	-11.38	0.754	128.6	7.0%
IGCC	-0.076	-4.57	0.852	116.7	7.8%

***** *CFB: combusting fluidized bed; PC: pulverized coal; IGCC: integrated gasification combined cycle.*

Table IV-3: Annual costs and savings of the replacement of currently planned power plants with more advanced technologies*.

		Power plant		
		Andino	Angamos	Kelar
Alternative technologies	CFB (petcoke-fired)		-$ 38 034 644	-$ 31 695 536
	CFB (coal-fired)	$ 20 880 344	-$ 10 272 139	-$ 8 560 116
	pulverized coal supercritical	$ 23 255 611	-$ 7 113 983	-$ 5 928 319
	IGCC	$ 26 256 508	-$ 3 123 990	-$ 2 603 325

***** *CFB: combusting fluidized bed; PC: pulverized coal; IGCC: integrated gasification combined cycle.*

4.6.2 Carbon Emissions Reduction Costs for Fuel Mix Changes

The energy source profile of the SING's base case in 2012, when imposing carbon emissions reductions into the optimization model, is shown in Figure IV-5. When reducing up to 12% of the total carbon emissions of the system, coal generation is replaced by the use of LNG until the full capacity of this fuel is used. For larger reductions, coal generation is replaced by diesel generation. When 28% of reduction is achieved, petcoke begins to be replaced by the diesel and the fuel oil. A 32% reduction is the maximum reduction that the system can achieve while fulfilling the electricity demand.

The carbon emissions reduction curve shown in Figure IV-5 has two clear trends: before, and after the LNG is up to its maximum operating capacity. For emission reductions up to 12% the carbon reduction cost stays below 23 US$/ton with an average value of $12.8 US$/ton. For greater reduction levels it grows with a higher slope up to 100 US$/ton because diesel generation is much more expensive.

According to the results of the SING's operation model shown in Section 3.9, the expected annual variable (operational) costs of the SING in 2012 is expected to be 460 million US dollar. This means substituting coal by gas at full capacity would require these annual costs to be increased on 10% (Figure IV-6). The substitution of coal by gas has much higher additional annual costs, thus it is less likely to be considered by the Industry.

If the Angamos and Kelar planned power plants are to use the IGCC technology, the resulting fuel mix for the system's operation under constrained carbon emissions is the one shown in Figure IV-7—where most of the electricity is generated by coal. The behavior of the system is similar to the one of the base case, with coal replaced by gas for up to a 12% of the reduction produced by the emissions constraint (18.6% of total emissions), and after that diesel replaces coal. IGCC power plants have a lower emission factor than the ones that use PC subcritical technology, so coal by diesel substitution occurs with a lower slope than in the base case, and the reduction costs are higher. Total carbon reduction in this case starts with 6.6% (achieved by using the IGCC technology in both the Angamos and Kelar power plants), and reaches 36.6% after optimizing the system.

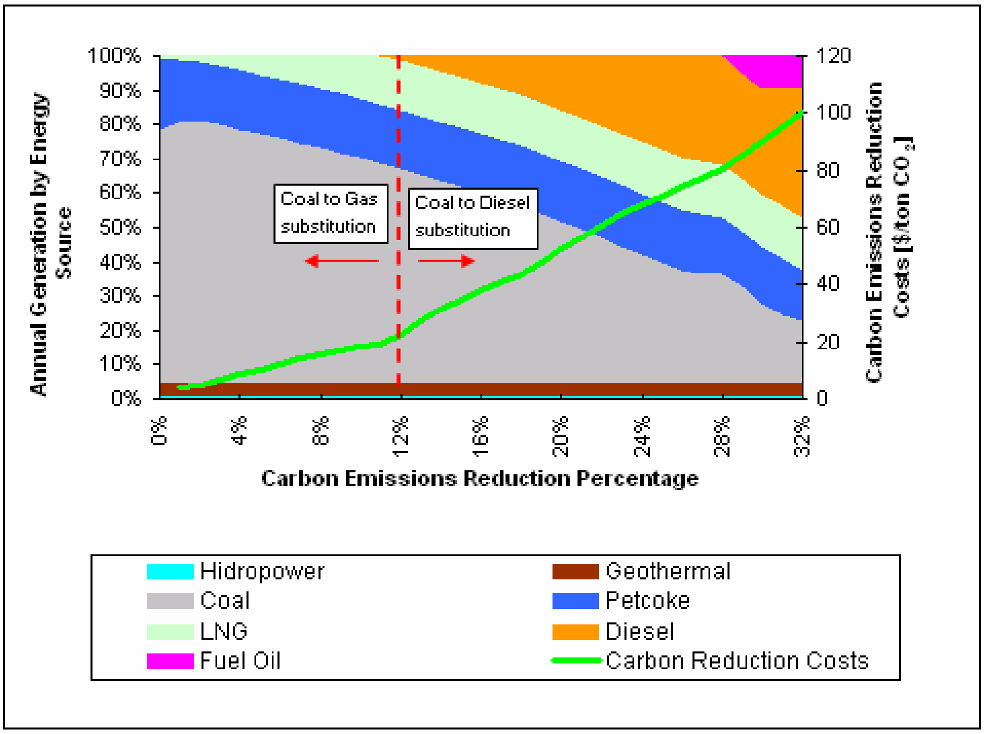


Figure IV-5: SING's operation, and carbon emission reduction costs for 2012, using currently planned technologies on the new power plants (base case).

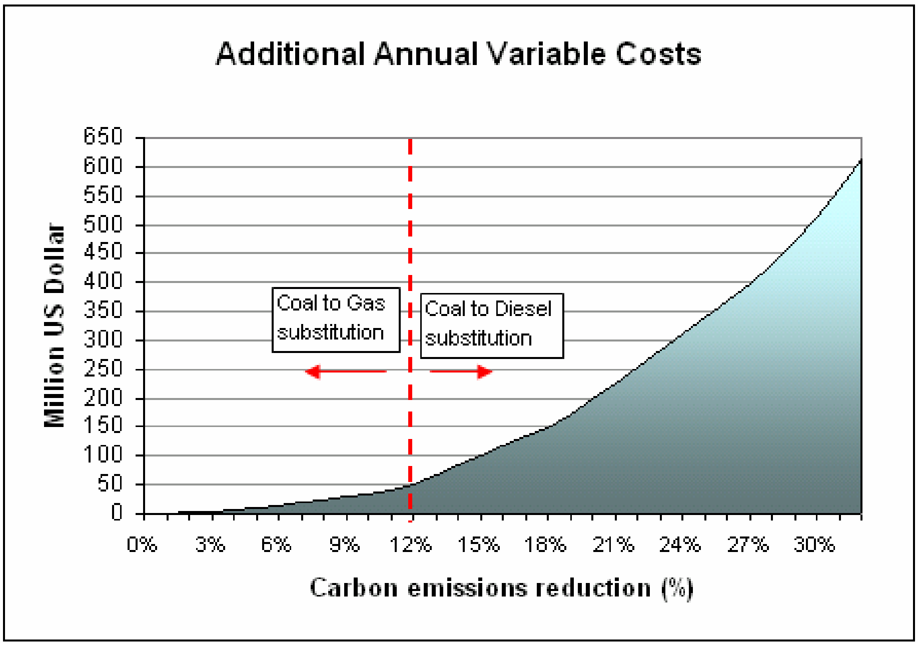


Figure IV-6: SING's additional annual variable costs when imposing carbon emissions restrictions using currently planned technologies on the new power plants (base case).

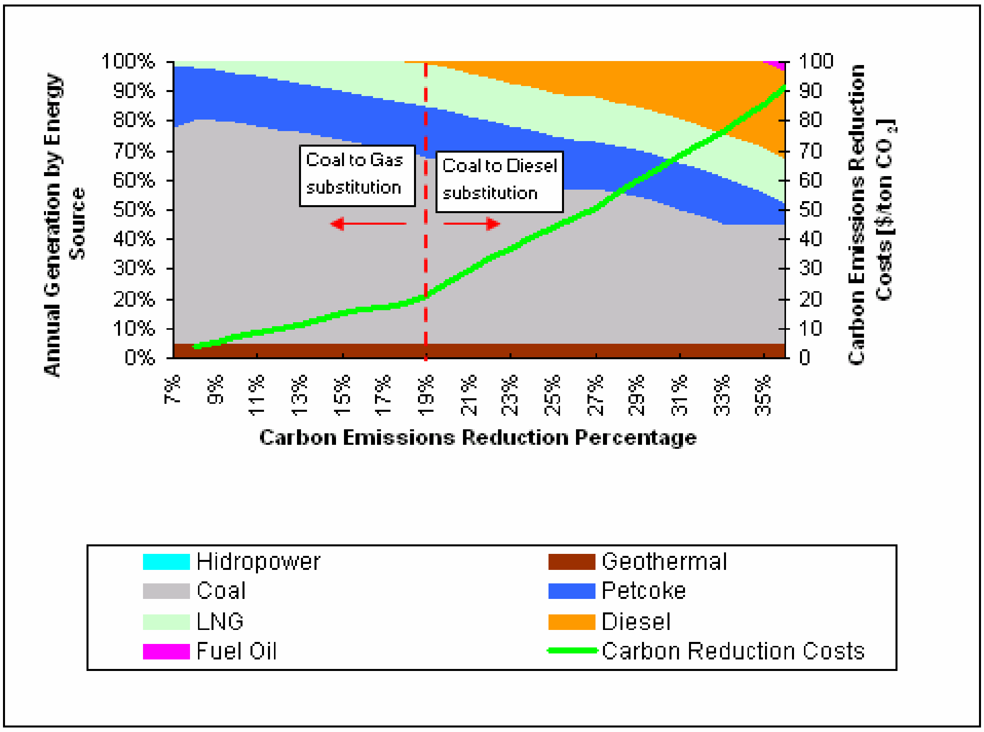


Figure IV-7: SING's operation and carbon emission reduction costs for 2012, using the integrated gasification combined cycle (IGCC) in Angamos and Kelar power plants.

