PONTIFICIA UNIVERSIDAD CATOLICA DE CHILE
ESCUELA DE INGENIERIA

HYDROLOGICAL RISK ALLOCATION AND ITS INFLUENCE OVER LONG TERM CONTRACTING IN THE CHILEAN ELECTRICITY SYSTEM

CRISTOBAL ALBERTO SARQUIS GIACAMAN

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

Advisor:
HUGH RUDNICK VAN DE WYNGARD

Santiago de Chile, (August, 2014)

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A todos quienes formal o tácitamente forman parte de este estudio, para el que mi nombre es meramente un medio.

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RESUMEN

El riesgo hidrológico es un riesgo sistémico, y como tal, afecta a todas las partes interesadas de un mercado eléctrico como el Sistema Interconectado Central (SIC), cuyos precios spot se ven altamente influenciados por la generación hidroeléctrica. Los contratos de energía de largo plazo son atractivos para los generadores y para sus clientes, pero cubrirse ante los riesgos es un desafío para ambos. El nivel de contratación para generadores debe responder a restricciones físicas de energía generada esperada en cualquier hidrología, tomando en cuenta incertidumbres de largo plazo. Para clientes debe considerar tanto incertidumbre en las proyecciones de demanda, como responder al compromiso que enfrentan entre variabilidad del costo de suministro y costo de la energía. En ese sentido, hay una cantidad optima de energía asociada a contratos bilaterales futuros que está intimamente relacionada con las condiciones específicas de cada mercado eléctrico. Este estudio considera el impacto del riesgo hidrológico sobre la contratación óptima del sistema y evalúa la posición óptima de contratación del SIC bajo la premisa que los generadores, aversos al riesgo, buscan minimizar la varianza de su margen comercial como política de cobertura. La existencia de una asignación incorrecta de riesgo hidrológico en la regulación chilena motiva este estudio, que revela que, aunque se pueda cubrir perfectamente cualquier riesgo, y se desarrolle una expansión óptima en nueva capacidad, no existen incentivos adecuados que aseguren la contratación de toda la demanda a precio fijo sin mecanismos de compartición de riesgo hidrológico entre las partes interesadas. La expansión óptima se evalúa minimizando los costos de operación e inversión del sistema en un horizonte de 10 años.

Palabras clave: licitaciones de energía, gestión del riesgo, coberturas hidrológicas, contratos de suministro de energía.

ABSTRACT

Hydrological risk is systemic, and as so, affects every stakeholder in an electrical marker like the SIC, whose generation prices are highly influenced by hydroelectric generation. Energy long-term contracts are attractive for generators and for clients, but hedging is challenging for both. The hedging level for generators must respond to physical constraints of expected energy supply in any hydrological scenario, taking long-term uncertainties into account. For clients it must address uncertainty on demand projections and respond to the tradeoff between variability and cost of energy procurement. In this sense, there is an optimal forward quantity of energy of bilateral contracts intimately related with specific market conditions. This study assesses the optimal contracting position of the SIC under a framework where risk-averse generators pursue minimal variability in their commercial margins as a criterion of hedging, only assessing the hydrological risk impact over optimal contracting of the system. It is motivated by the existence of an incorrect hydrological risk allocation scheme in Chilean regulation. The study reveals that, even given an optimal expansion in new capacity and a perfect hedge of every risk factor, proper incentives do not exist that allow a full demand contracting at a fixed price in the absence of hydrological risk sharing mechanisms among actors. In order to assess the system's optimal expansion, a minimization of the total discounted costs of investment, operation and maintenance of the system, given a ten-year span, is performed.

Keywords: energy auctions, risk management, hydrological hedging, electricity supply contracts.

1 INTRODUCTION

The central interconnected system (known by its acronym SIC in Spanish) is the largest electrical system in Chile, geographically encompassing the majority of the country's territory and supplying nearly 90% of its population. Generation companies (Gencos) coordinate through an Independent System Operator (known by its acronym CDEC in Spanish), and as a result, the decision of timing or of the amount of generation does not depend on Gencos but rather on minimal operation cost conditions subject to supply security considerations[1]. Because nearly 45% of the SIC installed capacity is currently based on run-of-river and dam power plants, the SIC is considered a mixed hydrothermal system. As a result, one of the main sources of spot price volatility present in this system stems from hydroelectric uncertainty. Fuel prices are also important drivers on spot price variations, but proper mitigation possibilities exist and are considered in regulation. According to risk categorization in energy contracts as presented in Wiser, R. et al., 2003, hydrological risk is a systemic risk that affects every stakeholder, and whose allocation influences Gencos' investment decisions, thereby impacting both the type of power plants that are built and the system's electricity supply portfolio.

[1] In order to maximize the welfare of the community as described by Bernstein, 1988, the Chilean electricity sector was pioneer in introducing competitiveness in the power sector by privatizing it, allowing competition amongst generation companies (Gencos) and setting up a new marginal cost and spot pricing system. As described by Schweppe et al. 1988, short-term energy spot prices give signals to promote the interest of investors in building efficient capacity on an optimal mix according to system needs. As a result, investors recover total investment and operation costs. The spot prices, accordingly, give reason to the spot market where only Gencos can trade their instantaneous differences between energy committed to be supplied and energy effectively generated by reason of the economic dispatch driven by CDEC

Gencos can determine contracting strategies by deciding how much energy to sell in a volatile spot market and which level of hedging to assume, therefore selling part of their energy at a more stable price stipulated in long term contracts (LTC, commonly called power purchase agreements). This hedging level must be carefully decided, considering how much energy can be produced by each Gencos' power plant. A Genco compromising more energy than that which it can physically generate, could make it buy energy in the spot market, exposing it to volatile spot pricing. According to Street et al., 2009, long-term bilateral contracts represent a challenge for Gencos in that they must take into account long-term uncertainties.

According to Guzman et al., 2011, the contracts market has the objective of reflecting long-run price expectations. Stable and efficient prices are also of the interest to clients, who face a tradeoff between stability and efficiency in prices. Stability means hedging from uncertainty in production costs, mainly stemming from hydrological conditions. These incentives raise a systemic risk allocation problem that affects every generator and client: how much energy Gencos are willing to deliver at stabilized prices and customers willing to pay for? How much energy is to be sold with some mechanism of risk sharing, so that the selling price reflects the changes in production costs? To be solved, this risk allocation problem needs to have previously answered to the question about the optimal amount of energy that a system, aiming to minimize its margin's variability, is willing to commit at fixed prices[2].

[2] The term "fixed price" captures the impossibility of sharing hydrological risk with customers or Discos. A "fixed price" contract should only index the sale price of energy to fuel prices and CPI, but should not index to hydrological conditions for example like rainfall or steamflows.

In the case of Chile, Gencos have two possible clients for LTCs: large industrial consumptions (over 2 MW, called "free clients"), which freely negotiate the price of energy through private contracts with Gencos, and regulated customers supplied by distribution companies, whose price is determined by public and competitive auction processes governed by the authority.

Since the introduction of "Ley Corta II" (law n° 20.018 established in 2005), distribution companies (Discos) must support their entire demand through auctioned long term contracts (LTC) with Gencos, where the energy price can be indexed to the Consumer's Price Index (CPI) and fuel prices. The auctions consider a price-cap decided by the National Energy Commission, over which the bids are not admissible. On the other hand, free clients can handle bilateral private contracts directly with Gencos, as opposed to standardized contracts. Therefore, free clients can procure energy on LTCs with the ability to allocate hydrological risk according to risk aversion profiles. Since the spot market is only conceived for the Gencos, all of the demand, in its entirety, must be supported by supply contracts.

The auction approach was introduced in order to establish a method that would both stimulate supply development on the one hand, and provide economic certainty to investors on the other. It aimed to provide regulated clients with efficient long-term prices given by the cost of development of the system. Nevertheless, Moreno et al., 2012 argue that the auction method has not achieved the prior objectives. Moreover, not only has there been progressively less interest in participating in auctions, but the last seven auctions were declared partially deserted given that Gencos simply were not able or willing to provide energy, not even at the bid price-cap determined by the authorities. There are some that argue that a deficit on base-load capacity and a recent period of droughts have resulted in difficulties regarding these auctions[3]. Consequence of these difficulties is that distribution companies that no longer have contracts for a portion of their demand[4] are unable to assure supply to their clients. Even though according to Street et al., 2009, open LTC auctions were designed in Brazil and Chile to allocate risks between Discos, Gencos and consumers, in order to promote efficient purchases, the scheme in Chile does not really consider a proper risk allocation mechanism. The way the current system is designed provides regulated clients with zero hydrological risk exposure, while fully exposing other industrial customers and Gencos to the aforementioned systemic risk, by means of spot market participation.

