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

CONTENTS

Annexes

SECTION A. General description of project activity

A.1 Title of the project activity:

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La Higuera Hydroelectric Project, Chile
Version number: Version 2
Date: 01 December 2005

A.2. Description of the project activity:

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Purpose of project activity

The La Higuera Project (hereafter, the Project) is being developed by Hidroeléctrica La Higuera S.A. (HLH), a joint venture between Pacific Hydro Limited (PHL), through its subsidiary Pacific Hydro Chile S.A (PHC), and Statkraft Norfund Power Invest (SNPI). The purpose of the project is to utilise the hydrological resources of the Tinguiririca and Azufre Rivers in a run of river scheme to generate zero emission energy to the Chilean Central electricity grid (SIC). The Project will generate certified emission reductions (CERs) by displacing electricity generation from grid connected fossil fuel-fired power plants that would otherwise be generating electricity.

In May 2001 PHC secured an option to purchase the water rights. It has taken 2 years of intense negotiation to finalise a Power Purchase Agreement, which was only executed in June 2005. In May 2004 a power purchase agreement (PPA) was signed in principle with SAESA, the forth-largest distributor in Chile with concessions in the southern portions of SIC. However, negotiations on this contract could not be finalised, mainly due to the financing requirements of the Projects' potential Lenders not being acceptable to SAESA. In May 2004 PHL sold down part of its ownership of the project by 50% to SNPI. In August 2004 the Project was granted Environmental Approval (EIA) by the Chilean Government. In February 2005 Host Country Approval was granted by the Chilean DNA. Based on annual estimated generation of 811 GWh the project will reduce CO_2 emissions by an estimated 477,586 tonnes per annum.

The Project will contribute to the social welfare of the 6th region, Chile, where local employment opportunities and infrastructure are poor. Construction of the Project will last 30 months, with the Contractor required to source at least 30% of its workforce locally. Road access to the valley and its upper reaches is limited to a few months in summer due to the treacherous nature of the road. Road access will be improved to year-round access, opening up the area to income generating activities including tourism, to fully utilise the natural resources such as thermal springs, climbing and other recreational activities.

Contribution to sustainable development

As mentioned above, host country approval for the project issued by the Chilean DNA has already been received. The Designated National Authority checked the project against the sustainable development criteria of the country, finding that La Higuera project contributes towards meeting those.

The Project is also particularly relevant to the sustainable development of the Chilean electricity sector, which is currently undergoing a fuel supply crisis. Following the introduction of imported Argentinean natural gas in 1996, most additional capacity needs have been met by combined cycle natural gas plants.

However, in 2004 Argentina restricted the exports of natural gas into Chile and subsequent gas restrictions have forced many of these plants to reduce generation and use diesel where environmental permissions exist. As a result of this the Chilean Government is actively seeking alternative forms of energy to supply a system with an internal growth demand of 350-400 MW per annum. Unfortunately, renewable energies are not a priority, favouring again more thermal energy like coal fired plants. The role of the project in contributing to the sustainable development of Chile and its additionality in such a scenario is a clear demonstration of the value of the Project.

A.3. Project participants:

Name of Party involved ((host) indicates a host Party)	Private and/or public entity(ies) project participants (as applicable)	Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)
Chile (host)	Hidroeléctrica La Higuera S.A	NO

Table 1 - Project participants

Contact details information on project participants are provided in Annex 1.

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

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The Project will be located in the valley of the Tinguiririca River. This river rises in the Andes Mountains about 120km south of Santiago and flows westward to the Pacific Ocean. The nearest major city to the project area is San Fernando. The area of the Project activity is shown in Figure 1 below.

Figure 1 - Location of Project Activity

A.4.1.1. Host Party(ies):

>>
Chile

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

>>
6th Administrative Region, Chile

A.4.1.3. City/Town/Community etc:

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The nearest community to the Project is Puente Negro, approximately 15kms downstream from the powerhouse. The nearest city is San Fernando, which is on the PanAmerican Highway, 120 km south of the capital city, Santiago.

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

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The Project is located in the Tinguiririca Valley, specifically between the elevations of 1100 m.a.s.l. to 728 m.a.s.l as shown in Figure 2.

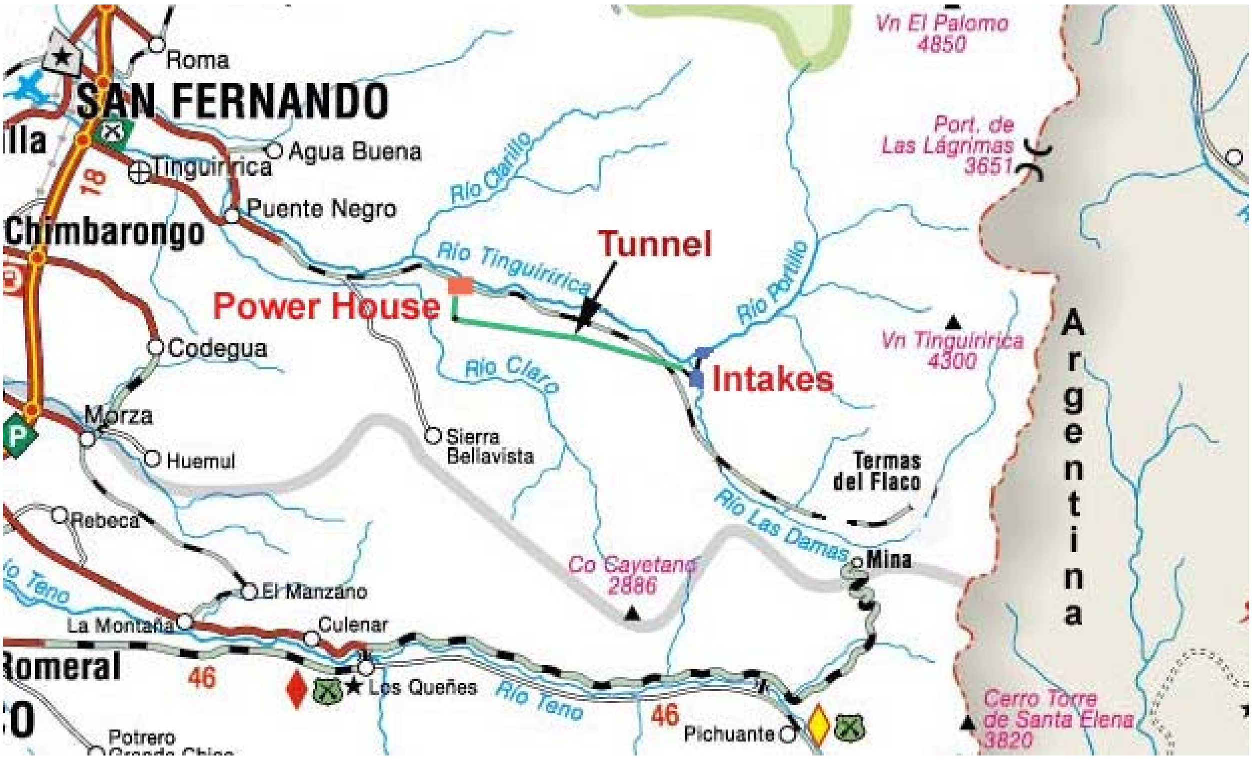

Figure 2 - Location of Project Activity

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

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Sectoral Category 1, Energy Industries (renewable/non renewable)

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

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The project considers an intake on the Azufre River at 1104 m.a.s.l, diverting partial flows via a canal and tunnel to the Tinguiririca intake. Water from the Tinguiririca River, including the water from the Azufre intake, is diverted via a weir at 1100 m.a.s.l. into desanding bays on the south bank of the Tinguiririca. This water is then conveyed some 17km in a 5m diameter tunnel with a design flow of 50 m^3/s into an off channel reservoir of 500,000m^3 capacity. Water is conveyed through a tunnel and steel pipe from this off channel head pond to a surge shaft and valve chamber, where it enters a surface steel penstock of 600m length. The La Higuera powerhouse is located on the south bank of the Tinguiririca at around 715 m.a.s.l. The tailrace returns the diverted flows to the river approximately 100m downstream of the powerhouse. Electricity is transmitted approximately 38km along a 154kv high tension transmission line to a substation near the town of San Fernando, where it joins the SIC grid.