4.6.3 Comparison of Unitary Carbon Emissions Reductions Costs

A summary chart of the average carbon emissions reduction costs for the system in 2012 is shown in Table IV-2. The use of more advanced fossil fuel-fired generation technologies in future power plants produces negative carbon mitigation costs as their higher efficiencies make their electricity generation cheaper than the base case that considers the use pulverized coal sub-critical technology. Among these technologies, petcoke-fired CFB accounts for the biggest negative carbon mitigation costs, even though it is the more carbon emitting option (see Figure IV-3 for the emission factors of these technologies).

Average carbon mitigation costs for substitution from coal to LNG are the lowest non-negative carbon reduction costs. Among renewable technologies, carbon emissions reduction costs for geothermal power are negative, which means that by using it the system can save money. The reason of this, is that the thermal generation displaced by the geothermal generation produces savings that are higher than the costs that this type of energy represents. The costs for solar photovoltaic are the most expensive due to their higher LCE.

Carbon emissions reduction costs are shown as mitigation curves in Figure IV-9. One can see the carbon reduction potential of each of the evaluated alternatives. Carbon reduction potential for the renewable technologies is not known because their electricity generating potential in the SING had not yet been estimated at the time of this study. Among the advanced fossil fuel burning technologies, the largest reduction potential can be achieved by the IGCC technology, with 7.8% reduction in the SING’s carbon emissions if no modifications on the system’s fuel mix are made for emissions reduction. Petcoke-fired CFB, which accounts for the lowest unitary carbon reduction costs, but has a low 3.7% reduction potential.

By combining the IGCC technology on the planned power plants, with changes in the fuel mix a 37.8% carbon emissions reduction can be achieved, but the additional annual costs of this alternative would be 540 million US$, 118% of expected annual operational costs in the system, thus this alternative is not likely to be considered by the Industry.

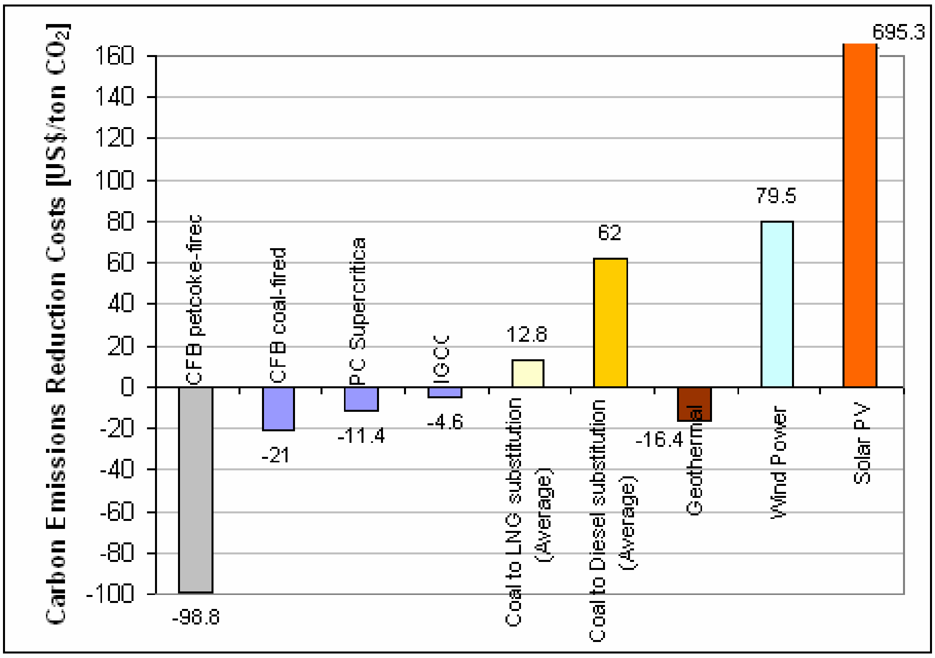


Figure IV-8: Comparison of unitary carbon mitigation costs for 2012.

CFB: combusting fluidized bed; PC: pulverized coal; IGCC: integrated gasification combined cycle; LNG: liquefied natural gas; PV: photovoltaic.

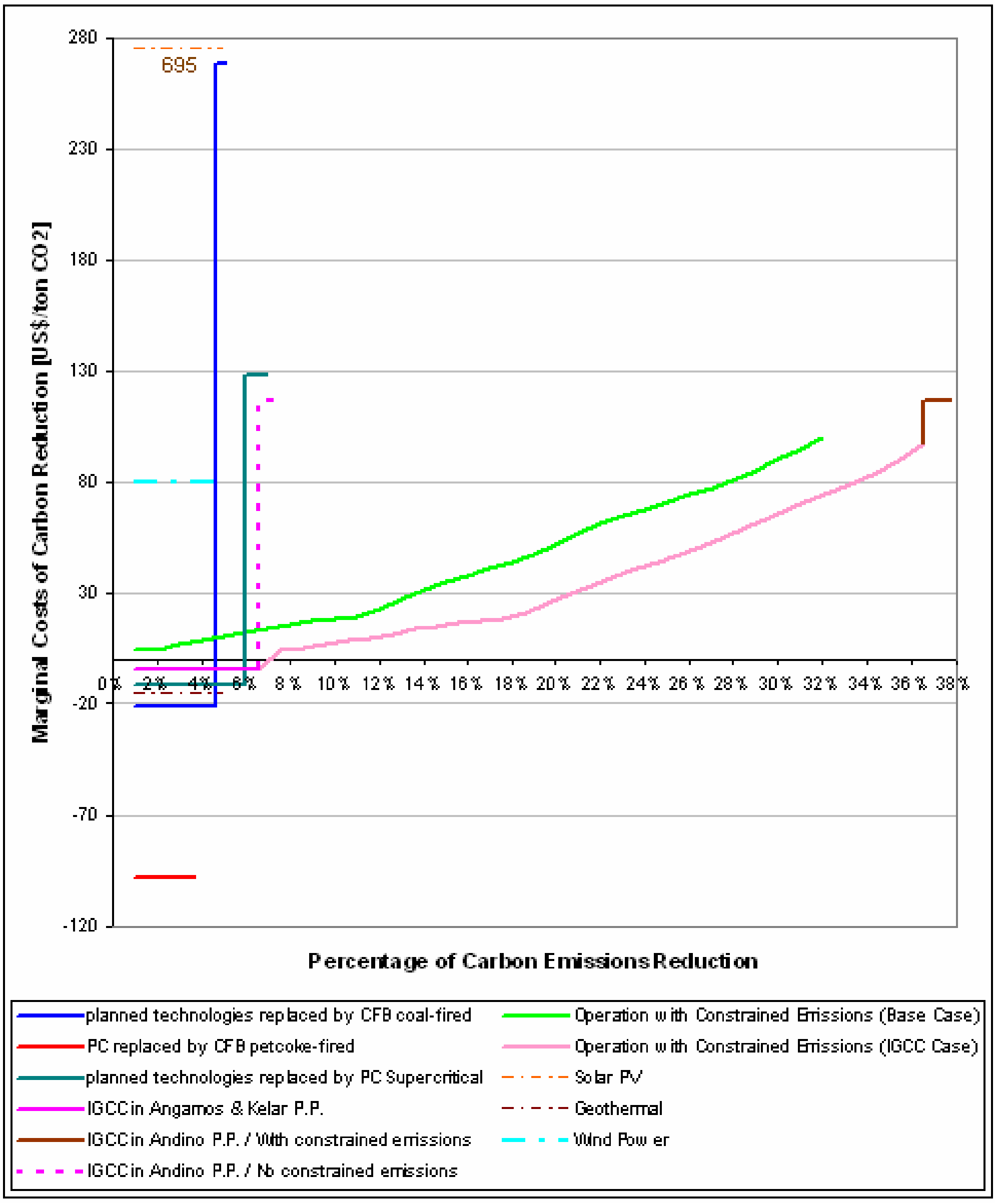


Figure IV-9: Carbon emissions mitigation curves for 2012.

CFB: combusting fluidized bed; PC: pulverized coal; IGCC: integrated gasification combined cycle; PV: photovoltaic.