Recently, there have been various studies regarding Chilean auction processes. These studies have analyzed the difficulties related to the design of these auctions, and have somehow predicted these difficulties as well as others. Roubik et al., 2008 argue that Gencos decide upon their contracting offers by performing strategy games and thus considering risk adversity in their portfolio preferences. Moreno et al., 2010 consider efficiency and risk transfers as relevant concepts, and propose modifications to the design of auctions implemented in Chile. Finally, Moreno et al., 2012 explain that for any given installed capacity, if a Genco situates itself at a contracting level other than its optimal positioning given its capacity, that Genco will immediately seek to celebrate higher price contracts. Seeking higher price contracts will invariably result from the decision to supply

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[3] Bernstein et al., 2013, argues that a lack of base energy has not been driven by underinvestment decision or absence of competitiveness among Gencos, but because of judicialization of projects, a situation with still bad perspectives.

[4] Assuring supply to regulated clients is a Disco's mandatory obligation according to delegated legislation DFL 4 on its 131 article

at different contracting capacities given the additional risk that these generators must assume in order to supply at these aforementioned levels. As a result, contracting at levels other than their optimal positioning leads to less competition in an environment where generators have already committed much of their present capacity and where the prospects of a new base-load energy entering the market are bleak given the increased judicialization of projects. Moreno et al., 2012 conclude that, for regulated supplies, the authority should clearly identify the proper amount of risk allocated to clients and/or to Gencos. This work is motivated by a pursue of a better understanding of a system's efficient risk allocation, which considers the heterogeneous desirability of each technology according to the variability of their generation imposed by hydrologies, to commit part of their firm's energy[5] on long term contracting. In consequence, it tries to answer how the installed capacity and technological mix of the system determines the total system's optimal desirability of fixed price contracting positions. According to Street et al., 2009, the optimal forward consumption of bilateral contracts is intimately related to the specific characteristics of each market.

Optimal hedging positions have been studied, on bid-based markets, in order to define both how much capacity to put into the futures market, and how much to keep in order to bid in the spot market[6]. However, the Chilean dispatch system is audited as a cost-based and not

[5] Firm energy is the amount of energy guaranteed available with high certainty, taking into account maintenance periods and forced unavailability. Solar and wind generation in this study considers average availability of the renewable source, therefore its actual generation variability is not captured.

[6] Guan et al., 2006, focuses on the generation portfolio management between monthly future markets and daily spot markets, based both on the current forward price and the forecasted hourly spot prices. They minimize the risk-adjusted variance of the total profit function under a mean-variance scheme. Conejo et al., 2008 also provides a procedure suitable to determine the optimal involvement in the forwards market by a power producer, under a CVaR methodology. Forward contracting decisions are made at the beginning of

bid-based approach. As a result, the the source of volatility is different, given that in Chile, it proceeds from hydroelectric availability rather than energy bids.

Street et al., 2009, studied bidding strategies in LTC auctions by Gencos on hydrothermal cost-based systems, pursuing to achieve an optimal combination of risk and return (operational net revenue), according to Gencos' risk aversion profile. Their goal was to assess an optimal Willing-to-supply curve, which determines the amount of Firm Energy Certificates (FEC) to commit to contracts given their selling prices. Studying the case of Brazil, Street et al., 2009 concluded that a risk averse CVaR based agent, owner of a hydroelectric power plant, would never commit 100% of its FEC on LTC, due to the negative correlation between spot prices and system production. Finally, Näsäkkälä & Keppo, 2005 stated that, when minimizing the portfolio variance of a flexible producer, if its expected generation and the spot prices are negatively correlated, it is optimal to under hedge in relation to expected generation. In that sense, and because negative correlation is a natural hedge against price changes, a flexible producer should commit less energy in forward contracts than what it expects to generate.

Street's work has a similar intent and approach to that of the present analysis[7]. This analysis assesses the total amount of energy that the SIC's Gencos desire to commit on LTC (either with free consumers or with Discos), and considers the SIC's Gencos' tendency to be risk averse, and so assume minimum risk decisions. For this purpose, it minimizes the variability of the commercial margin of the system as a criterion of hedging,

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each month affecting the following 12 months, while decisions pertaining to the pool are performed within the year on a day-ahead scheme.

[7] Nevertheless, this study does not pretend to predict final bidding strategies according to agent's profiles or financial situations.

composed by both an injections margin (because of generation contribution to the system) and a contracts margin (because of sales). It reveals that in a system like the SIC, where there is an important component of hydroelectric generation, there are no proper incentives that allow for full demand contracting at a fixed price, without hydrological risk sharing among actors, even if there is an optimal expansion in new capacity. This result considers only the hydrological uncertainty, which is one of the main risk factors in a hydrothermal electricity system, and also one of the most important drivers on spot price and generation costs.

This study concludes that the lack of base-load investments is not the only difficulty facing the unwillingness to bid on Chilean auctions. Even if every investment was efficiently performed, the practice of risk-averse Gencos to contract at a fixed price, without hydrological risk sharing, still does not align with the demand.

Under current regulation, risk allocation possibilities mean that only Gencos and free clients are assuming hydrological risk, while regulated clients remain under an arbitrary shield. The present work helps on realizing that a scheme where the whole demand is contracted at fixed prices implies a more risky situation for Gencos than the optimal contracting position calculated, that implies minimum variance. This way, the Chilean Gencos may be transferring this extra risk compared to the optimal contracting position by means of a risk-premium in the energy price. This risk-premium complemented with a lack of base-load investments and a price-cap that does not consider the premium, should be the causes of the unwillingness to bid on energy auctions. Higher price-caps on auctions should overcome this unwillingness, but it would probably mean a price signal unaligned with consumers' risk aversion profiles. Chilean regulation has not yet considered the existence of optimal spot price exposure for consumers who face not only a tradeoff between risk and cost, but also the uncertainty on demand projections. Gedra 1994 and Woo et al., 2004 have also studied different approaches regarding Discos' optimal involvement on behalf of consumers related to forward purchasing in other markets. Would it be better for regulated clients to pay the risk-premium or to share the hydrological risk with Gencos?

If the intent of the authority remains to maintain full demand contracting without hydrological risk sharing, it would then be necessary to adopt higher energy procurement prices in order to avoid deserted auctions. It would be interesting to design a more efficient risk allocation scheme than the current one, which is rigid and forces allocation of hydrological risk among stakeholders. Every market experiences natural deviations of optimal efficient situations and/or inaccurate projections. The market design should consider the possibility of correctly adjusting to these deviations, especially given the electrical markets characteristics, where new offer investments takes several years to become established.

2 METHODOLOGY

This section describes the two models developed to estimate and project the amount of energy suitable to be committed on LTC for the totality of a system like the Chilean SIC. The models also assess how the amount of this energy that is committed is done so without hydrological risk sharing mechanisms. The first model determines the optimal system expansion that a benevolent social planner would perform given efficiency through minimal operational and investment costs, where every MW of each technology installed, is profitable. The second model estimates the adequate amount of energy suitable to be committed on LTC, taking into consideration risk-averse Gencos.

2.1 Optimal system's expansion through efficient investments, taking into account investment constraints

The model considers the minimization of the system's discounted operation and investment costs, taking into account levelized costs of technologies available in Chile and their evolution in time. The model also considers hydroelectric generation as a random variable chosen from equiprobable historical statistics of hydrologies, but it does not optimizes reservoir's generation. A single node for both consumption and generation is considered, so no transmission constraints were considered since they have no relation with hydrological risk. The hydroelectric power plants are modeled capturing the particularities of both different geographical locations (different basin characteristics), and different regulation capacity (different response and peak demand contribution). The demand is modeled with 9 different blocks that fit the duration curve of the SIC[8]. The optimal expansion of the system is solved endogenously for the period 2013 to 2022, taking into consideration the operation and investment costs faced by each technology, so not assuming a previous plan of investments given by available projects, but deciding efficient investments by minimizing total system's costs. In that sense, this model does not pretend to predict the eventual evolution of the system investments. Instead, the model seeks to obtain a possible efficient expansion of the system, implying more generous investments than the market's actual suboptimal projections.

The base model considers the SIC's 2013 installed capacity. It models non-hydroelectric power plants as an aggregated large single plant by technology (coal, wind, etc). Each of the actual hydroelectric power plants that exist in the Chilean system is represented individually, with their different availability depending on the hydrological conditions. Also, for the following simulated years, the power plants already under construction are considered with a fixed commissioning date. The model has a simplified representation of non-conventional renewable energies (NCRE)[9] as it does not take into account their stochastic availability and other constraints that may limit their participation in the system. For this reason, up and coming non-conventional renewable energy power plants are considered as an input data according to the projections of the National Energy

[8] The demand blocks (MWs and hours per block) are established minimizing the mean quadratic error between them and the real duration curve of the system.