The Project will use state of the art but known technology in electricity generation and transmission. In particular the vertical axis Francis turbines will be provided by Power Machines (Russian company), generators by Electrosila and transformers to be appointed. Both companies have been utilising these forms of technology for a number of decades, while control and safety systems are state of the art. Specifically this is the first application of Francis turbines in a high head project in Chile.

La Higuera Project		
Gross head	385m	
Machine type	2 x 77.5MW Francis	
Design Flow	50m^3/s	
Installed Capacity	155 MW	
Annual average Generation	*834.7 GWh*	
Storage facilities	***Surface area***	***Capacity***
Off channel	41,000m^2	500,000 m^3

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

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How the emissions are reduced

La Higuera hydro plant will reduce emissions by displacing electricity generated from fuel-based power plants. La Higuera hydro plant is a run-of-river with no project emissions associated with its operations. The current structure of the SIC is such that the generation mix capacity comprises of 60% hydroelectric generation, 30% natural gas, and the remainder from coal, diesel, petcoke and cogeneration. The coal, petcoke, petroleum and diesel plants have the highest marginal costs, and as the SIC uses least cost order of merit dispatch these plants are typically the marginal operating plants in the system. Any run of river plant, with zero marginal cost, as such displaces these plants to the extent of its generation when these plants would have otherwise been dispatched. As such there is a clearly demonstrable reduction in GHG emissions from the introduction of La Higuera into the SIC system.

Why the emission reductions would not occur otherwise

La Higuera will be the second biggest run of river project ever built by installed capacity in Chile[1]. In 1991 the 160 MW Alfalfal plant was built on the Colorado River, some 80km north of the La Higuera project. This project is similar in many ways to La Higuera project, however, the economics of the Alfalfal project were significantly better for two main reasons. Firstly, in 1991 there was no gas available, and as such node prices for energy were significantly higher than current prices. The second factor is that the owners, GENER, also have coal fired thermal plants, allowing them to mitigate the high seasonal generation of low winter generation and high summer snow melt generation.

Following the introduction of imported natural gas from Argentina in 1996 there was significant change in the electricity sector's structure, with high growth in the lower capital cost and shorter payback period combined cycle natural gas plants as shown in Figure 3. This resulted in a significant reduction in node prices. This has increased the barriers to hydroelectricity and other renewable energy technologies, which are typically much higher capital cost investments.

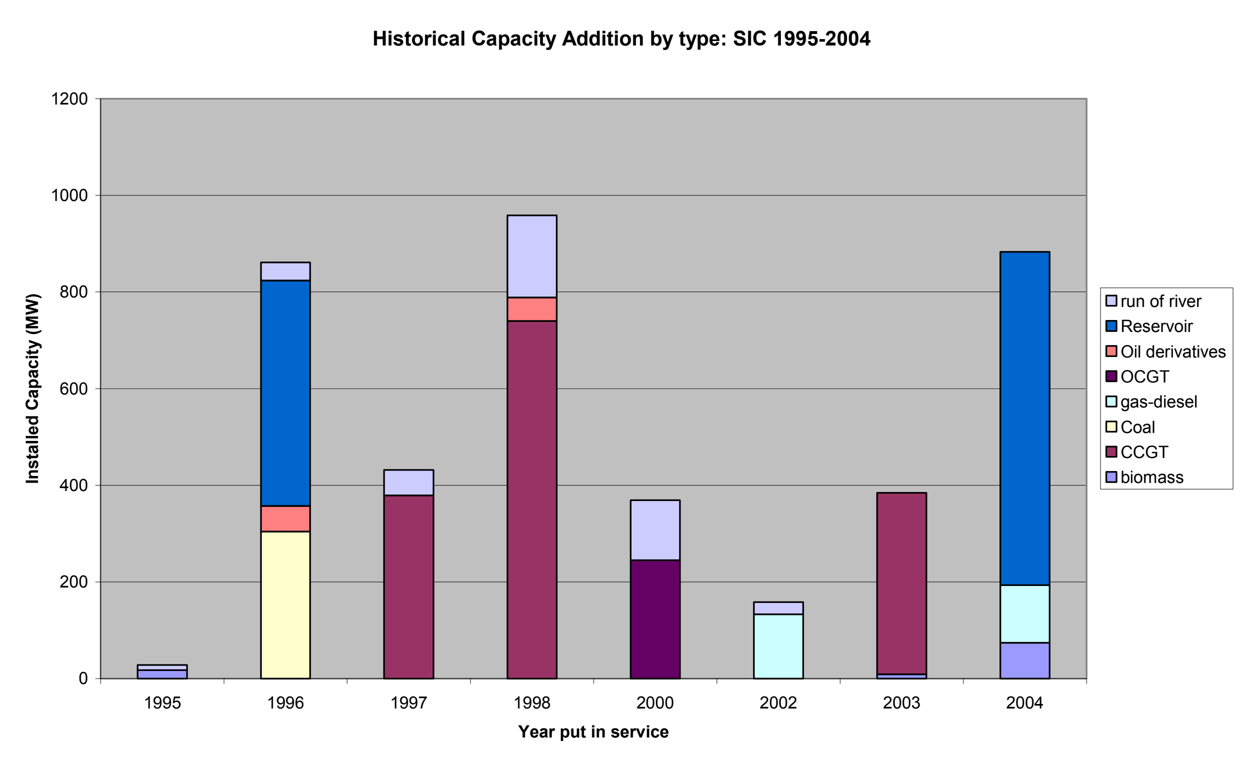

Figure 3 - Historical Capacity Addition By type SIC 1995 - 2004

Total emissions reductions:

In total, the project is estimated to reduce emissions of greenhouse gases by 3,343,104t CO_2e over a period of 7 years.

[1] This does not include run of river plants associated with large reservoirs, which provide annual regulation, and as such should not be considered as run of river projects.

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

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The project will displace electricity from a more carbon-intensive grid with an estimated combined margin emission factor of 0.589 tCO_2/MWh. The project is expected to displace 811 GWh of electricity per year, thus reducing GHG emissions by 477,586 tCO_2e per year in the baseline scenario.

Years	Annual estimation of emission reductions in tonnes CO_2e
1	477,586
2	477,586
3	477,586
4	477,586
5	477,586
6	477,586
7	477,586
Total estimated reductions (tonnes of CO_2e)	3,343,102
Total number of crediting years	7
Annual average over the crediting period of estimated reductions (tonnes of CO_2e)	477,586

Table 2 - Estimation of emission reductions in tonnes of CO_2e for the crediting period

Refer to section E for further details on the quantification of GHG emission reductions associated with this project.

A.4.5. Public funding of the project activity:

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There is no public funding being provided to the project.