4.6.4 Comparison of Total Carbon Emissions Reductions Costs

Table IV-4: Annual costs and savings of the replacement of currently planned power plants with more advanced technologies

Alternatives for Emissions Reduction	Affected Power Plants	Annual Emissions Reduction [Mton]	Annual Emissions Reduction Percentage in the SING [%]	Annual Emissions Reduction Percentage in Chile [%]	Annual Costs [Million US$]	Unitary Carbon Reduction Costs [US$/ton]
Coal to Gas Substitution	All the system	1.14	6%	0.8%	14.0	12.3
Coal to Gas Substitution	All the system	2.28	12%	1.6%	51.1	22.4
Coal to Gas & Diesel Substitution	All the system	6.09	32%	4.2%	611.5	100.4
CFB (petcoke-fired)	Angamos & Kelar	0.70	3.7%	0.5%	-69.7	-99.1
CFB (coal-fired)	Angamos & Kelar	0.90	4.7%	0.6%	-18.8	-21.0
CFB (coal-fired)	Andino, Angamos & Kelar	0.97	5.1%	0.7%	2.0	2.1
PC supercritical	Angamos & Kelar	1.15	6%	0.8%	-13.0	-11.4
PC supercritical	Andino, Angamos & Kelar	1.33	7%	0.9%	10.2	7.7
IGCC	Angamos & Kelar	1.25	6.6%	0.9%	-5.7	-4.6
IGCC	Andino, Angamos & Kelar	1.48	7.8%	1.0%	20.5	13.8
IGCC and Coal to Gas Substitution	All the system (Angamos & Kelar use IGCC tech.)	3.54	18.6%	2.4%	45.3	12.8
IGCC and Coal to Gas & Diesel Substitution	All the system (Andino, Angamos & Kelar use IGCC tech.)	7.19	37.8%	4.9%	541.1	75.2

CFB: combusting fluidized bed; PC: pulverized coal; IGCC: integrated gasification combined cycle

Table IV-4 shows annual carbon emissions reductions and costs associated with each of the evaluated alternatives. If the ratio between carbon emissions in the SING and total Chile's emissions in 2000 is assumed to be the same as in 2012 (9.9%), a gross estimation of Chile's emissions in this year can be obtained, which is 192.7 Mtons of carbon per year. Thus, carbon reduction percentages are also presented in terms of Chile's expected annual emissions.

As explained in the previous section, the use of more advanced fossil fuel generation technologies can produce savings in the system with reductions of up to 1% of Chile's estimated carbon emissions 2012. These savings were estimated to be near 70 million US$ a year if petcoke-fired CFB is used, with 0.4% carbon reduction potential in Chile's emissions; and between 5-13 million US$ a year if PC supercritical or IGCC technologies were to be used, with near 1% reduction potential on Chile's emissions.

Coal to gas substitution, which can be achieved by keep using the LNG facilities to be built in Mejillones, can achieve up to 1.6% of reduction in Chile's carbon emissions, with a marginal cost that varies depending on the reduction level with an average of 12.8 US$ per ton of carbon reduced and a top of 22.4 US$.

4.6.5 Potential Carbon Reduction Income

Potential annual income if carbon reductions are sell as CER shown in Table IV-5, for different carbon price values and for each of the evaluated alternatives. One interesting result is that the upgrading of the three new power plants into advanced coal-fired technologies gets annual incomes higher than the costs for the CER prices considered, thus it could become a business opportunity to the companies in the SING. Something similar happens to the coal to gas substitution, where the annual costs are dramatically lowered if the carbon reductions are sold.

Table IV-5: Annual carbon income and net costs when selling carbon reductions under the CDM.

Emissions Reduction Alternative	Affected Power Plants	Emissions Reduction [Mton]	Annual Costs [Million US$]	carbon price 18 US$/ton		carbon price 20 US$/ton		carbon price 22 US$/ton	
				Annual Carbon Income [Million US$]	Annual Net Costs [Million US$]	Annual Carbon Income [Million US$]	Annual Net Costs [Million US$]	Annual Carbon Income [Million US$]	Annual Net Costs [Million US$]
Coal to Gas Substitution	All the system	1.14	14.0	20.5	-6.5	22.8	-8.8	25.1	-11.1
Coal to Gas Substitution	All the system	2.28	51.1	41.1	10.0	45.7	5.4	50.2	0.8
CFB (petcoke-fired)	Angamos & Kelar	0.70	-69.7	12.7	-82.4	14.1	-83.8	15.5	-85.2
CFB (coal-fired)	Angamos & Kelar	0.90	-18.8	16.1	-34.9	17.9	-36.7	19.7	-38.5
CFB (coal-fired)	Andino, Angamos & Kelar	0.97	2.0	17.5	-15.4	19.4	-17.4	21.3	-19.3
PC supercritical	Angamos & Kelar	1.15	-13.0	20.6	-33.7	22.9	-36.0	25.2	-38.3
PC supercritical	Andino, Angamos & Kelar	1.33	10.2	24.0	-13.8	26.6	-16.4	29.3	-19.1
IGCC	Angamos & Kelar	1.25	-5.7	22.6	-28.3	25.1	-30.8	27.6	-33.3
IGCC	Andino, Angamos & Kelar	1.48	20.5	26.7	-6.2	29.7	-9.2	32.6	-12.1
IGCC and Coal to Gas Substitution	All the system (Angamos & Kelar use IGCC tech.)	3.54	45.3	63.7	-18.4	70.8	-25.4	77.9	-32.5

CDM: Clean Development Mechanism.

4.6.6 Future Research

Further research should be carried out in order to analyze the system's behavior with a deeper perspective, and to understand the uncertainties involved. One subject of a future study could be a sensitivity analysis of some of the many parameters and inputs that were used, such as the dates when the new power plants enter the system, the fuel prices, the natural gas availability, the power plant's maximum capacities, and the emission factors. This would give useful information about the dependency of the obtained results for the different parameters.

This study uses a simplified model to represent the operation of the SING, which does not include some processes and variables that have an impact on the results, such as the simulation of starting up and shutting down processes in the power plants, where the fuel consumption of the power plants is higher than the average values used in this study to estimate the annual fuel consumption. The magnitude of the impact of these processes in the results should be further studied with more complex models.

Another are that should be studied is the potential of the SING for the installation of renewable sources, because without this information, these technologies can be studied only from an unitary point of view. For geothermal energy, exploration costs and uncertainties should be included in its cost by doing, for example, a sensitivity analysis on its LCE.

Other scenarios could be modeled with the methodology of this study, such as an interconnection between the SING and the SIC, or an interconnection with the Bolivian electric system. This would require to change the electricity demand and some power plant information.

IV. CONCLUSIONS

An unified methodology is presented in this study, where concepts from different disciplines are used to provide answers from a complex system such as the SING. By joining mining, electricity, economic and environmental concepts, carbon emissions were estimated for the timeframe analyzed, and reduction costs for this emissions were estimated under different scenarios.

Annual carbon emissions of the SING caused by the electricity consumption of the Copper Mining Industry are expected to rise 130% between 2000 and 2012. 66.1% of this increase is due to the higher copper production; and 33.9% is accountable to the greater carbon-emitting energy mix expected for 2012, which will have an emission factor 23.8% higher than the emission factor of 2000.

Among evaluated carbon reduction measures, the one with the single highest emission reduction potential is coal to gas substitution, with a potential of reducing 2.3 millions of tons of carbon per year by 2012, representing 12% of the SING's emissions and 1.6% of Chile's expected emissions on that year, at an annual cost of 51 million US$, which would represent an increase of 10% in the system's annual variable costs. Coal by gas substitution has also social co-benefits, such as emissions reduction of particulate material, nitrogen oxides and sulfur dioxide (U.S. Environmental Protection Agency, 1995). This measure could be almost entirely financed by CER at market prices for this certifications above 20 US$ per ton of carbon.

If coal and petcoke are to become the main energy sources in the electric grid for the following years, the cheapest way to reduce the potential carbon emissions of the system is to use advanced generating technologies in the new power plants, as all of them produce very low or even negative costs when replacing technologies planned at present.

The petcoke-fired CFB technology can produce that highest savings to the system, with an estimate of 69.7 million US$ a year, and an annual carbon reduction potential of 0.7 millions of tons, which represents 3.7% of carbon reduction in the SING and 0.4% of Chile's expected emissions by 2012. The use of the IGCC technology can achieve annual savings of 5.7 million US$ a year by 2012, with a carbon reduction of 1.25 tons per year, representing 6.6% of the system's emissions and 1% of Chile's emissions.

The evaluated alternative with the highest carbon emission reduction is the combination of coal to gas substitution with the use of the IGCC. This alternative has a potential of reducing 3.5 millions of tons of carbon per year by 2012, which is 18.6% of the SING's emissions and 1.8% of Chile's expected emissions on 2012. The annual cost of this measure is 45 million US$, certainly lower than the cost of coal to gas substitution by itself, because of the annual savings generated by the use of the more efficient IGCC technology. This option has some hidden costs though, such as the fact that currently there are no power plants in Chile using the IGCC technology, so being the first-of-a-kind may require extra research and specialized labor work

Besides their carbon reduction potential, the use of more advanced technologies in the power plants could become a business opportunity to the Copper Mining Industry by the selling of the carbon reductions into the CER market, generating annual incomes above 25 million US$ for CER prices above 20 US$ per ton of CO_2.