[9] Non-conventional renewable energy in Chile is considered all renewable energy such as wind, solar, biomass, geothermal and hydroelectric plants under 20 MW.

Commission[10] (known by its acronym CNE in Spanish). NCRE's expansions are fixed exogenously according to the authority's projections for simplicity, given that in Chile they respond to a special promotion law. For each new project, and depending on each technology, there is a different pre-engineering, engineering, bureaucracy and construction period. As a result, and for example, new coal-based plants are unable to be operating at least until 2018. Finally, the model takes into account the possibility of investing in regasification facilities in order that these be able to operate CCGT with LNG instead of the diesel that is used nowadays.

2.1.1 The planning model

Sets:

$I: hydroelectric\ power\ plants$

$BL: demand\ blocks = \{block_1, \dots, block_9\}$

$H: hydrologies = \{h_1, h_2, \dots, h_{51}\}$

$NHT: non-hydroelectric\ technologies$

$$= \left\{ \begin{matrix} coal, diesel\ CCGT, diesel\ OCGT, LNG\ CCGT, diesel\ CCGT\ conv.\ to\ LNG^{11}, \\ wind, solar\ PV, geothermal, biomass, failure^{12} \end{matrix} \right\}$$

$EHPP: existing\ hydroelectric\ power\ plants = \{ehpp_1 \dots ehpp_i\}$

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[10] Projected in its April 2013 biannual report: ("Informe Técnico Definitivo Fijación de Precios de Nudo SIC"). Every six months, the National Energy Commission determines an indicative plan of investments for generation-transmission of both Chilean interconnected systems.

[11] The possibility of using LNG instead of diesel in Nehuenco and Nueva Renca requires the consideration of new artificial technology, given that new investment costs consider regasification units instead of gas turbines.

[12] Possibility of failure is modeled as an expensive thermal power plant

$POIHPP: \ hydroelectric\ power\ plants\ on\ CNE\ plan\ of\ investments = \{ehpp_1 \dots ehpp_i\}$

$T: years\ of\ analysis\ = \{2013, \dots ,2022\}$

Parameters:

$AHIC_i: adjusted\ hydroelectric\ investment\ costs$[13] $as\ an\ equivalent\ annuity\ \left[\frac{kUS\$}{MW - year}\right].$

$ANHIC_{nht}: adjusted\ non\ hydro. investment\ costs$[14] $as\ an\ equivalent\ annuity\ \left[\frac{kUS\$}{MW - year}\right]$

$HOC_i: hydroelectric\ power\ plant\ i\ operational\ costs\ \left[\frac{US\$}{MWh}\right]$

$NHOC_{nht}: non-hydroelectric\ technology\ nht\ operational\ costs\ \left[\frac{US\$}{MWh}\right]$

$DB_{bl}: duration\ of\ demand\ block\ bl\ [hours]$

$PB_{bl,t}: depth\ of\ demand\ block\ bl\ on\ year\ t\ [MW]$

$HA_{i,h}: availability\ of\ hydroelectric\ power\ plant\ i\ on\ hydrology\ h\ [\%]$

$HDF_{i,bl}: dispatch\ factor\ of\ hydroelectric\ power\ plant\ i\ on\ block\ bl\ [\%]$

$NHA_{nht}: availability\ of\ non-hydroelectric\ technology\ nth\ [\%]$

$HPPP_i: installed\ or\ installable\ capacity\ of\ hydroelectric\ power\ plant\ i\ [MW].$

$HPPA_{poihpp,t}: \begin{Bmatrix} 1 & hydroelectric\ power\ plant\ poihpp\ is\ available\ to\ operate\ on\ year\ t \\ 0 & it\ is\ not \end{Bmatrix}$

$SICIC_{nht}:\ SIC\ installed\ capacity\ on\ year\ 2013\ [MW].$

$r:\ Discount\ rate\ [\%].$

[13] Includes fixed yearly O&M costs
[14] Includes fixed yearly O&M costs and equivalent regasification terminal cost for CCGT LNG technology

Decision variables:

$HG_{h,i,bl,t}$: $MWh\ generated\ by\ hydroelectric\ power\ plant\ i, on\ bl\ of\ t\ and\ h$

$NHG_{h,nht,bl,t}$: $MWh\ generated\ by\ non-hydroelectric\ technology\ nht, on\ bl\ of\ t\ and\ h$

$$IHPP_{poihpp,t}: \begin{Bmatrix} 1 & hydroelectric\ power\ plant\ of\ plan\ of\ works\ is\ installed\ on\ year\ t \\ 0 & it\ is\ not \end{Bmatrix}$$

$NHP_{nht,t}$: $installed\ capacity\ of\ non-hydroelectric\ technology\ nht\ on\ year\ t\ [MW]$.

Objective Function:

$$\min Investment\ Cost + Operation\ Cost + Failure\ Cost$$

$$= \min \sum_{t=2013}^{2022} \frac{1}{(1+r)^t} \left[\sum_{poihpp=1}^{POIHPP} AHIC_{poihpp} \cdot HP_{poihpp} \cdot IHPP_{poihpp,t} + \sum_{nht=1}^{NHT} ANHIC_{nht} \cdot NHP_{nht,t} + \frac{\sum_{h=1}^{H} \left(\sum_{bl=1}^{BL} \left[\sum_{i=1}^{I} HOC_i \cdot HG_{h,i,bl,t} + \sum_{nht=1}^{NHT} NHOC_{nht} \cdot NHG_{h,nht,bl,t} \right] \right)}{10^3\, card(H)} \right]$$

Constraints:

(1) Generation supplies demand:

$$\sum_{i=1}^{I} HG_{h,i,bl,t} + \sum_{nht=1}^{NHT} NHG_{h,nht,bl,t} \geq PB_{bl,t} \cdot DB_{bl}$$

$$\forall bl \in BL, \forall h \in H\ y\ \forall t \in T$$

(2) Generation according to availability of hydroelectric power plants:

$$HG_{h,ehpp,bl,t} \leq HDF_{ehpp,bl} \cdot DB_{bl} \cdot HP_{ehpp} \cdot HA_{ehpp,h}$$

$$\forall bl \in BL, \forall ehpp \in EHPP, \forall h \in Hy\ \forall t \in T$$

$$HG_{h,poihpp,bl,t} \leq HDF_{poihpp,bl} \cdot DB_{bl} \cdot HP_{poihpp} \cdot HA_{poihpp,h} \cdot IHPP_{poihpp,t}$$

$$\forall bl \in BL, \forall poihpp \in POIHPP, \forall h \in H \ y \ \forall t \in T$$

(3) Generation according to availability of non-hydroelectric power plants:

$$NHG_{h,nht,bl,t} \leq NHA_{nht} \cdot NHP_{nht} \cdot DB_{bl}$$

$$\forall bl \in BL, \forall nht \in NHT, \forall h \in H \ y \ \forall t \in T$$

(4) Non-decreasing installed capacity:

$$IHPP_{poihpp,t} \leq IHPP_{poihpp,t+1}$$

$$\forall t \in \{2013, \ldots, T-1\}, \forall poihpp \in POIHPP$$

$$NHP_{nht,t} \leq NHP_{nht,t+1}$$

$$\forall t \in \{2013, \ldots, T-1\}, \forall nht \in NHT$$

(5) Hydroelectric power plants eventual startup according to plan of investments timings:

$$IHPP_{poihpp,t} \leq HPPA_{poihpp,t}$$

$$\forall t \in T, \forall poihpp \in POIHPP$$

(6) Non-hydroelectric installed capacity in year 2013:

$$NHP_{nht,2013} = SICIC_{nht}$$

$$\forall nht \in NHT$$

(7) Possibility to convert diesel CCGT to LNG CCGT[15]:

$$NHP_{diesel\ CCGT\ conv.to\ LNG,\ t+1} - NHP_{diesel\ CCGT\ conv.to\ LNG,\ t} = NHP_{diesel\ CCGT,t} - NHP_{diesel\ CCGT,t+1}$$

$$t \in \{2014, \ldots, T-1\}$$

[15] As of 2015, it will be possible to convert current Diesel CCGT to LNG CCGT turbines.

(8) Fixed variables: plants under construction with fixed commissioning date; NCRE's according to CNE's plan of investments[16]; and pre-commissioning lead-times[17].