SECTION B. Application of a baseline methodology

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

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ACM0002: "Consolidated baseline methodology for grid-connected electricity generation from renewable sources".

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

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The project activity is a grid connected run-of-river hydropower project, where the grid's geography and system boundaries are explicit and characteristics are readily available through CNE and CDEC-SIC. As a renewable energy project it is appropriate to follow Paragraph 48 of Marrakech Accords and use existing actual or historical emissions, since the project activity will serve to reduce actual emissions. On this basis the conditions for applying ACM0002 are met.

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

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Applying the methodology ACM0002 "Consolidated baseline methodology for grid-connected electricity generation from renewable sources", the implementation of the La Higuera project will reduce on average 477,586 tCO_2 per annum. The defaults used for the calculation of calorific values for fuel types and fuel oxidization, come from the IPCC GHG Gas Inventory Reference Manual (IPCC 1996).

This is based on the baseline scenario established as the likely future scenario based on the most recent expansion of the system, the Build Margin, as provided for in ACM0002. The Operating Margin, as defined in ACM0002, uses hourly order of merit dispatch data from the central regulator, CDEC, to determine actual dispatch, compared with what would have been dispatched if the project was absent. Emission factors for each plant are known through the monthly publication by CDEC of fuel types used for electricity generation. This allows the determination of an ex post baseline Emission Factor for the project activity. The methodology will be applied using Option (c) of the Consolidated Methodology for Grid Connected Projects, as this is the most complete of the options. The data used for the calculation of build margin is shown in Annex 3 of this document. The main source of data is CDEC-SIC.

Emission Reductions

$$ER_y = BE_y - PE_y - L_y$$

Where:

- ER: Emission reduction (t CO_2e)
- BE: Baseline emissions (t CO_2e)
- PE: Project Emissions (t CO_2e)
- L: Leakage emissions (t CO_2e)
- y: a given year

Baseline Emissions:

The baseline emission factor calculations will be based on the combined margin using the "Dispatch Data Analysis Operating Margin", option (c) of the ACM0002, according to the following formulae:

$$BE_y = GEN_y * EF_y$$

Where:

BE: Baseline emissions (t CO_2e)
GEN: Electricity supplied by the project to the grid (MWh)
EF: baseline emission factor (tCO_2e / MWh)
y: a given year

Where:

$$EF_y = \omega_{OM} * EF\_OM_y + \omega_{BM} EF\_BM_y$$

Where:

EF: baseline emission factor (tCO_2e / MWh)
ω_{OM}: Operation Margin weight, which is 0.5 by default
EF_OM: Operational Margin emission factor (tCO_2e / MWh)
ω_{BM}: Build Margin weight, which is 0.5 by default
EF_BM: Build Margin emission factor (tCO_2e / MWh)
y: a given year

and

$$EF_{OM,Dispatch\ Data,y} = E_{OM,y} / EG_y$$

$$E_{OM,y} = \sum_h EG_h \cdot EF_{DD,h}$$

Where EG_y is the generation of the project (in MWh) in year y and $E_{OM,\ y}$ are the emissions (tCO_2) associated with the operating margin calculated by:

$$EF_{DD,h} = \frac{\sum_{i,n} F_{i,n,h} \cdot COEF_{i,n}}{\sum_n GEN_{n,h}}$$

EG_h is the generation of the Project in each hour and $EF_{DD,\ h}$ is the hourly generation-weighted average emissions per electricity unit (tCO_2/MWh) of the set of power plants (*n*) in the top 10% of the grid system dispatch order during hour *h*.

Where $F_{i,\ n,\ h}$ is the amount of fuel (mass or volume) *i* consumed by relevant power sources *n* in hour(s) h, *n* is the set of power sources within the top 10% of the dispatch centre, $COEF_{i,\ n}$ is the CO_2 emissions coefficient of fuel (tCO_2/mass or volume) for the relevant power sources *n* and $GEN_{n,h}$ is the electricity (MWh) delivered to the grid by the relevant power sources *n*.

$$EF\_BM_y = \frac{\sum_{i,m} F_{i,m,y} * COEF_{i,m}}{\sum_m GEN_{j,y}}$$

Where:

EF_BM: Build Margin emission factor (tCO_2e / MWh) and
m: refers to last additions power sources delivering electricity to the grid.

$$COEF_{i,n} = NCV_i \cdot EF_{CO2} \cdot OXID_i$$

Where NCV_i is the net calorific value per mass or volume of of fuel
$OXID_i$ is the oxidation factor of of the fuel; and
EF_{CO2} is the CO_2 emission factor per unit of energy of fuel i.

The following table provides the key information and data used to determine the baseline scenario:

Variable	Unit	Data Source
Estimated Dispatch Data Analysis Operating Margin Emissions Factor (EF_OM_y in tCO_2/MWh)	0.817	Calculated using data from CDEC-SIC
Build Margin Emissions Factor (EF_BM_y in tCO_2/MWh)	0.361	Calculated using data from CDEC-SIC
Baseline Emissions Factor (EF_y in tCO_2/MWh)	0.589	Calculated using data from CDEC-SIC
Electricity generated by Project (*EG* MWh)	811,000	Hidroeléctrica La Higuera S.A
Baseline Emissions (*BE* tCO_2)	477,586	Calculated

Table 3 - Data used to determine the baseline scenario

B.3. Description of how the anthropogenic emissions of GHG by sources are reduced below those that would have occurred in the absence of the registered CDM project activity:

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The determination of project scenario additionality is done using the CDM consolidated tool for demonstration of additionality, which follows the following steps:

Step 0. Preliminary screening based on the starting date of the project activity

The project is only expected to start construction in the first quarter of 2006, which is after November 18 2004 (date of registration of first CDM project), thus crediting period will start at the point of registration of the project. In any case, as it will be demonstrated in the following steps, CDM revenue has been considered from the early stages of development of the project, and it is an integral part of the financial package of the project.

Step 1. Identification of alternatives to the project activity consistent with current laws and regulations

***Sub-step 1a*. Alternatives to the project activity**
Alternative options to the project activity include:
- run of river project without CDM assistance;
- natural gas combined; and
- open cycle plants (coal and diesel plants).

***Sub-step 1b*. Enforcement of applicable laws and regulations**

Under the Chilean Electricity Law all the alternatives to the project activity are in compliance with applicable legal and regulatory requirements. No special benefits are established under Chilean laws for renewable energies.

Step 3. Barrier Analysis

Following the guidelines for determining additionality there are two analytical options available: investment analysis and barrier analysis. Due to the nature of the project and the important barriers it faces barrier analysis is used. The following barriers have been identified as the crucial barriers affecting the owners in undertaking the project activity.

***Sub-step 3a.* Identify barriers that would prevent the implementation of type of the proposed project activity:**

Hydrological risk:

Hydrology risk is perhaps the greatest risk facing the project as a run of river project with only 5 hours of storage capacity. This capacity allows for storage of 5 hours of design flows discharge during the period of lowest inflows. On this basis during the winter months of April to August the storage would only be sufficient to ensure that the plant could operate for 5 hours each day via discharging the storage and replenishing it for the following day’s generation. As a result there is no way the project can mitigate against drought and low inflow periods. If large dams were built on both the Tinguiririca and Azufre Rivers then high summer inflows, where available water in the rivers is generally in excess of capacity of the project, could provide for monthly storage and discharge of the reservoir when the system has less water. Due to almost 100% exposure to meteorological and hydrological risk project returns are highly variable. Figure 4 shows the annual generation the project would have generated based on historical hydrology.