Coal to diesel substitution can reduce up to 12% of the SING's emissions, but the annual cost of this alternative is about 130% of the SING's annual variable costs, which are expected to be 459 million US$ by 2012, thus this option should not be considered by the Copper Mining Industry unless no other fuel types are available. Supply security of electricity could be affected if broad diesel generation is incorporated on a permanent basis because logistic problems have been addressed for this fuel (Electricidad Interamericana, 2007c).

Further reduction in carbon emissions could be achieved with geothermal energy at an annual saving to the system of US$16.4 per ton of carbon, and with wind power at an average cost of US$79.5 per ton of carbon. The carbon reduction potential in the SING of these technologies should be estimated in future studies.

Further studies should also include a sensitivity analysis for some of the included variables in order to quantify their impact on the results. Further research should be carried out to model some additional operational aspects of the SING that were left out of this study, that produce a sub-estimation in carbon emissions of an unknown magnitude.

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ANNEX

A. SPECIFICATIONS ON THE ESTIMATION OF THE ELECTRICITY DEMAND OF THE SING

A.1. Copper Production in the SING between 2000 and 2012

The copper production projections until 2012 used in this study were made by the consultant González (2007), and are shown in Table A-1, among with his estimations of the copper production between 2000 and 2006 for the copper mines, smelters and the refinery connected to the SING.

Table A-1: Copper production until 2006 and projections until 2012, in thousands of metric tons of fine copper (González, 2007)

	Product type			
	SxEw Cathode	Concentrates	Blister	Electrolytic
2000	1226	1714	637	673
2001	1394	1592	637	708
2002	1460	1520	617	676
2003	1489	1711	633	656
2004	1475	2075	655	598
2005	1404	2084	748	576
2006	1517	2041	722	520
2007	1804	2096	755	580
2008	1985	2175	822	650
2009	2037	2091	881	700
2010	1927	2037	982	700
2011	1904	1916	975	750
2012	1785	2333	1223	800

A.2. Estimation the Electricity Demand of Regulated Clients

To estimate the electricity demand of the regulated clients (for a description of the types of clients in the SING refer to 3.3) an average annual growth rate of the demand was estimated for the years 2000-2006. This annual growth rate was then assumed to be constant in the following years. The past demand of the regulated clients is shown in the following Table:

Table A-2: Growth rate of the annual electricity demand of SING's *regulated clients* (CNE, 2007).

Year	Electricity Demand [GWh]	Annuar growth rate
2000	899	5.1%
2001	945	6.8%
2002	1009	3.8%
2003	1047	2.8%
2004	1076	7.7%
2005	1159	8.4%
2006	1256	
	Average rate	**5.8%**

A.3. Estimation the Electricity Demand of *Free Clients*

The estimation of the electricity demand of the *free clients* was divided into the estimation of the electricity demand of the Copper Mining Industry connected to the SING, as previously mentioned; and the estimation of the electricity demand for the rest of the *free clients*, which was estimated following the same methodology as above for the *regulated clients*. The only difference is that the average growth rate was calculated from 2001 and not 2000, because the growth rate in that year is clearly above the trend. Previous demand for the "rest of the free clients" was obtained subtracting the demand of the Copper Mining Industry from the demand for the total of the free clients, available from a publication by the CNE (2007a).

Table A-3: Growth rate of the annual electricity demand of SING's "rest of the *free clients*".

Year	Electricity Demand [GWh]	Annuar growth rate
2000	126	164.5%
2001	333	12.2%
2002	373	15.5%
2003	431	28.5%
2004	554	20.7%
2005	669	35.3%
2006	905	
	Average rate	**22.4%**

B. THE OPERATION MODEL OF THE SING

B.1. Power Plants Included in the Model

Table B-1: Power plants of the SING (CDEC SING, 2007e).

Company	Power Plant	Unit	Fuel type	Max. Gross Power [MW]
Celta	Tarapacá Thermoelectric	TGTAR	Diesel	23.8
		CTTAR	Coal	158.0
Edelnor	Chapiquiña	CHAP	Hidropower	10.2
	Arica Diesel	GMAR	Diesel	8.4
		M1AR	Diesel	3.0
		M2AR	Diesel	2.9
	Iquique Diesel	SUIQ	Diesel	4.2
		MIIQ	Diesel	2.9
		MAIQ	Diesel (24%) + Fuel Oil (76%)	5.9
		TGIQ	Diesel	23.8
		MSIQ	Diesel (23%) + Fuel Oil (77%)	6.2
	Antofagasta Diesel	MAAN	Diesel	11.9
		GMAN	Diesel	16.8
	Mejillones Thermoelectric	CTM1	Coal OR Coal (70%) + Petcoke (30%)	165.9
		CTM2	Coal OR Coal (70%) + Petcoke (30%)	175.0
		CTM3	Natural Gas OR Diesel	250.8
	Mantos Blancos Diesel	MIMB	Diesel (28%) + Fuel Oil (72%)	28.6
	Cavancha	CAVA	Hidropower	2.6
Electroandina	Tocopilla Thermoelectric	U10	Fuel Oil Nro. 6	37.5
		U11	Fuel Oil Nro. 6	37.5
		U12	Coal	85.3
		U13	Coal	85.5
		U14	Coal OR Coal (85%) + Petcoke (15%)	128.3
		U15	Coal OR Coal (85%) + Petcoke (15%)	130.3
		U16	Natural Gas	400.0
		TG1	Diesel	24.7
		TG2	Diesel	24.9
		TG3	Natural Gas OR Diesel	37.5
AES Gener	Combined Cycle Salta	CC SALTA	Natural Gas OR Diesel	642.8
Norgener	Norgener Thermoelectric	NTO1	Coal OR Fuel Oil Nro. 6	136.3
		NTO2	Coal OR Fuel Oil Nro. 6	141.0
	Zofri Diesel	ZOFRI_1-6	Diesel	0.9
		ZOFRI_2-5	Diesel	5.2
Gasatacama Generación	Combined Cycle Atacama	CC1	Natural Gas OR Diesel	395.9
		CC2	Natural Gas OR Diesel	384.7
	Enaex Diesel	DEUTZ	Diesel	0.7
		CUMMINS	Diesel	2.0

B.2. Availability Factors

Table B-2: Availability factors for the power plants of the SING. Maintenance factors and operation margins obtained from different sources (CDEC SING, 2007g, 2007h; J. Venegas, personal communication, August 16, 2007).

Power Plant	Unit	Fuel type	Maintenance Factor	Operation Margin	Availability Factor
Tarapacá Thermoelectric	TGTAR	Diesel		48.3%	**51.7%**
	CTTAR	Coal	8.5%	7.0%	**84.5%**
Chapiquiña	CHAP	Hidropower		41.0%	**59.0%**
Arica Diesel	GMAR	Diesel		41.0%	**59.0%**
	M1AR	Diesel		59.0%	**41.0%**
	M2AR	Diesel		56.9%	**43.1%**
Iquique Diesel	SUIQ	Diesel		44.0%	**56.0%**
	MIIQ	Diesel		53.5%	**46.5%**
	MAIQ	Diesel (24%) + Fuel Oil (76%)		45.4%	**54.6%**
	TGIQ	Diesel		43.6%	**56.4%**
	MSIQ	Diesel (23%) + Fuel Oil (77%)		79.4%	**20.6%**
Antofagasta Diesel	MAAN	Diesel		53.0%	**47.0%**
	GMAN	Diesel	15.1%	41.8%	**43.1%**

Table B 2: Availability factors for the power plants of the SING. Maintenance factors and operation margins obtained from different sources (CDEC SING, 2007g, 2007h; J. Venegas, personal communication, August 16, 2007).