(9) Non negativity and sets:

$$HG_{h,i,bl,t}, NHG_{h,nht,bl,t} \geq 0 \in R, \qquad \forall\, h, i, nht, bl, t$$

$$IHPP_{poihpp,t} \in \{0,1\}, \qquad \forall\, poihpp, t$$

$$NHP_{nht,t} \geq 0 \in R, \qquad \forall\, nht, t$$

The economic problem driven by the linear model is solved by CPLEX on GAMS, and it decides on the technology mix to expand the generation park each year of analysis. In consequence, it decides whether to include each of the hydroelectric projects individualized and considered by CNE's databases, and which capacity expansion to perform for each thermal technology. It also decides the eventual conversion of diesel CCGT power plants into LNG CCGT, considering the extra costs on regasification units needed to be performed for the conversion, and according to the timings of the CNE plan of investments.

Together with the investment decision, the algorithm performs an operational optimization for each of the 51 hydrological scenarios, and in consequence, there are 51 simplified economic dispatches for each one of the 9 demand blocks. The dispatch is simplified by the exclusion of the inter-annual capacity of water transferring of Laja Lake's dam. In that sense, the price of water is not computed, given that yearly each plant is modeled with both yearly inflow and yearly peak response capacities. As a result, there is independence on

[16] Biomass, geothermal, wind and PV solar projects

[17] Pre-commissioning lead-times are different for each technology. The earliest possible introduction of new capacity, if economically efficient is: 2018 for coal; 2017 for LNG CCTG, diesel OCTG and diesel CCTG

yearly water dispatches. The model previously described, considers each one of the 51 hydroelectric generation scenarios as equiprobable random variables. It determines the most economic investments for any hydrological condition effective on any given year within the 10-years optimization horizon. As a result, the model projects the spot prices of the system, which corresponds to the dual variable of the first constraint, without discounting cost of capital (10% according to Chilean law):

$$SP_{bl,h,t} = (1+r)^t \cdot Dual\{Generation\ supplies\ demand\}$$

2.2 An optimal contracting position considering risk aversion

The methodology involves the deliverance of energy obligations according to the demand fluctuations so following the duration curve (modeled in blocks). It calculates the yearly quantity of energy committed by a company on LTCs, with the purpose of hedging its exposure to the spot market as a risk-averse agent, and in consequence, minimizing the commercial margin's variability of the firm. The optimal contracting position is calculated for an artificial monopolistic firm owning the entire system capacity and for each one of the SIC's companies. It is also calculated by conceiving a fictitious company representing only the total installed capacity of each technology.

It is assumed that a company cannot exercise market power. A company's yearly ex-ante production function, according to Chavas & Pope, 1982 is denoted by:

$$\pi_t = MgI_t + MgC_t = \sum_{bl} MgI_{bl,t} + \sum_{bl} MgC_{bl,t} \tag{2.1}$$

$$\pi_t = \sum_{bl} Eg_{bl,t} \cdot \left(SP_{bl,t} - VC_t\right) + \sum_{bl} Ec_{bl,t} \cdot \left(PC_t - SP_{bl,t}\right) \tag{2.2}$$

$$\pi_t = \sum_{bl} Eg_{bl,t} \cdot \left(SP_{bl,t} - VC_t\right) + Ec_t \cdot (PC_t - WSP_t) \tag{2.3}$$

$$\pi_t = MgI_t + Ec_t \cdot WMgCuni_t \tag{2.4}$$

Where:

$MgI_t = energy\ injections\ margin\ on\ year\ t\ [US\$]$

$MgC_t = energy\ contracts\ margin\ on\ year\ t\ [US\$]$

$Eg_{bl,t} = energy\ generated\ on\ demand\ block\ bl\ [MWh]$

$Ec_{bl,t} = energy\ contracted\ on\ demand\ block\ bl\ [MWh]$

$SP_{bl,t} = spot\ price\ of\ system\ on\ demand\ block\ bl\ [{}^{US\$}/_{MWh}]$

$VC_t = variable\ cost\ of\ operation\ of\ power\ plant\ [{}^{US\$}/_{MWh}]$

$PC_t = energy\ price\ of\ the\ contracts\ [{}^{US\$}/_{MWh}]$

$WSP_t = wheighted\ spot\ price$

$$WSP_t = \sum_{bl} DF_{bl,t} \cdot SP_{bl,t} \tag{2.5}$$

$DF_{bl,t} = portion\ of\ energy\ commited\ on\ block\ bl\ over\ yearly\ commited\ energy$[18]

$$DF_{bl,t} = {}^{DB_{bl} \cdot PB_{bl}}/_{\sum_{bl} DB_{bl} \cdot PB_{bl}} \tag{2.6}$$

[18] This component lets the contracts to follow demand's shape

The evaluation yearly minimizes the margin's variance, thus an optimal hedge of hydroelectric risk is achieved:

$$\min \sigma_{\pi}^{2} = \min \sigma_{MgI}^{2} + Ec^{2} \cdot \sigma_{WMgCuni}^{2} + 2Ec \cdot \sigma_{MgI,Ec\cdot WMgCuni} \qquad (2.7)$$

$$\partial\sigma_{MgT}^{2} \Big/ \partial Ec = 0 = 2Ec \cdot \sigma_{WMgCuni}^{2} + 2 \cdot \sigma_{MgI,Ec\cdot WMgCuni} \qquad (2.8)$$

$$Ec^{*} = \sigma_{MgI,Ec\cdot WMgCuni} \Big/ \sigma_{WMgCuni}^{2} \qquad (2.9)$$

Now, given that:

$$\sigma_{MgI,Ec\cdot WMgCuni} = \mathbb{E}([MgI - \mathbb{E}(MgI)] \cdot [WMgCuni - \mathbb{E}(WMgCuni)])$$[19]

$$\sigma_{MgI,Ec\cdot WMgCuni} = \mathbb{E}\big(MgI \cdot (PC - WSP)\big) - \mathbb{E}(MgI)\mathbb{E}\big((PC - WSP)\big)$$

$$\sigma_{MgI,Ec\cdot WMgCuni} = \mathbb{E}(MgI) \cdot \mathbb{E}(WSP) - \mathbb{E}(MgI \cdot WSP)$$

$$\sigma_{MgI,Ec\cdot WMgCuni} = \sigma_{MgI,WSP} \qquad (2.10)$$

The equation 2.9 shows that the optimal contracting position does not rely on contracting price 'PC'. This is an important consideration for the upcoming analysis, given that it will not depend on the negotiation capacity on contracting, nor rely on a profits point of view. Instead, the discussion will depend only on hydrological risk considerations and a price-independent analysis will be performed. This methodology takes into account the decisions of risk-averse Gencos who, when celebrating forward contracts, protect these contracts

[19] $\mathbb{E}$(x) denotes the expected value of the random variable x

from pool price volatility. However, by assuming less risk, these risk-averse Gencos in turn expect lower returns. This methodology thus considers, and in accordance with Conejo et al., 2008, an increase in the power that risk-averse Gencos are willing to sell in the futures markets versus the power that risk-neutral agents would willingly supply to the same.

The independence between an optimal contracting position over the total firm energy of a company and the price of the eventual contracts is a fact aligned with a Value at Risk (VaR) decisions perspective. For any probabilistic distribution that a risk averse company's commercial margin may have depending on rainfall and snow melt conditions, a lower margin's variability over the same mean is reflected on a lower VaR, a preferred situation. The price of the eventual contracts has a Conditional Value at Risk (CVaR) consideration. Given that a higher contract price equals a homogeneous boost on all of the possible margins of the company, it affects only the mean of the distribution of the company's possible margins, not its variance. Furthermore, a lower VaR also contributes to a lower CVaR.

Then, if there is no indexation of the contract price to the system spot price:

$$\sigma^2_{WMgCuni} = \sigma^2_{PC-WSP} = \sigma^2_{PC} + \sigma^2_{WSP} - 2\sigma_{PC,WSP}$$

$$\sigma^2_{WMgCuni} = \sigma^2_{WSP} \quad (2.11)$$

The optimal contracting position for a firm is given by:

$$Ec^* = \frac{\sigma_{MgI,WSP}}{\sigma_{WSP}^2} \tag{2.12}$$

An important issue here is that, given a technological mix of generation on an electricity system, the optimal contracting position of a firm depends on its expected generation, the covariance between its generation and the spot price, and the variability of the expected spot prices of the system.