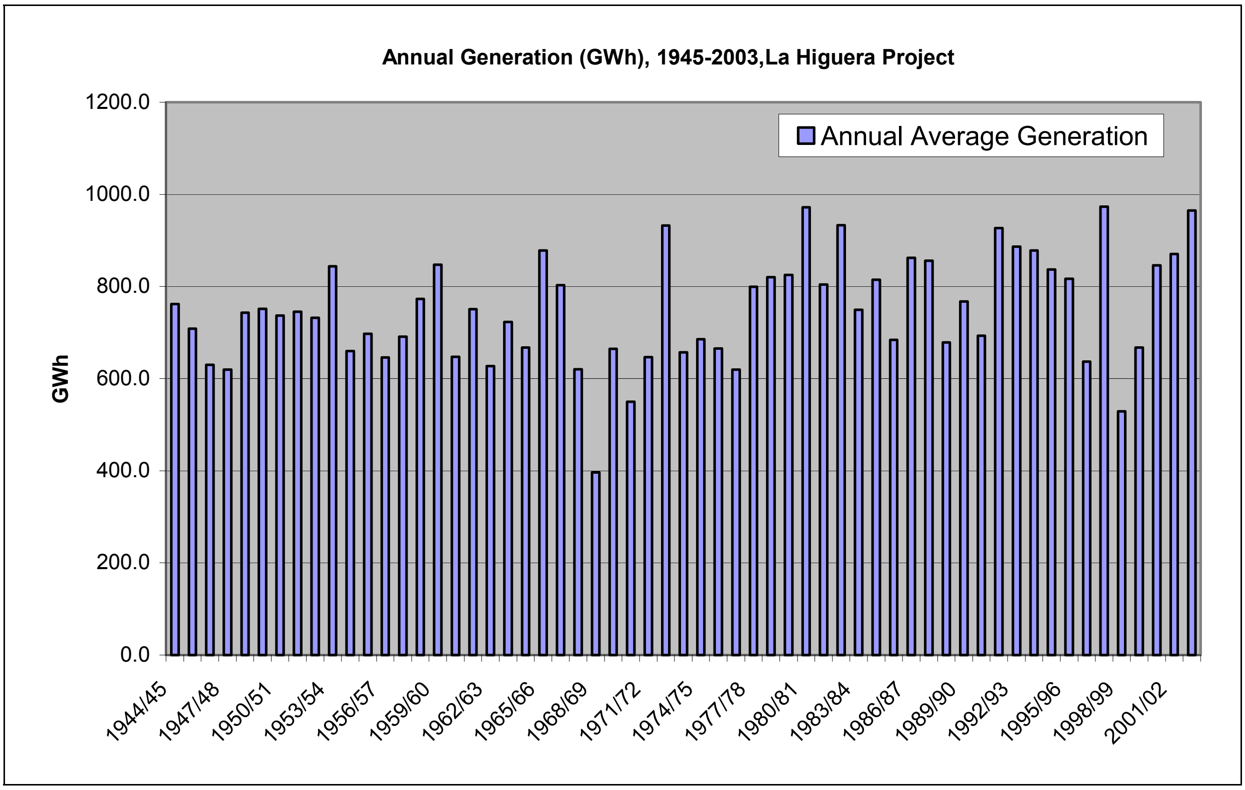

Fig 4 *Source: EPS Ingienera*

Tunnelling risk:

The project has 17km of tunnels to convey water from the intake to the surge shaft and penstock facility, where it is taken to the powerhouse. Because of the very steep alpine terrain, it is not possible to convey the water through canals, which are much cheaper than tunnels. As a result, the rock conditions for tunnelling are critical to final project cost. The construction company can only rely on surface mapping to base their cost estimates on, and hence there are considerable unknowns. It is not practical to drill sections of the tunnel from the surface, as this information is insufficient for 17km of section. As such risks such as underground water, geotechnical quality and presence of gases have to be taken by the Owner, and not the contractor.

The Owner's Engineer, SwedPower/Golder Associates, have projected an expected worst case overrun of $3.8m on tunnelling costs. However, the Lender's Independent Engineer, Montgomery Watson Harza, have estimated a more pessimistic scenario of $6m in possible tunnelling overruns. On this basis the Project has had to increase the contingency for the project. This amount formed part of the initial expected contingency of $12m. However, in light of this increase and other increases the Project has had to increase the Project Contingency to $20m to satisfy the Lenders. Delays in tunnelling also expose the Project to completion risk, since the contractor is allowed extensions of time for *force majeure* events, such as encountering underground gases, high water inflows and other natural events. This is industry standard and cannot be avoided. The failure to complete the project on time could make the Project liable under the power supply agreement they have had to sign to obtain financing for the project (see below).

Land Risk:

While the project area is sparsely populated during summer time grazing periods, there are 11 landowners in the immediate project area, and another 60 along the route of the transmission line. These landowners have considerable power in extracting payments from the project above market rates to avoid delays. The project developer could try and enforce sale under the Chilean Electricity Law code, but this is a drawn out procedure and does not foster the relationship with stakeholders the company is seeking. In particular the project construction timetable of 30 months assumes that access is to be completed to 2 intermediate adits along the route of the tunnel that would provide additional faces critical for completing the drill and blasting of the tunnels. To settle this issue the Project had to pay over market rates for the land and provide services such as telephones and power to the land owner, which is a significant cost item.

The project is also being forced into an unfavourable position by one part owner of an estate where the powerhouse is to be situated. The partner of one of the heirs to this estate has refused to enter into an agreement that the other 6 heirs entered into. Instead, he demanded an exorbitant payment 10 times higher than the fair value accepted by the other owners. This is an untenable situation and the Project has investigated relocating the powerhouse to avoid this estate. However, following additional engineering studies, the only other possible location is not feasible as it is not located on bedrock. The new site for the powerhouse would require at least 35m of additional excavation to reach bedrock. While this would slightly increase the generation of the Project, the cost is in the order of $10m additional investment. This is not an economical alternative. Of even more importance to the Project is the delay in receiving a new Environmental Permit (at least 6 months) and a new Hydraulic Works Permit (4 months) if forced to relocate the powerhouse. To ensure the project is not delayed the Owners may have to pay well over market rates to secure access.

Similar barriers are not faced by natural gas fired plants, for example, where total project area is a lot smaller and there is much more flexibility to optimally locate based on land issues.

Financing Risk:

The Project company, Hidroeléctrica La Higuera, is a 50% JV between PHL and SNPI. PHL has AU$271m in net assets, and this project as a whole would represent 113% of the company's net assets. As such it is not possible to secure the project investment via corporate financing and the company's balance sheet. On this basis the company sold 50% of the project to SNPI in May 2004, to reduce its funding commitment. As SNPI has only been in operation for 3 years as a development fund it is not able to fund projects via balance sheet financing. As a result the project has had to seek non recourse project finance, where only the assets of the project secure the loan. Banks require 50-100% of revenue to be subject to sales contract to PPAs to guarantee funds for debt payments. Typically Debt Service Cover Ratios of 2 or higher are required where the lenders have some exposure to spot market risk (merchant risk). The blackouts in California highlighted this exposure of the power sector, and as result banks are very risk averse to any spot market exposure. In the first half of 2003, the Sponsors approached the commercial market for non recourse project financing. Given the Californian situation, the power and corporate crisis triggered by Argentinean devaluation, and Brazilian energy crisis, no commercial banks would make non recourse project financing available for longer than 6 years. They also included a requirement for contracting the sale of 100% of plant generation. As discussed above the project could not support supply risk of 100% contractual obligations, and hence had to seek alternative sources.