Power Plant	Unit	Fuel type	Maintenance Factor	Operation Margin	Availability Factor
Mejillones Thermoelectric	CTM1	Coal	15.1%	7.0%	**77.9%**
	CTM1	Coal (70%) + Petcoke (30%)	15.1%	7.0%	**77.9%**
	CTM2	Coal	15.1%	7.0%	**77.9%**
	CTM2	Coal (70%) + Petcoke (30%)	15.1%	7.0%	**77.9%**
	CTM3	Diesel	5.5%	12.3%	**82.2%**
	CTM3	Natural Gas	5.5%	12.3%	**82.2%**
Mantos Blancos Diesel	MIMB	Diesel (28%) + Fuel Oil (72%)		55.0%	**45.0%**
Cavancha	CAVA	Hidropower		43.0%	**57.0%**
Tocopilla Thermoelectric	U10	Fuel Oil Nro. 6	5.5%	7.0%	**87.5%**
	U11	Fuel Oil Nro. 6	5.5%	7.0%	**87.5%**
	U12	Coal	1.9%	7.0%	**91.1%**
	U13	Coal	6.8%	7.0%	**86.2%**
	U14	Coal	11.0%	7.0%	**82.0%**
	U14	Coal (85%) + Petcoke (15%)	11.0%	7.0%	**82.0%**
	U15	Coal	4.7%	7.0%	**88.3%**
	U15	Coal (85%) + Petcoke (15%)	4.7%	7.0%	**88.3%**
	U16	Natural Gas	9.6%	20.0%	**70.4%**
	TG1	Diesel	2.7%	55.7%	**41.5%**
	TG2	Diesel	2.7%	57.4%	**39.9%**
	TG3	Diesel	6.8%	40.1%	**53.1%**
	TG3	Natural Gas	6.8%	59.9%	**33.3%**
Combined Cycle Salta	CC SALTA	Diesel	1.4%	53.0%	**45.6%**
	CC SALTA	Natural Gas	1.4%	53.0%	**45.6%**
Norgener Thermoelectric	NTO1	Coal	13.7%	7.0%	**79.3%**
	NTO1	Fuel Oil Nro. 6	13.7%	7.0%	**79.3%**
	NTO2	Coal	13.7%	7.0%	**79.3%**
	NTO2	Fuel Oil Nro. 6	13.7%	7.0%	**79.3%**
Zofri Diesel	ZOFRI_1-6	Diesel		45.0%	**55.0%**
	ZOFRI_2-5	Diesel		45.0%	**55.0%**
Combined Cycle Atacama	CC1	Diesel		19.0%	**81.0%**
	CC1	Natural Gas		19.0%	**81.0%**
	CC2	Diesel	11.5%	15.0%	**73.5%**
	CC2	Natural Gas	11.5%	15.0%	**73.5%**
Enaex Diesel	DEUTZ	Diesel		12.7%	**87.3%**
	CUMMINS	Diesel		60.7%	**39.3%**

B.3. Natural Gas Availability

Table B-3: Natural gas restrictions until August 2007 (CNE, 2007b)

Year	Period	Expected NG Volume [Mm^3]	Restricted Volume [Mm^3]	NG Availability [%]
2004	Jan-Apr	N/A	0.0	100%
	May-Aug	296.7	64.3	78%
	Sep-Dec	489.5	41.0	92%
	Annual	**786.2**	**105.2**	87%
2005	Jan-Apr	567.1	143.3	75%
	May-Aug	424.0	77.1	82%
	Sep-Dec	380.7	66.0	83%
	Annual	**1371.7**	**286.4**	79%
2006	Jan-Apr	520.2	147.4	72%
	May-Aug	527.2	318.5	40%
	Sep-Dec	258.0	56.1	78%
	Annual	**1305.4**	**522.0**	60%
2007	Jan-Apr	307.1	88.7	71%
	May-Aug	310.6	280.7	10%

Table B-4: Natural gas availability for Salta Power Plant in 2007 (CDEC SING, 2007i)

Month	Natural Gas Availability
January	100%
February	100%
March	99%
April	99.5%
May	82%
June	69.3%
July	10.2%
August	1.7%
September	34%

B.4. Effective Net Power

Table B-5: Effective net generating capacities (in power units and without gas shortage), and own consumption values of the power plants (CDEC SING, 2007e).

Power Plant	Unit	Fuel type	Own consumption [%]	Effective Net Power [MW]
Tarapacá Thermoelectric	TGTAR	Diesel	0.4%	12.2
	CTTAR	Coal	6.0%	125.51
Chapiquiña	CHAP	Hidropower	0.6%	6.0
Arica Diesel	GMAR	Diesel	0.5%	4.9
	M1AR	Diesel	2.7%	1.2
	M2AR	Diesel	2.7%	1.2
Iquique Diesel	SUIQ	Diesel	3.3%	2.3
	MIIQ	Diesel	3.8%	1.3
	MAIQ	Diesel (24%) + Fuel Oil (76%)	5.1%	3.1
	TGIQ	Diesel	0.8%	13.3
	MSIQ	Diesel (23%) + Fuel Oil (77%)	4.8%	1.2
Antofagasta Diesel	MAAN	Diesel	4.9%	5.3
	GMAN	Diesel	0.8%	7.2
Mejillones Thermoelectric	CTM1	Coal	6.6%	120.7
	CTM1	Coal (70%) + Petcoke (30%)	6.6%	120.7
	CTM2	Coal	6.3%	127.8
	CTM2	Coal (70%) + Petcoke (30%)	6.3%	127.8
	CTM3	Diesel	3.0%	200.0
	CTM3	Natural Gas	3.0%	200.0
Mantos Blancos Diesel	MIMB	Diesel (28%) + Fuel Oil (72%)	2.5%	12.6
Cavancha	CAVA	Hidropower	0.4%	1.5
Tocopilla Thermoelectric	U10	Fuel Oil Nro. 6	4.0%	31.5
	U11	Fuel Oil Nro. 6	4.0%	31.5
	U12	Coal	6.7%	72.5
	U13	Coal	6.7%	68.7
	U14	Coal	6.4%	98.5
	U14	Coal (85%) + Petcoke (15%)	6.4%	98.5
	U15	Coal	6.4%	107.7
	U15	Coal (85%) + Petcoke (15%)	6.4%	107.7
	U16	Natural Gas	1.8%	276.7
	TG1	Diesel	0.4%	10.2
	TG2	Diesel	0.4%	9.9
	TG3	Diesel	0.8%	19.7
	TG3	Natural Gas	0.8%	12.4
Combined Cycle Salta	CC SALTA	Diesel	1.6%	288.7
	CC SALTA	Natural Gas	1.6%	288.7
Norgener Thermoelectric	NTO1	Coal	6.5%	101.1
	NTO1	Fuel Oil Nro. 6	6.5%	101.1
	NTO2	Coal	6.5%	104.6
	NTO2	Fuel Oil Nro. 6	6.5%	104.6
Zofri Diesel	ZOFRI_1-6	Diesel	0.0%	0.5
	ZOFRI_2-5	Diesel	0.0%	2.8
Combined Cycle Atacama	CC1	Diesel	3.3%	313.1
	CC1	Natural Gas	1.6%	315.5
	CC2	Diesel	2.3%	287.2
	CC2	Natural Gas	1.6%	278.2
Enaex Diesel	DEUTZ	Diesel	0.5%	0.6
	CUMMINS	Diesel	0.5%	0.8

B.5. Power Plants Variable Costs

Table B-6: Non-fuel variable costs (NFVC) and fuel variable costs (FVC) of the power plants of the SING.

Power plant	Unit	Fuel type	Fuel consumption rate	Units	NFVC mills/kWh	FVC 2007 mills/kWh	FVC 2008 mills/kWh	FVC 2009 mills/kWh	FVC 2010 mills/kWh	FVC 2011 mills/kWh	FVC 2012 mills/kWh
Tarapacá Thermoelectric	TGTAR	Diesel	0.33	kg/kWh	0.41	225.53	217.71	200.87	185.08	170.44	158.59
	CTTAR	Coal	0.45	kg/kWh	1.40	27.00	27.20	27.13	27.22	26.60	26.13
Chapiquiña	CHAP	Hydropower	0.00		0	0	0	0	0	0	0
Arica Diesel	GMAR	Diesel	0.25	kg/kWh	9.20	169.21	163.35	150.72	138.86	127.88	118.99
	M1AR	Diesel	0.26	kg/kWh	9.20	173.13	167.13	154.20	142.08	130.84	121.74
	M2AR	Diesel	0.26	kg/kWh	9.20	172.59	166.61	153.72	141.63	130.43	121.36
Iquique Diesel	SUIQ	Diesel	0.28	kg/kWh	9.90	187.04	180.56	166.59	153.49	141.35	131.52
	MIIQ	Diesel	0.26	kg/kWh	9.90	173.06	167.07	154.14	142.02	130.79	121.70
	MAIQ	Diesel (24%) + Fuel Oil (76%)	0.26	kg/kWh	7.90	99.66	99.03	93.48	87.25	81.52	76.89
	TGIQ	Diesel	0.32	kg/kWh	1.70	218.51	210.93	194.62	179.31	165.13	153.65
	MSIQ	Diesel (23%) + Fuel Oil (77%)	0.23	kg/kWh	4.70	94.13	93.72	88.61	82.77	77.42	73.08
Antofagasta Diesel	MAAN	Diesel	0.27	kg/kWh	9.30	185.55	179.12	165.27	152.27	140.23	130.48
	GMAN	Diesel	0.24	kg/kWh	10.40	165.36	159.63	147.29	135.71	124.97	116.28
Mejillones Thermoelectric	CTM1	Coal	0.43	kg/kWh	2.08	26.33	26.52	26.46	26.54	25.95	25.48
	CTM1	Coal (70%) + Petcoke (30%)	0.43	kg/kWh	2.08	27.68	27.46	26.95	26.54	25.70	25.02
	CTM2	Coal	0.42	kg/kWh	2.56	25.15	25.33	25.27	25.35	24.78	24.34
	CTM2	Coal (70%) + Petcoke (30%)	0.42	kg/kWh	2.56	26.44	26.23	25.74	25.34	24.54	23.90
	CTM3	Diesel	0.22	kg/kWh	1.40	145.58	140.54	129.67	119.47	110.02	102.37
	CTM3	Natural Gas	0.21	m3/kWh	1.40	26.06	25.84	23.78	22.63	20.99	20.38
Mantos Blancos Diesel	MIMB	Diesel (28%) + Fuel Oil (72%)	0.24	kg/kWh	9.00	99.73	98.95	93.30	87.02	81.25	76.58
Cavancha	CAVA	Hydropower	0		0	0	0	0	0	0	0
Tocopilla Thermoelectric	U10	Fuel Oil Nr. 6	0.29	kg/kWh	1.19	94.44	95.76	91.79	86.39	81.47	77.49
	U11	Fuel Oil Nr. 6	0.29	kg/kWh	1.19	94.44	95.76	91.79	86.39	81.47	77.49
	U12	Coal	0.51	kg/kWh	2.97	30.96	31.18	31.11	31.20	30.50	29.95
	U13	Coal	0.49	kg/kWh	2.97	29.59	29.80	29.73	29.82	29.15	28.63
	U14	Coal	0.47	kg/kWh	2.00	28.65	28.86	28.79	28.88	28.23	27.72
	U14	Coal (85%) + Petcoke (15%)	0.46	kg/kWh	3.00	0.00	0.00	0.00	0.00	0.00	0.00

Table B-6: Non-fuel variable costs (NFVC) and fuel variable costs (FVC) of the powerplants of the SING (continuation).