3 RESULTS

3.1 Efficient evolution of the SIC from current installed capacity, taking into account investment constraints

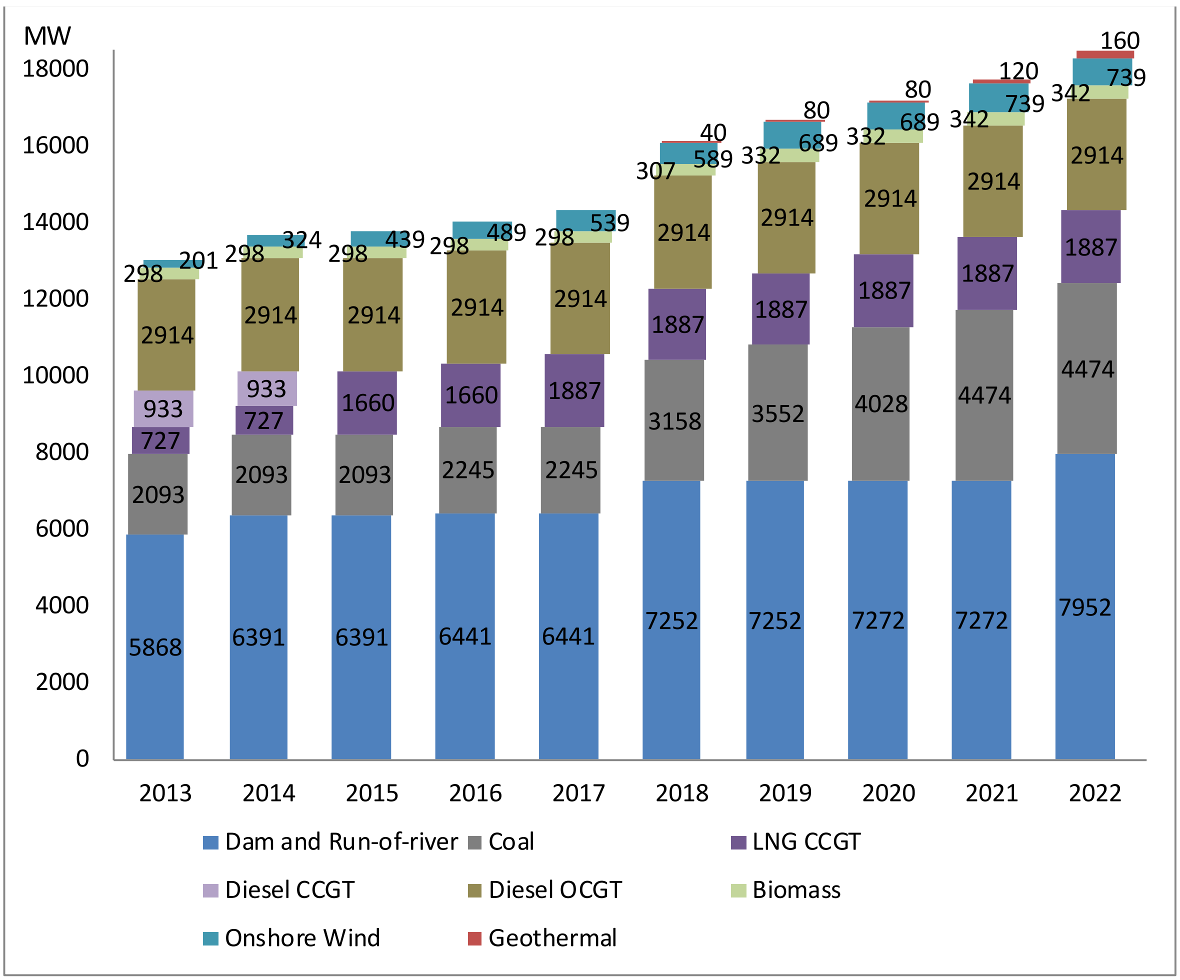

Figure 3-1 - The optimal evolution of SIC's generation park in 10 years considers expansion basically through coal investments, Hydroelectric generation and diesel CCGT conversion to LNG CCGT units. NCRE's participation is according to CNE's plan of investments[20]

[20] LNG technology in year 2015 considers both LNG CCGT plants ("San Isidro") and diesel CCGT plants converted to LNG ("Nehuenco" and "Nueva Renca") by investing in regasification units (e.g. FSRU)

The economically optimal evolution of SIC's generation park, based on efficiency conditions and subject to investment constraints, is presented in Figure 3-1. This economically optimal evolution results with the development of all hydroelectric projects available in the period, and with the doubling of coal installed capacity, necessarily performed in 5 years.

3.2 Optimal contracting position of the SIC

The operational conditions given by an economic dispatch on the SIC's previously described evolution, and optimal hydrology risk hedging considerations, have important implications. First of all, the most important observation from the analysis is that the total amount of energy contracted over the total system's demand, calculated as the energy that minimizes the variability of a monopolistic enterprise owning the entire SIC installed capacity, will never be enough to supply on LTC the expected demand in the period of study. It fluctuates from 77% in year 2013 to 83% in year 2022 (as reflected in Figure 3-2). This means for example, that if in year 2018 all efficient investments are performed, there will be an ideally committed 79.6% of the demand at fixed price on LTC. Consequently, there would be 13 TWh with difficulties in celebrating contracts given present regulation. Furthermore, when calculating this same index as the aggregated energy that the SIC companies are inclined to commit when they independently minimize the variance of their margin, the aggregated committed energy mirrors the prior, meaning that this framework does not rely on market concentration positions (see Figure 3-2).

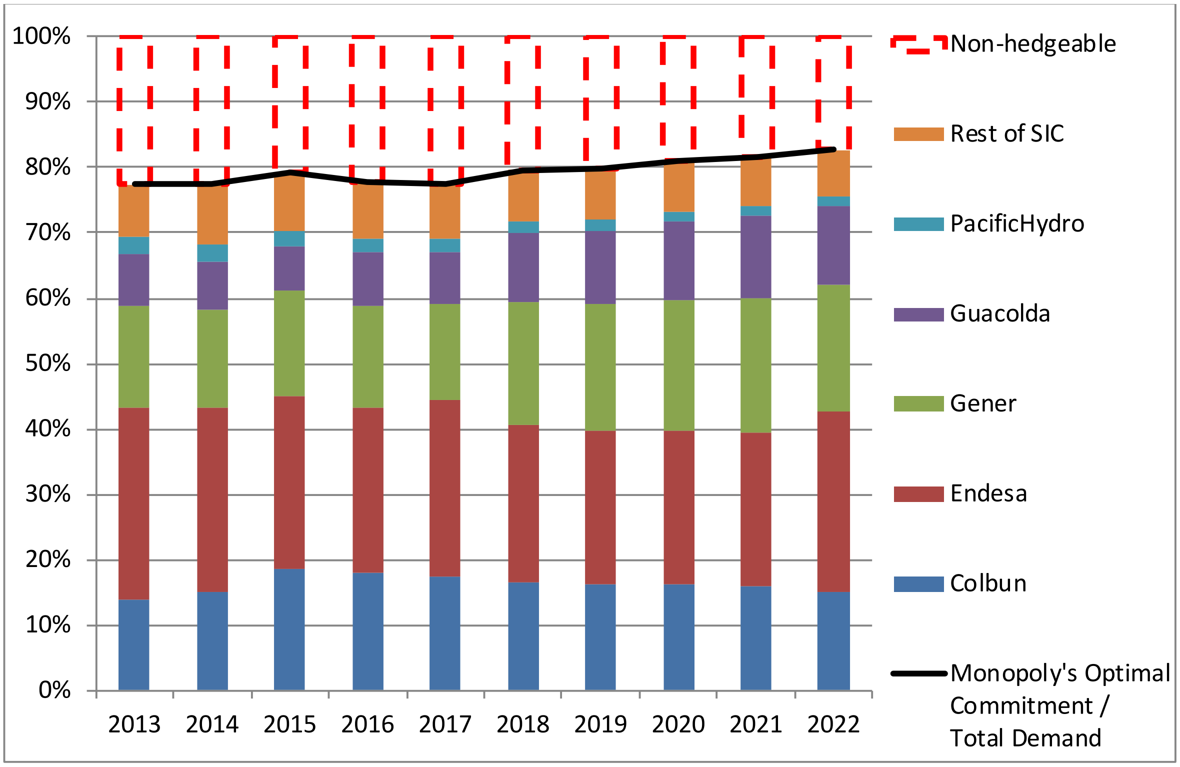

Figure 3-2 - The sum of the optimal contracting positions of the Chilean Gencos is exactly the same than the optimal contracting position of one unique monopolistic Genco. As a result, one can conclude that the analysis and design of risk allocation mechanisms would not depend on company ownership[21]. The adequate amount would never be enough to meet demand at a fixed price.

Predictably, when calculating the aggregated contribution of each fictitious company owning the whole generation capacity of a certain technology, the non-hedgeable energy of each year is the same as that calculated given the previous two methods (Figure 3-2). From this analysis, it is possible to conclude that each generation technology has a different inclination to assume energy obligations (see Figure 3-3), and that hydroelectric power

[21] After 2017, some assumptions are made on the property of the coming projects.

plants efficiently displace coal base generation, but are not suitable to commit the equivalent displaced energy on LTC because their generation is more variable.