In June 2003 the Project entered into a Mandate Letter with IFC to raise financing of the project. IFC is the World Bank's private investment bank, with a mandate to finance private companies and projects in under developed and developing countries. They typically only enter into projects and countries that Commercial Banks will not do on their own right, or at very unfavourable terms to the borrowers. On this basis they are known in the market as 'lenders of last resort'.[2] As such the requirements they place on borrowers are much more onerous and not what is obtainable under commercial financing. They also do not underwrite the deal, so if enough banks cannot be enticed to join the syndication, the project remains unfinanced. They are similarly limited to 25% of the project costs, so that commercial banks at the end of the day take up the largest part of the financing.

The Project has recently received provisional financing commitments from Syndicate banks through an IFC syndication process. The following is the probable financing composition for the Project:

SOURCE	**$US(000s)**	**%**
Debt		
IFC A Loan	35,000	13.3%
Syndicated B Loan	115,000	43.7%
IFC C Loan	10,000	3.8%
Total Debt	160,000	60.8%
Equity		
PHL	51,500	19.6%
SNPI	51,500	19.6%
Total Equity	103,000	39.2%
Total Project Funding	**263,000**	**100.0%**

Table 4 Financing Plan

Spot Market Risk:

Any generation activity has an element of spot market risk, since prices are a result of market forces, in this case fuel costs and hydrology are the main price factors. As the SIC has a 60% hydroelectricity base variability of spot prices is exaggerated. During a normal or wet hydrological year spot prices are very low, severely impacting project revenues. As mentioned above the project activity does not have any storage allowing for flow regulation so project will also suffer periods of very high spot prices when there is a drought, and it has no ability to regulate flows. As discussed below there is contracting risk as a result of being required to have a power purchase agreement (PPA) in place for lenders. HLH were recently able to obtain a PPA from Chilectra, Chile's largest distributor, by providing energy at a discount to the regulated node prices. While this is confidential information this discount is in the order of $US600,000-1,000,000 p.a. in foregone revenue to the project. This type of discount is not market practice with incumbent generators. This discount was the lowest that Chilectra would accept for a new company entering the system, and is related to their perceived uncertainty of project completion and the lack of other assets the company, HLH, has to supply under this PPA. Under non-recourse project financing the banks' only security on receiving principal and interest (PI) payments is contracted energy sales. The high levels of revenues from contracted sales required to meet the PI (generally 1.3 to 1.75 times greater than PI) increases the project exposure to spot market to supply the client. This exposes the project to spot market risk in the months of April-August when contract commitments can be higher than plant generation. If there is a drought in these periods the project would have to purchase off the spot market to fulfil its contract with the offtaker.

Market and Regulatory risk:

[2] A. Hawser. A Matter of Principles. *GLOBAL FINANCE MAGAZINE, January 2005*

Despite being a highly developed, deregulated and transparent system, the Chilean Electricity sector is still subject to changes that provide considerable barriers to the project. The first example of this is the introduction of Article 99bis, following a severe drought in 1999. Generators were unable to supply under their contracts to distributors and claimed *force majeure*. To try and reduce the likelihood of blackouts in the future, the authorities removed drought as an allowable *force majeure* event, thus making the generators responsible for finding other ways of securing delivery. The result has been that generators without a diverse portfolio of hydro and thermal generation assets have not been able to sign PPAs with distributors, who fall under Article 99bis jurisdiction. Since distributors are 80% of the market for sales, it severely limits the project to find financially attractive PPA to ensure financing.

The second example is current changes being made by CNE with respect to the period for which Firm Capacity is calculated. In October 2004, they changed the 5 hour period between 6 and 11 pm between the months of May and September to 8 hours. As the project has very limited ability for storage, currently only 5 hours due to geographical and environmental constraints, CDEC would downgrade the assigned firm capacity of the Plant. Firm capacity revenues for 5 hours represent 30% of project revenues, and changing to an 8 hour period would reduce firm capacity revenues by 37%.

Sub-step 3b. Show that the identified barriers would not prevent the implementation of at least one of the alternatives

Natural gas combined or open cycle plants are considered the least cost investment by CNE, the governmental Electricity Authority. On this basis CNE uses combined cycle gas plants as the default investment in planning system expansion, "Plan de Obras". They can easily be shown to not suffer the barriers identified above.

Hydrology Risk:

Natural gas plants are not constrained by hydrological conditions. While there may be some fuel supply risk for these plants they typically can run on either natural gas or diesel, the latter of which is readily available.

Tunnelling Risk:
Technological risk, in particular tunnelling is not relevant to gas fired plants. Construction techniques and technology are well established, resulting in a lower investment cost.

Land Risk:
The physical requirements for land for a combined cycle natural gas plant are considerably less than the proposed project activity. Indeed these plants can typically be built almost anywhere provided there is the ability to transport and access natural gas. This project activity is specifically tied to the unique characteristics of the topography, utilising available water and optimising construction cost with gross head. As such the project is dependent on the willingness and reasonableness of landowners in the project area. The Owner has experienced lengthy and negative sentiment by some of the landowners in the area, actually being forced to change the layout of the project once already.

Financing Risk:
In Chile the electricity generation sector is entirely open to investment by any company. The type of financing used is obviously dependent on size and the corporate strategies each investor has. However,

due to hydrology risk, large scale run of river hydroelectric projects would require the investor to have their own alternate thermal generation, or upstream regulation. As such, large scale projects in general would be restricted to companies with an installed base of thermal assets, or if not the latter, the ability to raise financing without high contracted power sale levels. A natural gas plant does not face the same funding hurdles.

A 350MW combined cycle plant will typically have an investment cost of $US208m, compared with the 155 MW La Higuera plant of $US225m. The project activity is also not the most cost effective investment when annualised costs of production are considered. Table 4 shows that the annualised cost of investment and generation of a natural gas plant over the net present generation during the life of the plant is lower for a natural gas plant than for the project activity[3].

Summary		
	La Higuera Project Activity	Combined Cycle Gas
Investment Cost ($m)	225.0	207.6
Annual Fixed Costs ($m)	3	3.4
Annual generation (GWh)	823	2818
PV of Energy (GWh)	4,804.6	19,781.1
PV of Annual and investment costs ($m)	-$215,536.11	-$742,006.54
Average cost of generation $US/MWh	44.9	37.5

Table 5 - Average annualised cost of generation comparison

Spot Market Risk:
As discussed above natural gas plants are also able to use diesel, thus mitigating supply risks that run of river projects, like the project activity, face. On this basis this barrier is not as extreme for a natural gas plant as the project activity.

Market and Regulatory risk:
As mentioned the project is particularly susceptible to changes in regulation governing the authority's recognition of the plants firm power. Water, environmental and geographical restraints restrict the ability for the project to adapt. A natural gas plant does not face the same restrictions, and generally such flexibility has a lower capital cost for these types of projects.

On the basis of the above analysis it is obvious that the project activity faces unique, identifiable and significant barriers, not faced by its most likely alternative, a gas fired plant.

Step 4. Common Practice analysis

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

[3] 11% discount rate is used for both technologies. Given the longer construction period, high risk geographical location and hydrological exposure for the Project Activity it would be appropriate to consider a higher discount rate for the Project Activity. For conservatism the same rate for both options has been used for this analysis.