Power plant	Unit	Fuel type	Fuel consumption rate	Units	NFVC mills/kWh	FVC 2007 mills/kWh	FVC 2008 mills/kWh	FVC 2009 mills/kWh	FVC 2010 mills/kWh	FVC 2011 mills/kWh	FVC 2012 mills/kWh
Tocopilla Thermoelectric	U15	Coal	0.46	kg/kWh	2.00	27.94	28.15	28.08	28.17	27.53	27.04
	U15	Coal (85%) + Petcoke (15%)	0.45	kg/kWh	5.00	0.00	0.00	0.00	0.00	0.00	0.00
	U16	Natural Gas	0.19	m3/kWh	0.80	23.68	23.48	21.61	20.57	19.08	18.52
	U16	GNL regasificado	0.19	m3/kWh	0.80	0.00	0.00	45.76	43.56	40.40	39.23
	TG1	Diesel	0.33	m3/kWh	0.99	225.74	217.92	201.07	185.26	170.60	158.74
	TG2	Diesel	0.33	m3/kWh	0.99	225.74	217.92	201.07	185.26	170.60	158.74
	TG3	Diesel	0.26	m3/kWh	0.99	178.10	171.93	158.63	146.16	134.60	125.24
	TG3	Natural Gas	0.34	m3/kWh	0.99	42.45	42.10	38.73	36.87	34.20	33.20
Combined Cycle Salta	CC SALTA	Diesel	0.15	kg/kWh	1.60	102.00	98.47	90.85	83.71	77.09	71.73
	CC SALTA	Natural Gas	0.19	m3/kWh	4.60	13.38	13.27	12.21	11.62	10.78	10.46
Norgener Thermoelectric	NTO1	Coal	0.40	kg/kWh	1.66	24.27	24.44	24.38	24.46	23.91	23.48
	NTO1	Fuel Oil Nr. 6	0.22	kg/kWh	9.60	70.54	71.53	68.57	64.53	60.86	57.88
	NTO2	Coal	0.40	kg/kWh	1.63	24.04	24.21	24.15	24.23	23.68	23.26
	NTO2	Fuel Oil Nr. 6	0.22	kg/kWh	9.40	70.54	71.53	68.57	64.53	60.86	57.88
Zofri Diesel	ZOFRI_1-6	Diesel	0.29	kg/kWh	5.00	193.79	187.08	172.61	159.03	146.46	136.27
	ZOFRI_2-5	Diesel	0.29	kg/kWh	2.00	193.79	187.08	172.61	159.03	146.46	136.27
Combined Cycle Atacama	CC1	Diesel	0.18	kg/kWh	2.95	121.38	117.17	108.11	99.61	91.73	85.35
	CC1	Natural Gas	0.21	m3/kWh	2.32	26.43	26.21	24.12	22.96	21.30	20.68
	CC2	Diesel	0.18	kg/kWh	2.95	121.38	117.17	108.11	99.61	91.73	85.35
	CC2	Natural Gas	0.21	m3/kWh	2.32	26.43	26.21	24.12	22.96	21.30	20.68
Enaex Diesel	DEUTZ	Diesel	0.33	kg/kWh	15.00	222.83	215.11	198.47	182.86	168.40	156.69
	CUMMINS	Diesel	0.3	kg/kWh	14.00	202.57	195.55	180.43	166.24	153.09	142.45

Table B-6: Non-fuel variable costs (NFVC) and fuel variable costs (FVC) of the power plants of the SING (continuation).

Power plant	Unit	Fuel type	Fuel consumption rate	Units	NFVC mills/kWh	FVC 2007 mills/kWh	FVC 2008 mills/kWh	FVC 2009 mills/kWh	FVC 2010 mills/kWh	FVC 2011 mills/kWh	FVC 2012 mills/kWh
Angamos Thermoelectric	CTANG1	Coal	0.40	kg/kWh	2.08				24.31	23.76	23.34
	CTANG2	Coal	0.40	kg/kWh	2.08					23.76	23.34
	CTANG3	Coal	0.40	kg/kWh	2.08					23.76	23.34
	CTANG4	Coal	0.40	kg/kWh	2.08						23.34
Andino Thermoelectric	CTA1	Coal	0.38	kg/kWh	2.88				23.03	22.51	22.11
	CTA1	Petcoke	0.28	kg/kWh	2.88				16.88	15.99	15.24
	CTA2	Coal	0.38	kg/kWh	2.88					22.51	22.11
	CTA2	Petcoke	0.28	kg/kWh	2.88					15.99	15.24
El Tatio-La Torta Geothermal	Tatio1	Geothermal	0		0					0	0
	Tatio2	Geothermal	0		0					0	0
Kelar Thermoelectric	CTKEL1	Coal	0.40	kg/kWh	2.08					23.34	23.34
	CTKEL2	Coal	0.40	kg/kWh	2.08						23.34
Apacheta Geothermal	Apacheta1	Geothermal	0								0

B.6. New Power Plants Technical Information

Table B-7: Technical information on Kelar Thermoelectric (New Coal Generación S.A., 2006).

Company	New Coal Generación S.A. (CODELCO & BHP)
Technology	Pulverized coal - Sub-critical
Fuel type	Coal/Petcoke mix
Gross power per unit [MW]	250
Own consumption per unit [MW]	28.4
Efficiency (HHV)	35%-36%
Number of units	2

Table B-8: Estimated and assumed parameters for Kelar Thermoelectric.

Coal consumption [kg/kWh]	0.4	estimated
Annual maintenance	5%	assumed
Operation margin	7%	assumed
Availability factor	88%	estimated
NFVC [US mills/kWh]	2.08	assumed, same value from Mejillones Power Plant
Carbon Emission Factor [ton CO_2/GWh]	1018.9	estimated

Table B-9: Technical information on Angamos Thermoelectric (Norgener S.A., 2006).

Company	Norgener S.A.
Technology	Pulverized coal - Sub-critical
Fuel type	Coal
Gross power per unit [MW]	150
Number of units	4

Table B-10: Estimated and assumed parameters for Angamos Thermoelectric.

Own consumption per unit [MW]	17.04 (11.4%)	assumed
Efficiency HHV	36%	assumed
Coal consumption [kg/kWh]	0.4	estimated
Annual maintenance	5%	assumed
Operation margin	7%	assumed
Availability factor	88%	estimated
NFVC [US mills/kWh]	2.08	assumed, same value from Mejillones Power Plant
Carbon Emission Factor [ton CO_2/GWh]	1018.9	estimated

Table B-11: Technical information on Andino Thermoelectric (Suez Energy Andino S.A., 2006).

Technology	Combusting Fluidized Bed (CFB)
Fuel type	Coal / Petcoke
Gross power per unit [MW]	200
Own consumption per unit [MW]	16
Efficiency (HHV)	38%
Number of units	2

Table B-12: Estimated and assumed parameters for Andino Thermoelectric.

Coal consumption [kg/kWh]	0.38	estimated
Petcoke consumption [kg/kWh]	0.28	estimated
Annual maintenance	5%	assumed
Operation margin	7%	assumed
Availability factor	88%	estimated
NFVC [US mills/kWh]	2.88	Assumed. Based on DOE's value (1999) shown in Table E-1
Coal operating - Carbon Emission Factor [ton CO_2/GWh]	855	estimated
Petcoke operating - Carbon Emission Factor [ton CO_2/GWh]	950	estimated

B.6.1 Geothermal Power Plants: El Tatio-La Torta and Apacheta

Table B-13: Technical information on the geothermal power plants (Empresa Nacional de Geotermia, 2007).

Technology	Geothermal - Flash
El Tatio-La Torta Gross power[MW]	80
Apacheta Gross power [MW]	40

Table B-14: Estimated and assumed parameters for geothermal power plants.

Own consumption [% of gross gen]	5%	based on a report from Department of Electricity - Universidad de Chile (2003)
Availability factor	95%	based on a report from Department of Electricity - Universidad de Chile (2003)
Variable costs [US c/kWh]	0	based on a report from Department of Electricity - Universidad de Chile (2003)

B.7. Fuel Prices

Table B-15: Fuel prices and annual variations from *reference scenario* of Annual Energy Outlook 2007 (U.S. Department of Energy, 2007a).