It is not surprising that when calculating the optimal contracting position assuming three different ownership situations, one obtains the same system's results. This is consequence of the fact that the covariance between the spot price and each firm's margin is calculated over the totality of the system, and the margin of the system is distributed completely among the firms, however they are composed. This equivalence is a direct result of Equation 2.12. Take the following example; say the whole system is composed of two firms of relative size. In this example there exists an absence of both market power and market imperfection, and the system's margin is shared among them in the following way:

$$MgI_{SIC} = MgI_{firm\ 1} + MgI_{firm\ 2}$$

On the other hand, given covariance's properties, if the assumption is that market composition has no influence on the weighted spot price, then:

$$EcSIC^{*} = \frac{\sigma_{MgI,WSP}}{\sigma_{WSP}^{2}} = \frac{\sigma_{MgI_{firm\ 1}+MgI_{firm\ 2},WSP}}{\sigma_{WSP}^{2}} = \frac{\sigma_{MgI_{firm\ 1},WSP}}{\sigma_{WSP}^{2}} + \frac{\sigma_{MgI_{firm\ 2},WSP}}{\sigma_{WSP}^{2}}$$

This means that if a new power plant is starting up in a system with firm's already optimal contracting positions (no spot surplus or deficit resulting from contingencies), the additional contracting contribution to the system added by that plant is independent both of the organizational structure of the market and of the technological mix of the firm facing the project. This result stems from the fact that the power plant's impact on the system is independent of the owner.

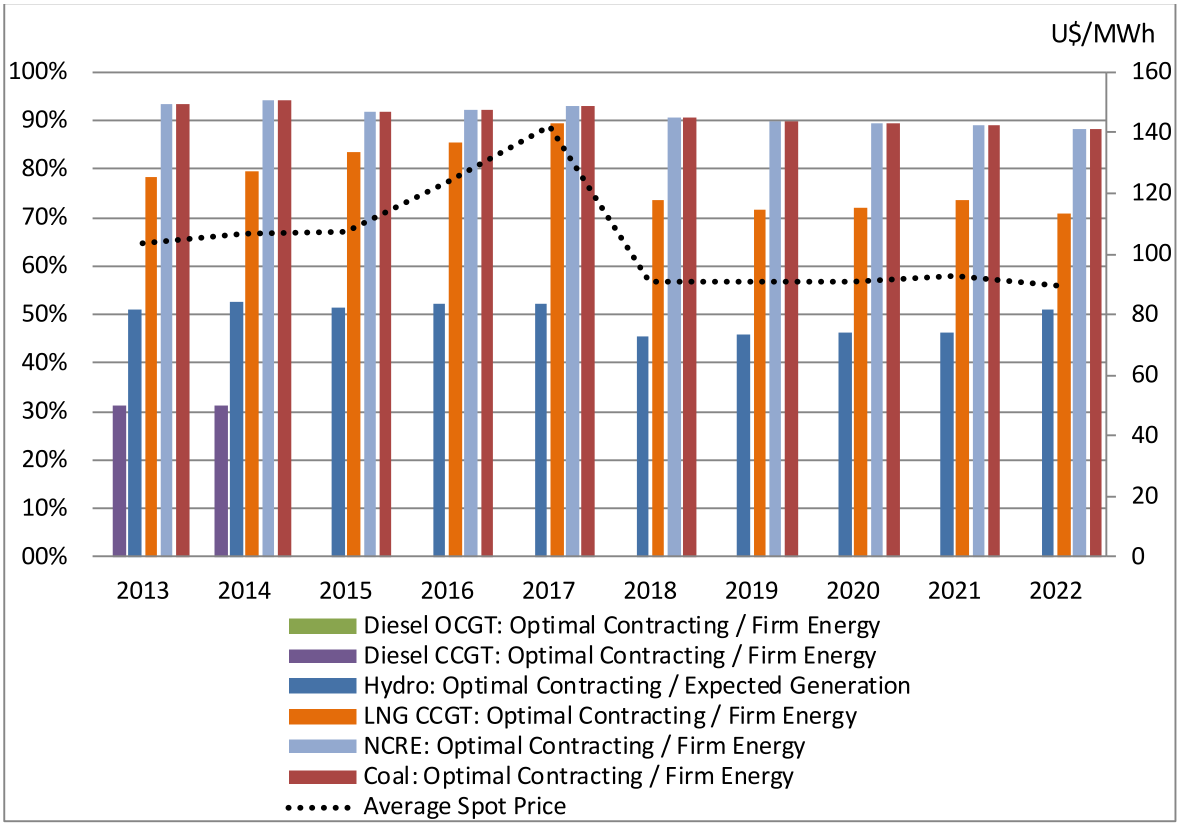

Figure 3-3 - Base technologies and NCRE (coal, biomass, wind and geothermal in this model) have a perfect correlation between their generation and the spot price. As a result, they are willing to assume assume contracts for a large percentage of their firm energy. On the other hand, OCGT reasonably does not commit energy on LTC

As stated above, Figure 3-3 leads to conclude that willingness to assume obligations over firm energy is different for each technology. It also helps to conclude that a technology's willingness to assume obligations over its firm's energy depends on market conditions: variability of spot price, system's technological mix, and operation costs to supply demand. In other words, the contribution of a new project on the contracting position of the system does not depend on the owner of the project, but on its technology and its impact on the system's conditions. It is also important to consider from Figure 3-3 that the estimation presented considers an almost full firm energy's contracting of NCREs. Other technologies with intermittent generation, like for example wind turbines, are in turn not able to assume LTC without first applying some form of financial mechanism. Finally, it is important to notice that despite an important expansion in coal installed capacity beginning in the year 2018 (ideally 914 MW), and the important contribution of coal in terms of the willingness to celebrate contracts regarding firm energy, the overall contracting position of the system would not change so much between 2017 and 2018. It would be improved on 2% of the demand, because hydrological risk influences every stakeholder, and there is together an important investment on hydroelectric power plants beginning in 2018.

Given this situation, one can conclude that in the year 2018, hydroelectric, coal and LNG will together form 94% of the SIC's energy obligations if agreeing to hedges that allow for significant reduction on margin's variability (as can be seen in Figure 3-4, Figure 3-5 and Figure 3-6[22])

[22] The margin for all contracts seen in Figure 3-4, Figure 3-5 and Figure 3-6 assume high contracting price, which does not influence total hedged margin variability, but instead only the margin's mean. The yearly margin on every one of the 51 hydrological situations is, solely for the purpose of this presentation, divided by the expected margin of the technology.

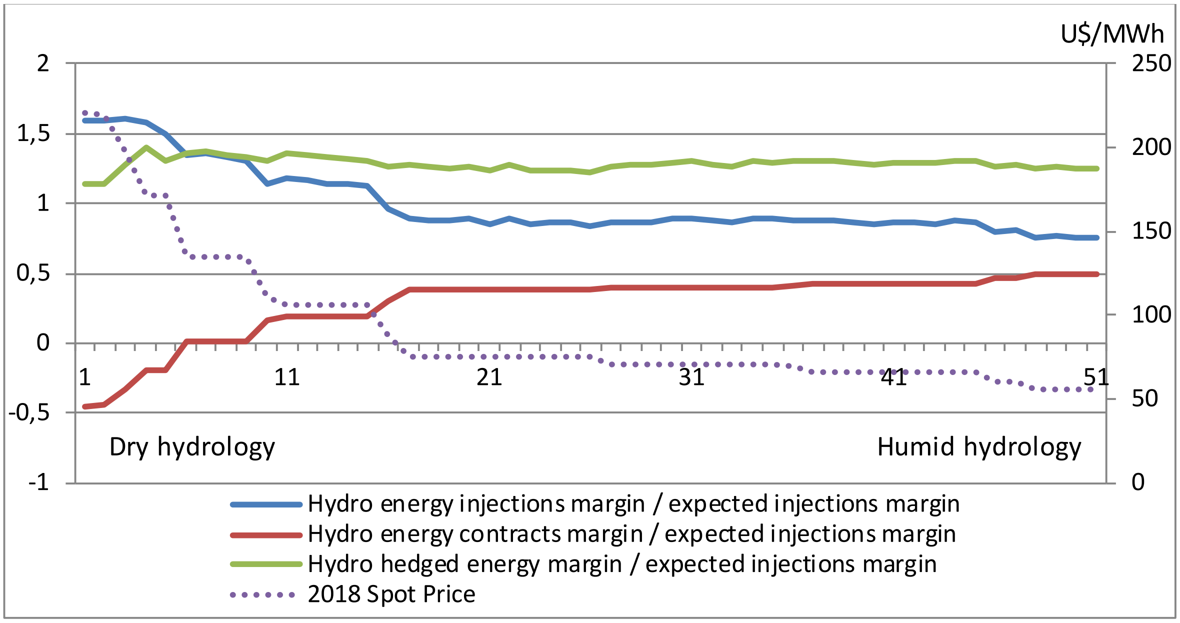

Figure 3-4 - Hydroelectric park injection's projected margin for the year 2018 has a correlation of 0.98 with spot price. Its variability is significantly reduced by 97% when assuming optimal hedging positions