Large Run of River hydroelectric projects that are not connected to reservoir facilities are not common within SIC. The following table lists the hydropower plants connected to the Chilean electricity grid constructed over the last 25 years. From the table below, the only plants of similar size are Rucúe and Alfalfal. Rucue is downstream of the Laja reservoir, and is able to directly benefit from the storage facility of this very large dam. As such it has a very different hydrological risk to a run of river project that has no storage facility upstream.. The other similar plant is Alfalfal. This plant was built in 1991 (16 years ago) when the energy and financing situation where completely different and cannot be compared with the current situation. This will be discussed in the next section.

Name of Project	Installed Capacity	Year of completion	Associated with large reservoirs
Chacabuquito	25	2002	no
Mampil	49	2000	no
Peuchén	75	2000	no
Rucúe	170	1998	Laja
Puntilla	14.7	1997	no
Loma Alta	38	1997	Maule, Invernada
San Ignacio	37	1996	Colbún
Capullo	10.7	1995	no
Aconcagua	72.9	1993	no
Curillinque	85	1993	Maule, Invernada
Alfalfal	160	1991	no

Table 6 - List of run of river plants constructed over the last 25 years
Source: SIC

Sub-step 4b. Discuss any similar options that are occurring:

Large Run of River hydroelectric projects that are not connected to reservoir facilities are rare within the project boundary, SIC. La Higuera will be the second biggest run of river project ever built by installed capacity in Chile[4]. In 1991 the 160 MW Alfalfal plant was built on the Colorado River, some 80km north of the La Higuera project. This project is similar in many ways to La Higuera project, however, the economics of the Alfalfal project were significantly better for two main reasons. Firstly, in 1991 there was no gas available, and as such node prices for energy were significantly higher than current prices. The second factor is that the owners, GENER, also have coal fired thermal plants, allowing them to mitigate the high seasonal generation of low winter generation and high summer snow melt generation.

Following the introduction of imported natural gas from Argentina in 1996 there was significant change in the electricity sector's structure, with high growth in the lower capital cost and shorter payback period combined cycle natural gas plants as shown in Figure 3. This resulted in a significant reduction in node prices. This has increased the barriers to hydroelectricity and other renewable energy technologies, which are typically much higher capital cost investments.

Step 5. Impact of CDM registration

[4] This does not include run of river plants associated with large reservoirs, which provide annual regulation, and as such should not be considered as run of river projects.

This section clearly explains how the approval and registration of the project as a CDM activity, and the attendant benefits and incentives derived from the project activity, will alleviate the barriers showed in Step 3 and thus enable the project to be undertaken. The benefits and incentives brought about by the CDM to the shareholders of the proposed project activity are as follows:

- The financial benefit from the revenue obtained by selling the CO_2 emissions reductions has been one of the key issues that encourage shareholders in the Project company to invest in the proposed project activity. The CDM has been considered from an early stage and it is an integral part of the financial package of the proposed project activity.

- Attracting new players who bring the capacity to implement a new technology. In this case, Pacific Hydro Ltd., an Australian company, and SNPI, a Norwegian company, are both entering a new market. The value of the CDM registration of investments is an important factor in attracting such world leading companies to Chile, bringing capacity and technology.

Therefore, it has been clearly demonstrated how the approval and registration of the project as a CDM activity, and the attendant benefits and incentives derived from the project activity, will alleviate the barriers showed in Step 3 and thus enable the project to be undertaken.

So following all steps of the additionality test, it can be clearly demonstrated that the proposed CDM project activity is not the baseline scenario.

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

>>

Chile has four different grids and there are no interconnections between them. Therefore each grid defines the geographical and system boundaries for proposed projects located within it (see map below).

The Central Interconnected Grid (SIC), to which La Higuera project is connected, compromises the regions 3 to 10 and accounts 64 percent of the total capacity. The project boundary of La Higuera project is the hydroelectric plant and all power plants connected physically to the SIC grid. The SIC grid electricity system's boundary is limited to the spatial extent of the power plants connected to the SIC grid, that can be dispatched without significant constraints. The following diagrams illustrate the location and spatial extent of the SIC grid.