Year	Coal		Natural Gas		Diesel		Fuel Oil		Crude	
	Price [US$/Mbtu]	Annual variation	Price [US$/Mbtu]	Annual variation	Price [US c/gal]	Annual variation	Price [US c/gal]	Annual variation	Price [US$/barrel]	Annual variation
2007	1.7		7.2		197.8		107.7		59.5	
2008	1.7	0.7%	7.2	-0.8%	191.0	-3.5%	109.2	1.4%	57.2	-3.8%
2009	1.7	-0.2%	6.6	-8.0%	176.2	-7.7%	104.7	-4.1%	54.2	-5.3%
2010	1.7	0.3%	6.3	-4.8%	162.3	-7.9%	98.5	-5.9%	51.2	-5.6%
2011	1.7	-2.3%	5.8	-7.3%	149.5	-7.9%	92.9	-5.7%	48.5	-5.3%
2012	1.6	-1.8%	5.7	-2.9%	139.1	-7.0%	88.4	-4.9%	46.2	-4.7%

Table B-16: Fuel prices used in the electric grid's operation model.

	Diesel [US$/m3]	Natural Gas (Chile) [US$/m3]	Natural Gas (Salta) [US$/m3]	Fuel Oil Nr. 6 [US$/m3]	Coal [US$/ton]	Petcoke [US$/ton]	LNG [US$/m3]
2000	153.7	0.036	0.035	104.5	27.2		
2001	189.6	0.044	0.046	120.0	34.9		
2002	176.3	0.048	0.048	147.6	34.6		
2003	251.7	0.046	0.045	167.9	36.2		
2004	320.5	0.052	0.052	176.8	56.0	19.4	
2005	464.2	0.065	0.069	251.1	64.7	21.7	
2006	535.3	0.097	0.075	316.3	58.7	36.7	
2007	567.2	0.127	0.069	304.6	60.5	70.8	
2008	547.5		0.068	308.9	61.0	68.1	
2009	505.2		0.063	296.1	60.8	64.6	0.245
2010	465.5			278.7	61.0	61.0	0.233
2011	428.7			262.8	59.6	57.7	0.216
2012	398.8			250.0	58.6	55.0	0.210

C. CARBON EMISSIONS MODEL

C.1. Low and High Heating Values

Table C-1: Low and high heating values (LHV & HHV) used in this study (CNE, 2006; CDEC SING, 2007b; IPCC, 2006)

Fuel type	Units	HHV [GJ/ton]	LHV [GJ/ton]
Coal	GJ/ton	25.1	23.8
Natural Gas	GJ/m3	0.0391	0.0352
Petroleum Coke	GJ/ton	34.2	32.5
Diesel	GJ/ton	45.6	43.3
Fuel Oil	GJ/ton	43.9	41.7

HHV for natural gas, diesel and fuel oil were obtain from the CNE's national energy balance (2006); coal's HHV of 6000 kcal/kg was obtained from the CDEC SING (2007b); and petcoke's LHV was obtained from an IPCC report (2006).

LHV were assumed a 95% of HHV for all of the fuels with the exception of natural gas, for which LHV was assumed to be an 90% of the HHV. All of this, based on International Energy Agency's conversion equivalents (International Energy Agency , 2004).

C.2. Emission Factors of the Fuels

Table C-2: Greenhouse gas emission factors of fuels (IPPC, 2006).

Fuel type	CO2 Emision Factor [kg/GJ]	CH_4 Emision Factor [g/GJ]	N_2O Emision Factor [g/GJ]
Coal	94.6	1	1.5
Natural Gas	56.1	1	0.1
Petroleum Coke	97.5	3	0.6
Diesel	74.1	3	0.6
Fuel Oil	77.4	3	0.6

C.3. Emission Factors of the Power Plants

Table C-3: Estimated carbon emission factors of the power plants.

Power Plant	Unit	Fuel type	Efficiency (HHV)	Carbon emission factor [ton CO_2/Gwh]
Tarapacá Thermoelectric	TGTAR	Diesel	23.6%	1080.4
	CTTAR	Coal	32.2%	1075.7
Chapiquiña	CHAP	Hydropower		0.0
Arica Diesel	GMAR	Diesel	31.5%	811.1
	M1AR	Diesel	30.8%	848.5
	M2AR	Diesel	30.9%	846.5
Iquique Diesel	SUIQ	Diesel	28.5%	923.0
	MIIQ	Diesel	30.8%	857.8
	MAIQ	Diesel (24%) + Fuel Oil (76%)	7.4%	876.2
	TGIQ	Diesel	24.4%	1050.8
	MSIQ	Diesel (23%) + Fuel Oil (77%)	8.0%	774.2
Antofagasta Diesel	MAAN	Diesel	28.7%	930.6
	GMAN	Diesel	32.2%	795.0

Table C-3: Estimated carbon emission factors of the power plants (continuation).

Power Plant	Unit	Fuel type	Efficiency (HHV)	Carbon emission factor [ton CO_2/Gwh]
Mejillones Thermoelectric	CTM1	Coal	33.0%	1056.2
	CTM1	Coal (70%) + Petcoke (30%)	23.1%	1181.1
	CTM2	Coal	34.5%	1005.1
	CTM2	Coal (70%) + Petcoke (30%)	24.2%	1123.9
	CTM3	Diesel	36.6%	715.9
	CTM3	Natural Gas	44.7%	419.2
Mantos Blancos Diesel	MIMB	Diesel (28%) + Fuel Oil (72%)	9.3%	786.1
Cavancha	CAVA	Hydropower		0.0
Tocopilla Thermoelectric	U10	Fuel Oil Nr. 6	28.0%	988.9
	U11	Fuel Oil Nr. 6	28.0%	988.9
	U12	Coal	28.0%	1242.6
	U13	Coal	29.3%	1187.6
	U14	Coal	30.3%	1146.3
	U14	Coal (85%) + Petcoke (15%)	29.5%	1181.6
Tocopilla Thermoelectric	U15	Coal	31.1%	1118.0
	U15	Coal (85%) + Petcoke (15%)	30.5%	1144.7
	U16	Natural Gas	49.2%	376.2
	U16	GNL regasificado	23.6%	1081692.5
	TG1	Diesel	23.6%	1081.6
	TG2	Diesel	29.9%	856.4
	TG3	Diesel	27.5%	667.8
	TG3	Natural Gas	27.5%	667.8
Combined Cycle Salta	CC SALTA	Diesel	52.3%	494.3
	CC SALTA	Natural Gas	47.5%	389.5
Norgener Thermoelectric	NTO1	Coal	35.8%	971.9
	NTO1	Fuel Oil Nr. 6	37.4%	758.5
	NTO2	Coal	36.1%	962.7
	NTO2	Fuel Oil Nr. 6	37.4%	758.5
Zofri Diesel	ZOFRI_1-6	Diesel	27.5%	924.5
	ZOFRI_2-5	Diesel	27.5%	924.5
Combined Cycle Atacama	CC1	Diesel	43.9%	598.7
	CC1	Natural Gas	44.1%	419.3
	CC2	Diesel	43.9%	592.8
	CC2	Natural Gas	44.1%	419.3
Enaex Diesel	DEUTZ	Diesel	23.9%	1068.3
	CUMMINS	Diesel	26.3%	971.2
Angamos Thermoelectric	CTANG1	Coal	36.0%	1018.9
	CTANG2	Coal	36.0%	1018.9
	CTANG3	Coal	36.0%	1018.9
	CTANG4	Coal	36.0%	1018.9
Andino Thermoelectric	CTA1	Coal	38.0%	924.1
	CTA1	Petcoke	38.0%	950.1
	CTA2	Coal	38.0%	924.1
	CTA2	Petcoke	38.0%	950.1
El Tatio-La Torta Geothermal	Tatio1	Geothermal		0.0
	Tatio2	Geothermal		0.0
Kelar Thermoelectric	CTKEL1	Coal	36.0%	1019.0
	CTKEL2	Coal	36.0%	1019.0
Apacheta Geothermal	Apacheta1	Geothermal		0.0

D. VALIDATION OF THE SING'S OPERATION MODEL

Table D-1: Comparison of real and simulated fuel generation by source type in the SING.

	REAL					SIMULATED				
Year	Coal + Petcoke	Diesel	Natural Gas	Fuel Oil	Hydropower	Coal + Petcoke	Diesel	Natural Gas	Fuel Oil	Hydropower
2001	29.1%	0.4%	69.4%	0.4%	0.7%	31.5%	0.0%	67.9%	0.0%	0.7%
2002	36.7%	0.2%	62.4%	0.1%	0.6%	31.5%	0.0%	67.9%	0.0%	0.6%
2003	26.7%	0.1%	72.5%	0.1%	0.6%	26.3%	0.0%	73.1%	0.0%	0.6%
2004	37.3%	0.2%	61.5%	0.4%	0.5%	38.1%	0.0%	61.3%	0.0%	0.5%
2005	35.9%	0.1%	63.5%	0.1%	0.5%	36.1%	0.0%	63.4%	0.0%	0.6%
2006	49.9%	0.7%	48.4%	0.5%	0.5%	50.0%	0.0%	49.5%	0.0%	0.5%

Table D-2: Comparison of real (estimated) and simulated carbon emissions in the SING.