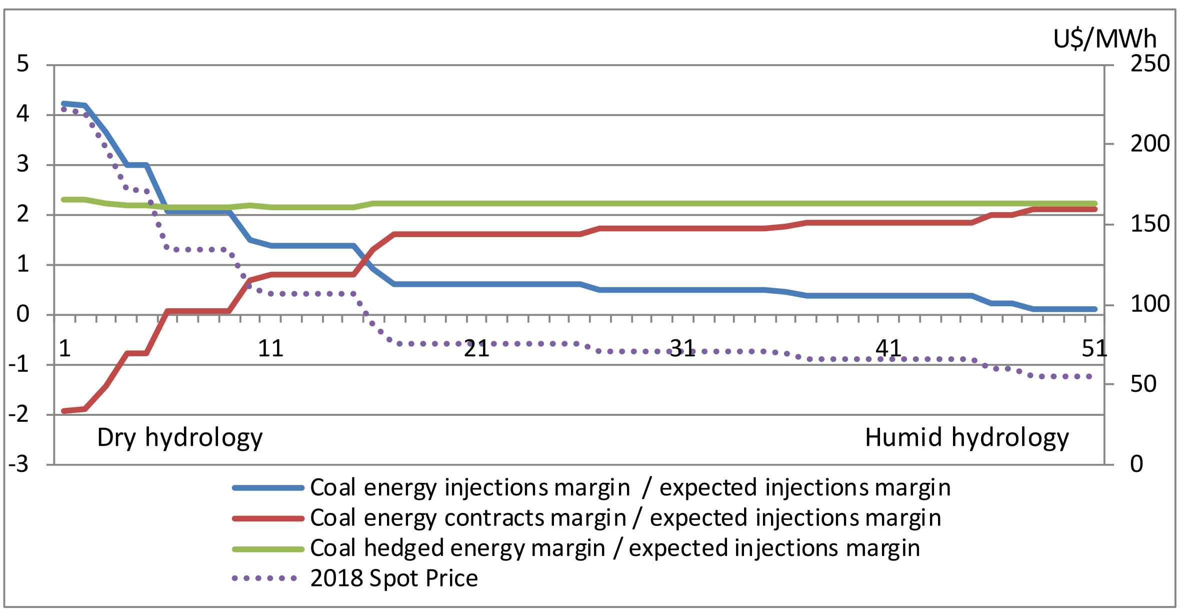

Figure 3-5 - Coal injection's projected margin for the year 2018 perfectly correlates with spot price. Its variability is significantly reduced by 99.9% when assuming optimal hedging positions

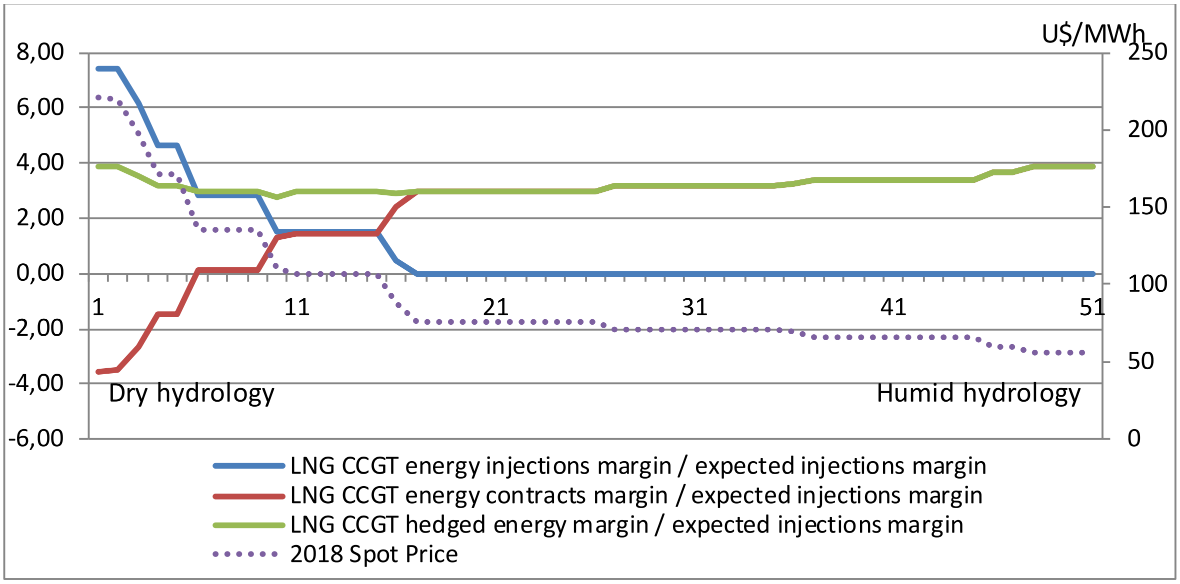

Figure 3-6 - LNG injection's projected margin for the year 2018 has a correlation of 0.99 with spot price. Its variability is significantly reduced by 99.2% when assuming optimal hedging positions

3.2.1 Coming difficulties on Discos contracting situation

Projections for the year 2014 on the SIC appear rather bleak. SIC's companies have already committed capacity above their optimal levels, and as a result, they would probably be unwilling to subscribe supply obligations without the existence of risk sharing mechanisms. The study concludes that 23% of the capacity that will be supplied in response to 2014's demand is unwilling to assume contracts. This is true given the impossibility of hydrological risk sharing, and considering the eventual possibility of perfectly hedging the rest of the risk factors.

Even with projects starting up late in 2013 (in 2014 in this yearly model), the system is not projected to be able to improve its contracting position from the 2013 critical situation. In

2013, Chilean Gencos faced uncertainties such as supplying energy to Discos without contracts, and regarding the mechanisms of remuneration of this already provided energy[23]. A similar situation occurred in September of 2011 by reason of the insolvency of "Campanario S.A.", a company owner of some OCGT which adjudicated auctions that it could not fulfill. This situation resulted in that the rest of the Gencos continued supplying Campanario's energy in proportion to their firm energy during a first period[24], and then in proportion to their energy injections[25], necessarily ending at loss. Cap prices of 129 U$/MWh on SIC 2013 auctions (significantly higher than system development cost driven by coal and compared to average auction prices of 80 U$/MWh) have not been enough to ensure Discos supply, because the problem is not only a matter of price, but also of an inappropriate risk allocation scheme dragged from the past and tied up into already signed contracts. As formerly stated, prices situated at a level above the expected spot price would incentivize more energy obligations, this however, considering an important risk-premium. What should then follow is the clearing away of inefficient conditions influenced by a lack of base generation, and a scarcity of water inflow for four years.

According to Street et al., 2009, there are four important points that must be considered when building the optimal contracting strategy of a firm: (1) time horizon of the contracts; (2) environment of negotiation of such contracts (e.g., auctions or free negotiation); (3) risk factors affecting future contract outcomes and; (4) agents' risk-profile or risk-adversity. The assessment presented in this work only considers hydrological risk affection and also

[23] The authority's clarification was communicated on August 2013 for the energy supplied on December 2012, on the resolution "Oficio Ordinario 7230" of the Chilean Electricity and Fuels Superintendence (SEC)
[24] According to the resolution RE2288 from the Chilean Economy Ministry
[25] According to the resolution RE239 from the Chilean Economy Ministry

considers only absolutely averse agents. It does not try to assess or explain bidding strategies, nor does it consider implicit risk-premiums on auction cap-prices. The results demonstrate a deficit on willingness to contract demand, even under optimal capacity expansion. These results can be solved by either assuming higher procurement prices, or by implementing hydrological risk sharing mechanisms.