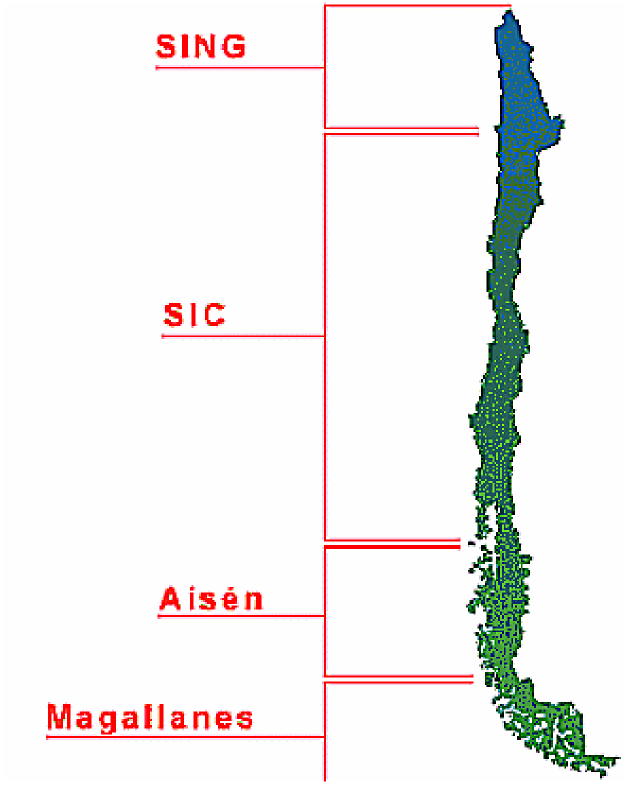

Figure 5 - Chilean Grid Systems

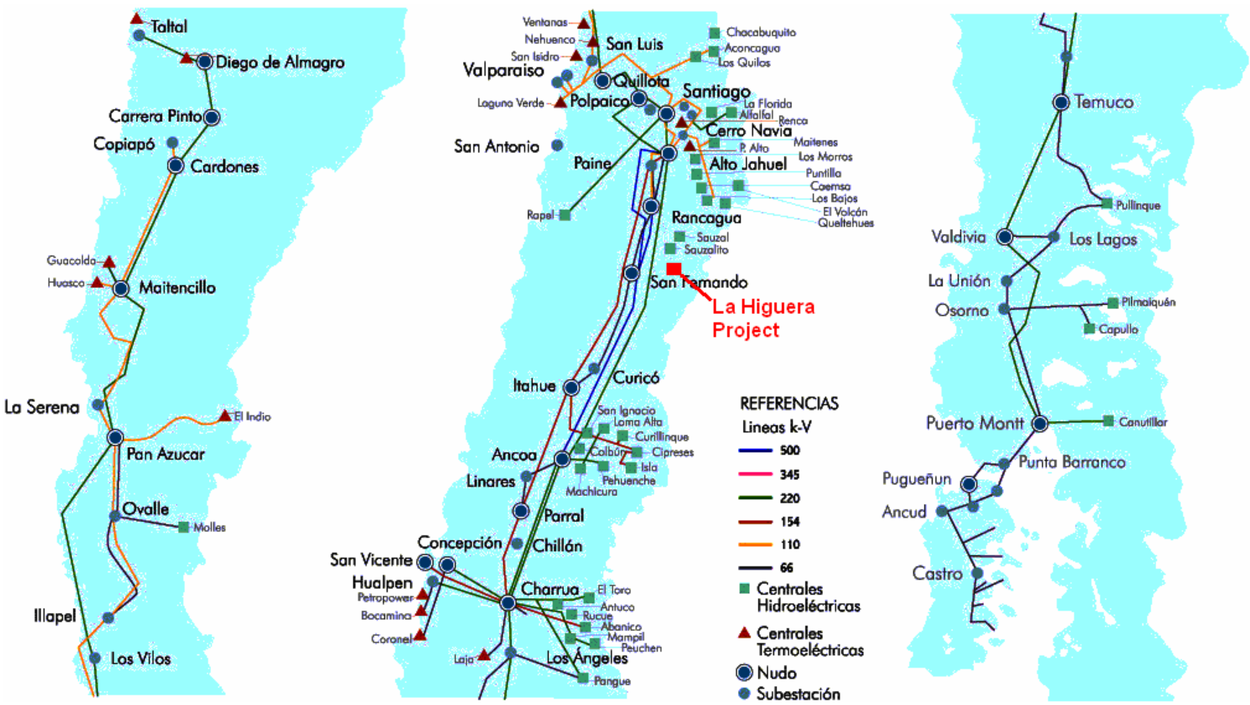

Figure 6 - The SIC System

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

>>

The baseline study was completed on 15/06/2005. The entity determining the baseline as the Carbon Advisor is EcoSecurities Ltd., UK. The Dispatch Data Analysis Model has been developed by Synex, S.A. in Chile.

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SECTION C. Duration of the project activity / Crediting period

C.1 Duration of the project activity:

C.1.1. Starting date of the project activity:

>>

Project development commenced in January 2002 when Pacific Hydro purchased on Option to Purchase the Water rights for the Tinguiririca Valley. Project Construction is expected to commence in the first quarter of 2006 and the project is to be connected to the grid and generating by January 2008.

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

>>

25 years, 0 Months

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

The project will use a renewable crediting period

C.2.1. Renewable crediting period

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

>>

Expected 01/01/2008 (if registration has been completed)

C.2.1.2. Length of the first crediting period:

>>

7 years

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

>>

Not applicable

C.2.2.2. Length:

>>

Not applicable

SECTION D. Application of a monitoring methodology and plan

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

>>

Approved consolidated monitoring methodology ACM0002: "Consolidated monitoring methodology for zero-emissions grid-connected electricity generation from renewable sources."

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

>>

The project activity is a grid-connected run of river hydropower project, where the grid's geography and system boundaries are explicit and characteristics are available through CNE and CDEC-SIC. On this basis the conditions for applying ACM0002 are met.

D.2. 1. Option 1: Monitoring of the emissions in the project scenario and the baseline scenario

D.2.1.1. Data to be collected in order to monitor emissions from the project activity, and how this data will be archived:								
ID number *(Please use numbers to ease cross-referencing to D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

Not applicable

D.2.1.2. Description of formulae used to estimate project emissions (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

>>

As the Project is a renewable source generation activity Project emissions are zero.

D.2.1.3. Relevant data necessary for determining the baseline of anthropogenic emissions by sources of GHGs within the project boundary and how such data will be collected and archived :								
ID number *(Please use numbers to ease cross-referencing to table D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e),	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
1. EG_y	Generation of the Project	Metering system	MWh	m	Hourly Measurement and daily recording	100%	electronic	Electricity supplied to the grid by the Project.
2. $EF_{OM, Dispatch\ Data ,y}$	Emission Factor of the grid for each hour Dispatch data, merit order and EF for every power plant in the grid		tCO_2/GWh	c	Hourly	100%	electronic	
3. $E_{OM,y}$	Emissions for operating margin	Dispatch data calculations	tCO_2	c	yearly	100%	electronic	
4. EF_{BM}	Build Margin Emissions factor for the grid	CDEC-SIC	tCO_2/GWh	c	At the beginning of each crediting period	100%	electronic	
5. EG_h	Hourly generation of the Project	Metering system	MWh	m	Hourly measurement and daily recording	100%	electronic	
6. $EF_{DD, h}$	Hourly generation –weighted average emissions per electricity unit of the set of power plants in the top 10% of grid dispatch order	CDEC-SIC Dispatch data calculations	tCO_2 /MWh	c	Hourly measurement and daily recording	100%	electronic	

7. $F_{i, n, h}$	Hourly amount of fuel consumed by *n* plants	CNE	tonnes	m	hourly	100%	electronic	
8. $COEF_{i, n}$	CO_2 emission factor of each plant by fuel type used	GHG Assesment Handbook[5]	tCO_2 /TJ	e	yearly	100%	electronic	
9. NCV_i	Net calorific fuel value per mass or volume unit of a fuel *i*	Node Price Fixation Report by CNE[6]	TJ/tonne	e	yearly	100%	electronic	
10. $OXID_i$	Oxidation factor of the fuel	GHG Assesment Handbook[7]	%	e	yearly	100%	electronic	
11. $GEN_{n, h}$	Hourly generation of electricity delivered to the grid by *n* plants	CDEC-SIC	MWh	n	hourly	100%	electronic	
12.	Merit order	CDEC-SIC	text	c	hourly	100%	electronic	
13. EF_y	Emission Factor of the grid in relation to the specific project activity	CDEC-SIC Dispatch data calculations	tCO2/MWh	c	yearly	100%	electronic	Calculated as weighted sum of the OM and the BM

D.2.1.4. Description of formulae used to estimate baseline emissions (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

>>
See Section B.2. for formulae.

[5] Exhibit 3-6, p. 28, GHG Assesment Handbook (figures are the same as those used in the IPCC 1996 Guidelines)

[6] Comision Nacional de Energia, Chile

[7] Exhibit 3-7, p. 29, GHG Assesment Handbook (figures are the same as those used in the IPCC 1996 Guidelines)

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

Not applicable

D.2.2.1. Data to be collected in order to monitor emissions from the project activity, and how this data will be archived:

ID number *(Please use numbers to ease cross-referencing to table D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e),	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

D.2.2.2. Description of formulae used to calculate project emissions (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.):

>>

Not applicable

D.2.3. Treatment of leakage in the monitoring plan

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

ID number *(Please use numbers to ease cross-referencing to table D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

Not Applicable

D.2.3.2. Description of formulae used to estimate leakage (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

>>
Not applicable

D.2.4. Description of formulae used to estimate emission reductions for the project activity (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

>>
As described in Section B.

D.3. Quality control (QC) and quality assurance (QA) procedures are being undertaken for data monitored		
Data *(Indicate table and ID number e.g. 3.-1.; 3.2.)*	Uncertainty level of data (High/Medium/Low)	Explain QA/QC procedures planned for these data, or why such procedures are not necessary.
1. EG_h	*Low*	EIH is monitored continuously. These data will be directly used for calculation of emission reductions. Sales record to the grid and other records are used to ensure the consistency.
12.Merit order	*Low*	Merit order is tracked by Government Authorities and it is publicly available.
Others 2-11, 13	*Low*	Default data (for emission factors) and IEA statistics[8] (for energy data) are used to check the local data.

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

>>
No leakage was identified for this Project activity.

[8] World Energy Outlook 2004 (IEA, 2004)

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

>>
The monitoring study was concluded in March 2005. The entity determining the baseline as the Carbon Advisor is EcoSecurities Ltd., UK. The Dispatch Data Analysis Model has been developed by Synex, S.A. in Chile. Contact details as listed in section B.5.