	REAL - estimated		SIMULATED		
Year	Annual Carbon Emissions [Mton]	Emission Factor [ton/GWh]	Annual Carbon Emissions [Mton]	Emission Factor [ton/GWh]	Simulation Error
2001	5.69	605.8	5.60	596.8	-1.5%
2002	6.49	656.8	6.04	611.8	-6.8%
2003	6.46	591.0	6.03	551.8	-6.6%
2004	7.45	634.5	7.57	644.4	1.6%
2005	8.02	665.0	7.63	632.6	-4.9%
2006	9.19	732.5	9.22	735.2	0.4%

E. DATA USED IN THE ESTIMATION OF LEVELISED COSTS OF ELECTRICITY

Table E-1: Original values used in the estimation of levelised costs of electricity's (LCE).

Technology	Availability factor	Investment	Units	Annual fixed costs	Units	Non-fuel variable costs	Units	Dollar year	Lifetime	Source
PC Boiler - sub-critical	88%	1129	US$/kW	22.8	US$/kW	0.22	US c/kWh	1999 investment, 2005 m&o	30	U.S. Department of Energy (1999)
PF Boiler - supercritical	88%	1173	US$/kW	23.41	US$/kW	0.35	US c/kWh	1999 investment, 2005 m&o	30	U.S. Department of Energy (1999)
IGCC	88%	1229	US$/kW	35.6	US$/kW	0.19	US c/kWh	1999 investment, 2005 m&o	30	U.S. Department of Energy (1999)
CFB	88%	1001	US$/kW	29.64	US$/kW	0.28	US c/kWh	1999 investment, 2005 m&o	30	U.S. Department of Energy (1999)
Geothermal Flash	95%	349440000	US$ (300 gross MW)	10857406	US$	0	US c/kWh	2002	30	Departamento de Ingeniería Eléctrica - Unversidad de Chile (2003)
Windpower	34%	2349714	US$/MW	1.76	US$/MWh	10	US$/MWh	2007	20	Pavez (2008)
Solar PV	15%	5500	US$/kW	0.15	% installed price	0	US c/kWh	1997	30	U.S. Department of Energy (2006a)

The efficiency value used in the LCE calculation of the pulverized-coal sub-critical technology was a 36%, as this represents the average coal-fired power plant in the SING. For the CFB technology an efficiency value used was a 39%, as it is the expected efficiency of the coal/petcoke-fired Andino power plant. For pulverized-coal supercritical and IGCC the original report's values were used: 39.9% and 45.4% respectively. The same approach was used on the own electricity consumption values of the technologies. Geothermal and wind power costs were transformed to an unitary basis.

Table E-2: Estimated coal and petcoke prices between 2012 and 2030.

	Coal US$/ton	Petcoke [US$/ton]
2012	58.6	55.0
2013	58.0	53.6
2014	57.7	52.9
2015	57.3	53.1
2016	57.0	53.4
2017	56.9	53.8
2018	56.4	54.3
2019	56.5	54.8
2020	56.6	55.3
2021	56.9	56.1
2022	57.2	56.8
2023	57.3	57.6
2024	57.8	58.3
2025	58.3	59.0
2026	58.7	59.5
2027	59.1	60.0
2028	59.6	60.5
2029	59.9	61.0
2030	60.5	61.5
Average	**57.90**	**56.66**

Table E-3: Estimated levelised cost of electricity (LCE) for different technologies. All values in 2006 USD.

Technology	Fuel	Investment [US$/kW]	Annual fixed costs [US$/kW]	Non-fuel variable costs [US c/kWh]	Efficiency (HHV)	Consumer price index factor	LCE [US c/kWh]
PC Boiler - sub-critical	coal	1484.7	23.48	0.2266	36.0%	1.21 inv, 1.03 o&m	**5.21**
PF Boiler - supercritical	coal	1542.8	24.11	0.3605	39.9%	1.21 inv, 1.03 o&m	**5.03**
IGCC	coal	1631.1	36.67	0.1957	45.4%	1.21 inv, 1.03 o&m	**5.13**
CFB	coal	1331.0	30.53	0.2884	39.0%	1.21 inv, 1.03 o&m	**4.96**
CFB	petcoke	1331.0	30.53	0.2884	39.0%	1.21 inv, 1.03 o&m	**4.28**
Geothermal Flash		1304.6	40.53	0		1.12	**2.15**
Wind power		2349	0	1		-	**9.76**
Solar PV		6930.0	34.65	0		1.26	**58.58**

Table E-4: Comparison of LCE values for geothermal energy. In all the cases a 95% availability factor and a 30 years lifetime were assumed.

Source	Investment	Units	Annual fixed costs	Units	Money year	Dollar conversion factor[4]	Consumer price index factor	LCE [2006 US c/kWh]
Departamento de Ingeniería Eléctrica - Unversidad de Chile (2003)	349440000	US$ (300 gross MW)	10857406	US$	2002	1	1.2	2.15
Danish Energy Authority	1.1	M€/MW	3.2	€/MW	2002	1.0483	1.2	1.65
(NZ) Avaliability and Costs of Renewable Sources of Energy for Generating Electricity	3200	NZ$/kW	93	NZ$/kw	2002	0.526	1.2	3.06

[4] Dollar conversion factors were obtained from the online tool FXHistory (OANDA, 2007)

F. CARBON MITIGATION CURVES FOR RENEWABLE ENERGY SOURCES

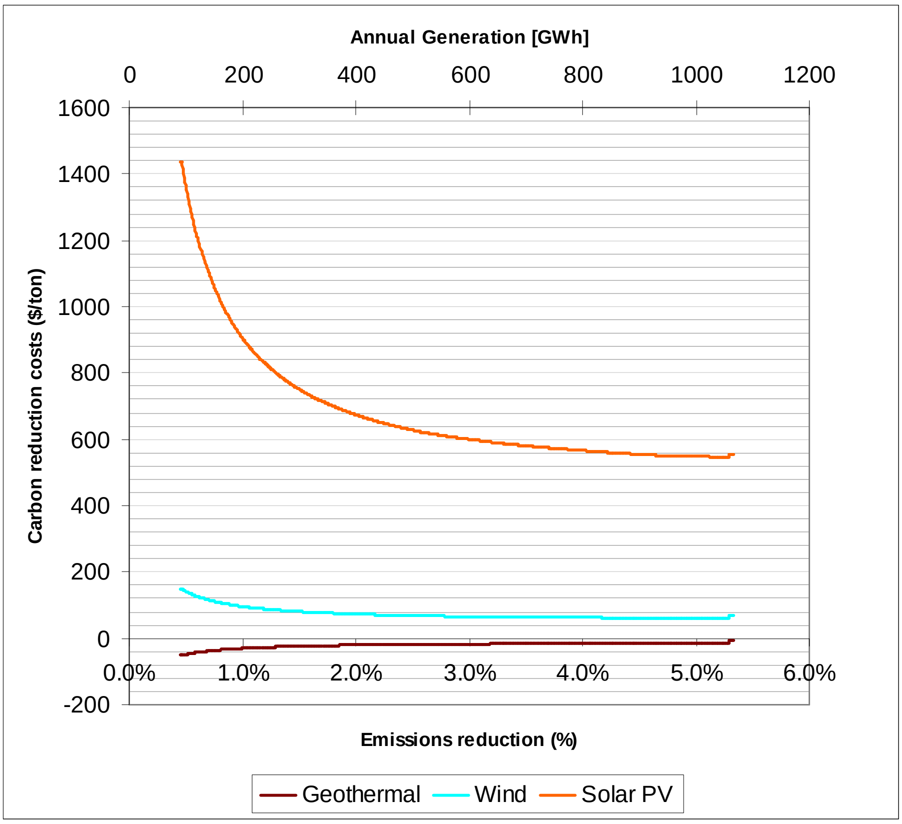

Figure F-1: Carbon emissions reduction costs curves for renewable technologies

(*PV: photovoltaic*)

ABBREVIATIONS AND ACRONYMS

CDEC	Centro de Despacho Económico de Carga
CDM	Clean Development Mechanism
CER	Certified Emission Reduction
CFB	Combusting fluidized bed
CNE	Comisión Nacional de Energía
COCHILCO	Comisión Chilena del Cobre
ER	Electro-refined
FVC	Fuel variable costs
GDP	Gross domestic product
GWP	Global Warming Potential
HHV	High heating value
HM	Her Majesty
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel for Climate Change
LCE	Levelised cost of electricity
LHV	Low heating value
LNG	Liquefied Natural Gas
MTF	Mega-tons of fine
MW	Mega-watt
NFVC	Non-fuel variable costs
NG	Natural Gas
PC	Pulverized coal
PF	Pulverized fuel
PV	Photovoltaic
SING	Sistema Interconectado del Norte Grande
SX-EW	Solvent extraction/electrowinning