SECTION E. Estimation of GHG emissions by sources

E.1. Estimate of GHG emissions by sources:

>>

As a run of river hydro electricity project no GHG emissions are produced

E.2. Estimated leakage:

>>

No leakage was identified

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

>>

Zero

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

>>

Electricity Generated Emissions Reductions	Per Year	Crediting Period (7 years)
Estimated Dispatch Data Analysis Operating Margin Emissions Factor (EF_OM_y in tCO_2/MWh)	0.817	-
Build Margin Emissions Factor (EF_BM_y in tCO_2/MWh)	0.361	-
Baseline Emissions Factor (EF_y in tCO_2/MWh)	0.589	-
Electricity generated by Project (*EG* MWh)	811,000	5,677,000
Baseline Emissions (*BE* tCO_2)	**477,586**	**3,343,102**

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

Given that E.3 is equal to zero, the emission reductions of project activity are equal to E.4.

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

Year	Estimation of project activity emissions (tonnes of CO_2 e)	Estimation of baseline emissions (tonnes of CO_2 e)	Estimation of leakage (tonnes of CO_2 e)	Estimation of emission reductions (tonnes of CO_2 e)
Year 2008	0	**477,586**	0	**477,586**
Year 2009	0	**477,586**	0	**477,586**
Year 2010	0	**477,586**	0	**477,586**
Year 2011	0	**477,586**	0	**477,586**
Year 2012	0	**477,586**	0	**477,586**
Year 2013	0	**477,586**	0	**477,586**
Year 2014	0	**477,586**	0	**477,586**
Total (tonnes of CO_2 e)	0	**3,343,102**	0	**3,343,102**

Table 6 - Estimation of emissions during the project activity

SECTION F. Environmental impacts

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

>>
The project complies with the specific applicable regulations of the host country in regard to Environment Impact Assessment (EIA). The EIA follows the regulations for EIA System set in Chile by the Supreme Decree N 30/97 of the Ministry General Secretariat of the Presidency, Regulation for the Environmental Impact Assessment System and its modifications set in Supreme Decree N 95/2001, and the Act N 19300 on the Environmental Framework. The EIA has also passed the IFC regulations for EIA, one of the highest standards in the world. La Higuera has received the environmental permit issued by the Chilean government and the approval on environmental matter from the IFC.

The EIA discusses a wide range of environmental impacts related to physical, biotic, human, cultural, patrimonial and landscapes impacts during the plant's construction and operation stages. It identifies the risk or contingency zones and the type of risk associated to them. It also discusses a number of corrective measures and establishes an environmental management plan to deal with the impacts identified. This plan addresses the significant and medium impacts providing measures for their mitigation, restoration or compensation.

There are twelve positive impacts identified with effects on the human environment and the social-economic development of the District of San Fernando, where the project is located. The project will allow the generation of clean energy for the region displacing electricity generated from fuel-based power plants. Furthermore, it is going to generate benefits in the form of climate change mitigation.

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

>>
During the construction and operation stage, the only significant impact it is related to the loss of habitat for the aquatic fauna and flora. The environmental management plan establishes the measures undertaken to mitigate or compensate the impact. Furthermore, four medium impacts were identified and mitigation measures will be implemented in order to avoid any erosive process and alteration of the landscape after the construction stage.

SECTION G. Stakeholders' comments

>>

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

>>

According to the Chilean Environmental Law, a project of the size and characteristics of La Higuera is required to develop an Environmental Impact Study (EIS). La Higuera carried out the EIS between December 2001 and December 2003, with the obligation to carry public community consultations through publications in local newspapers and public hearings at a community level.

The public hearings were done with the local authorities and the local community. More than 100 people attended the presentation. Many of them were representatives of local interested groups. Both events took place in San Fernando, VI Region, in March 16, 2004.

1. Local authorities: More than 15 different authorities were present, including all relevant services dealing with the environmental and sectoral authorizations of the project . The presentation was done in 2 steps. One related to the technical and environmental aspect of the project and the second one related to the CDM characteristics of the project.

2. Local community: in accordance with the EIS procedure, the community was invited by the environmental authorities at a gathering, in which the project developer would present the major characteristics of the project.

G.2. Summary of the comments received:

>>

Local authorities: Questions were raised related to the road conditions and how the project would benefit the community. With respect to more work places and environmental conditions, all comments were positive, recognizing the benefits for the community of the project and the low impact on the environment.
With respect to the CDM aspect of the presentation, the authorities present showed a lot of interest, asking for more details related to this topic, especially with respect to the procedures and applicability conditions.

Local community: With respect to the technical and environmental aspects of the presentation, similar questions and comments were raised, as in the previous presentation. In relation to the CDM aspects, not big interested was shown by the audience, except for one question that questioned the emission reduction of the project by emphasizing that regardless of this project, no future thermal plants are going to be displaced due to the constant increase in energy needs.

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

>>

Although no major issues were raised that could be related to the environmental or CDM aspect of the project, all comments and questions were duly taken into account by the project developer. The main concern of the community was related to the improvements of roads, concern that the project developer resolved by a private agreement with the local authorities. All other technical and environmental aspects were resolved at the EIS and approved by the environmental authorities.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	HIdroelectrica La Higuera S.A.
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Represented by:	
Title:	Project Development Manager
Salutation:	Mr.
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Annex 2

INFORMATION REGARDING PUBLIC FUNDING

There is no public funding used in this project.

Annex 3

BASELINE INFORMATION
BUILD MARGIN CALCULATIONS FOR LA HIGUERA HYDRO

From the ACM0002 the build margin calculation is defined as:

Option 1. Calculate the Build Margin emission factor EFBM,y ex ante based on the most recent information available on plants already built for sample group m at the time of PDD submission. The sample group m consists of either:

- *the five power plants that have been built most recently, or*
- *the power plants capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently.*

Project participants should use from these two options that sample group that comprises the larger annual generation.

In the SIC network, 20% of annual generation is approximately 7,000,000MWh. Using the above methodology the build margin will be calculated using the most recent available data for the past 12 months (Dec 2003 to November 2004) and estimation of annual energy generation where complete data is not yet available. The results for this calculation are shown in the table below.

Plant	Year	Fuel Type	2004 Energy Generated (MWh)	Annual CO_2 Emissions (tonnes)
Licanten	2004	Biomass	21,391	0
Valdivia	2004	Biomass	155,707	0
Antilhue TG	2004	Diesel	870	3180.104
Horcones TG	2004	Diesel	12,078	45475.49
TG Coronel	2004	Diesel	0	0
Itata	2004	Biomass	0	0
Ralco	2004	Hydro	1,332,259	0
Nehuenco II	2003	CCGT	1,996,332	736178.5
Cholguan	2003	Biomass	93,234	0
Nehuenco 9B Diesel	2002	Diesel	39,223	31801.04
Nehuenco 9B CCGT	2002	CCGT	68,377	43170.96
SF de Mostazal	2002	Diesel	9,380	9219.121
Chacabuquito	2002	Hydro	152,945	0
Taltal 2 Diesel	2000	Diesel	59	50.88166
Taltal 2 OCGT	2000	OCGT	364,308	244256.8
Taltal 1	2000	OCGT	624,493	418758.3
Peuchen	2000	Hydro	262,257	0
Mampil	2000	Hydro	174,152	0
Petropower	1998	Coal	526,232	474286.1
Nehuenco Diesel	1998	Diesel	47,800	24486.8
Nehuenco	1998	CCGT	1,800,051	740268.4
Totals			7,681,148	2,771,133

Build Margin	**0.361**

Table 7 - Data used to calculate the build margin

Annex 4

MONITORING PLAN

As described in Section D.