It is important to highlight that the study presented here only takes into account systemic hydrological risk management. This management is not only more relevant given a hydrothermal generation environment, but it is also non-diversifiable. Risk factors such as fuel price or supply risk, regulatory risk, demand risk, performance risk, environmental compliance risk, and uncertainty (Gaussian noise) over expected spot prices are neither considered in the evaluation, nor correlated with hydroelectric conditions. No transmission constraints were considered, since they have no relation with hydrological risk. Consequently, the optimal contracting positions described in this study represent an optimistic estimation or higher bound of effective optimal contracting positions. These estimations were calculated only as the yearly energy that a company would optimally commit, without taking into account the effect resulting from the extension of the LTC on the willingness to contract, nor future obligation arrangements. As a result, these estimations are really a higher bound of system´s effective optimal contracting positions, modeled as a one-year contracts. Moreover the optimal contracting positions were calculated only according to a unique market vision. As a result, a single efficient plan of investments is projected for all the companies, and this plan is quite generous in comparison to actual SIC expansion projections. In practice, private agents drive decisions in the Chilean market. Investment and contracting resolutions thus respond to their own market vision, spot price projections and system expected evolution. In that sense, these estimates do not pretend to present exact values for designing public policies, but instead attempt to demonstrate how incorrect hydrological risk allocation mechanisms imposed on regulation, drive energy auction problems and fuel polemic internalization of a systemic risk.

Since deregulation, the practice in Chile has been that all of the regulated demand be contracted at fixed prices. This strict method wavered in two different occasions when, due to contingencies, temporary risk sharing mechanisms with consumers were implemented (for consumptions of 2005-2008[26] and 2010-2011[27]), both of them after the adoption of the auction's scheme on behalf of regulated clients. Those emergency mechanisms considered sharing more risk factors than only hydrological variations, since spot price indexation was important on those periods for transferring some other uncertainties. Anyway, this study helps demonstrate that hydrological risk transfers are really structural mechanisms needed in the design of the system. Both the correct design of auctions for proper economic signals and suitable risk allocation according to risk aversion profiles, and an analysis of the underlying causes of the change in willingness of Gencos to supply, are some interesting perspectives suitable for a different study. What is most vital today is to expose the problems inherent in the design of auctions, issues that are clearly unsustainable in the long run. Deficits on base-load energy projects, a change on auctioned LTC risk-premium at actual cap-prices, and a sustained increase in international diesel prices meaning a higher

[26] Compensations to Gencos based on differences between Node Prices and Spot Prices were performed. Problems arose because some Discos did not have energy supply contracts.
[27] Average Spot Prices indexations to Discos supply auctions, with cap-price limits, were performed. Mechanisms were considered to avoid more Discos' deserted auctions.

spot price variance, may have led to a situation where Gencos are inclined to not supply demand rather than assume higher risk for lower-than-expected prices (due to calculated cap-prices). This apparent tendency may be further incentivized if these current systematic problems seem more permanent than fleeting. Since the lack of base-load generation projects means a long-term disengagement between spot prices and auctions cap-prices, this situation boosts the attractiveness of the spot market over the LTC market. In every market, especially in the electricity market where generation adjustment to demand takes several years to stabilize, there are natural deviations to optimal situations. The market regulation design must consider the possibility and incentives to adjust on the short and medium-term to long-term disengagement.

3.3 Sensitivity: Optimal evolution of the SIC if the previous investment decisions were optimal

In order to correctly weight the causes of the difficult situation facing the SIC regarding energy supply to Discos, sensitivity to the previous methodology was performed. In this case, the optimal evolution of the SIC was calculated based on the pretense that in the year 2013, when starting the analysis, an optimal and economically adapted system was created overnight, i.e., the SIC's current installed capacity was not considered. This framework serves to clarify the reasons for sub-optimal decision-making in past times of contingencies like for example, the over installed capacity of OCGT by reason of the "Argentinian gas crisis". In that sense, this sensitivity considers neither plants being constructed nor NCRE's introduction according to plan of investments. It also does not consider the possibility to convert CCGT power plants, and assumes that any technology expansion requirement should be performed at any time for any quantity. Finally, in an optimal and economically adapted system, the capacity payment done in Chile to incentivize peaking power plants can be perfectly calculated ex-ante every year, without the uncertainties given by effective peak demand. As a result, and when considering Chilean remuneration methods, it is really more beneficial to install OCGT power plants, than to assume supply failures or blackouts.

The conclusion derived from the previous projection is that, even given optimal efficient evolution of the energy matrix of the SIC, and a perfect hedge of every risk factor, economic conditions for full demand contracting in the absence of hydrological risk-sharing mechanisms do not exist. The SIC's ideal contracting position is not able to fully cover the demand on the horizon studied. The optimal situation for the year 2018 considers 79.8% of energy contracting for the whole system, similar to the projected situation for the base case of 79.6% (presented in Figure 3-2), but facing lower spot prices (85 U$/MWh) and lower variability (12% lower). The optimal installed capacity and each of the technologie's willingness to contract is shown in Figure 3-7. Both simulations consider the same hydroelectric installed capacity, because in both cases, every hydroelectric project is efficient.

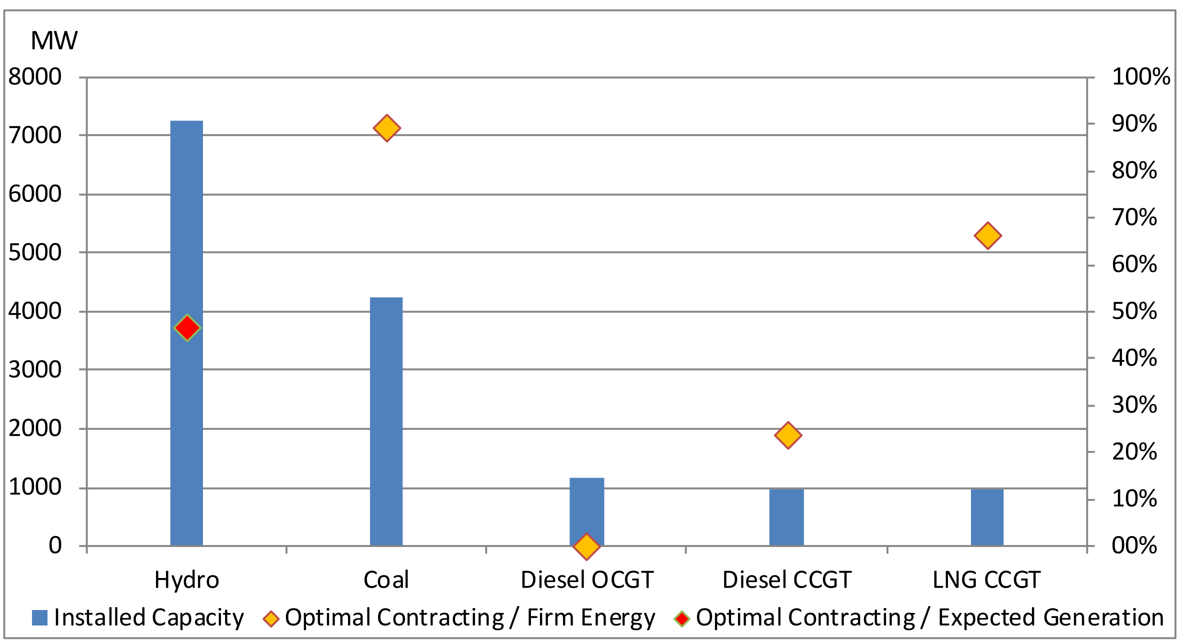

Figure 3-7 – 2018's installed capacity and optimal contracting over firm energy per technology (expected generation for hydroelectric park) on ideal system. With lower spot price and spot price variance than real system's situation evolution, the optimal contracting position of the system is almost the same: 20.4% of total demand would not be freely committed in LTC.

3.4 Sensitivity: The effect of hydroelectrical participation on energy mix over the optimally invested system's willingness to contract

Despite the fact that the CNE selects some of the hydroelectric projects in its plan of investments for the expansion of the system, there are other hydroelectric possibilities of expansion were flows and hydrological information are considered. This sensitivity analyzes the impact of higher hydroelectric participation in a hydrothermal system and so also considers other projects that the CNE excludes from its plans[28]. Moreover, an even greater participation of hydroelectricity on generation portfolios is considered in a second overview of this sensitivity[29].

Comparing hydroelectricity participation overviews and the ideal scenario presented just before, both for the year 2018 (section 3.3), it is worth mentioning that overall optimal contracting decreases with an increase in hydroelectric installed capacity. Furthermore, the contracting contribution of every technology over its firm energy, decreases. A higher capacity of hydroelectric base generation replaces coal base investments and implies the need of more peaking technologies (see Figure 3-8). The impact of higher hydroelectric capacity over hydroelectric generation margin's covariance (numerator in Equation 2.12) is more significant than over coal, but means an important substitution of coal's installed capacity. As a result, the system's deficit of committed energy is emphasized on a mixed hydrothermal system with a higher hydroelectric participation.

[28] Thus the startup of 157 MW in year 2017 and 1.007 MW in year 2018 (timings estimated according to press release information)
[29] Thus the start up in 2018 of 3.000 MW of a fictitious hydroelectric power plant with both average flow characteristics among hydrologies, and average response to peak demand

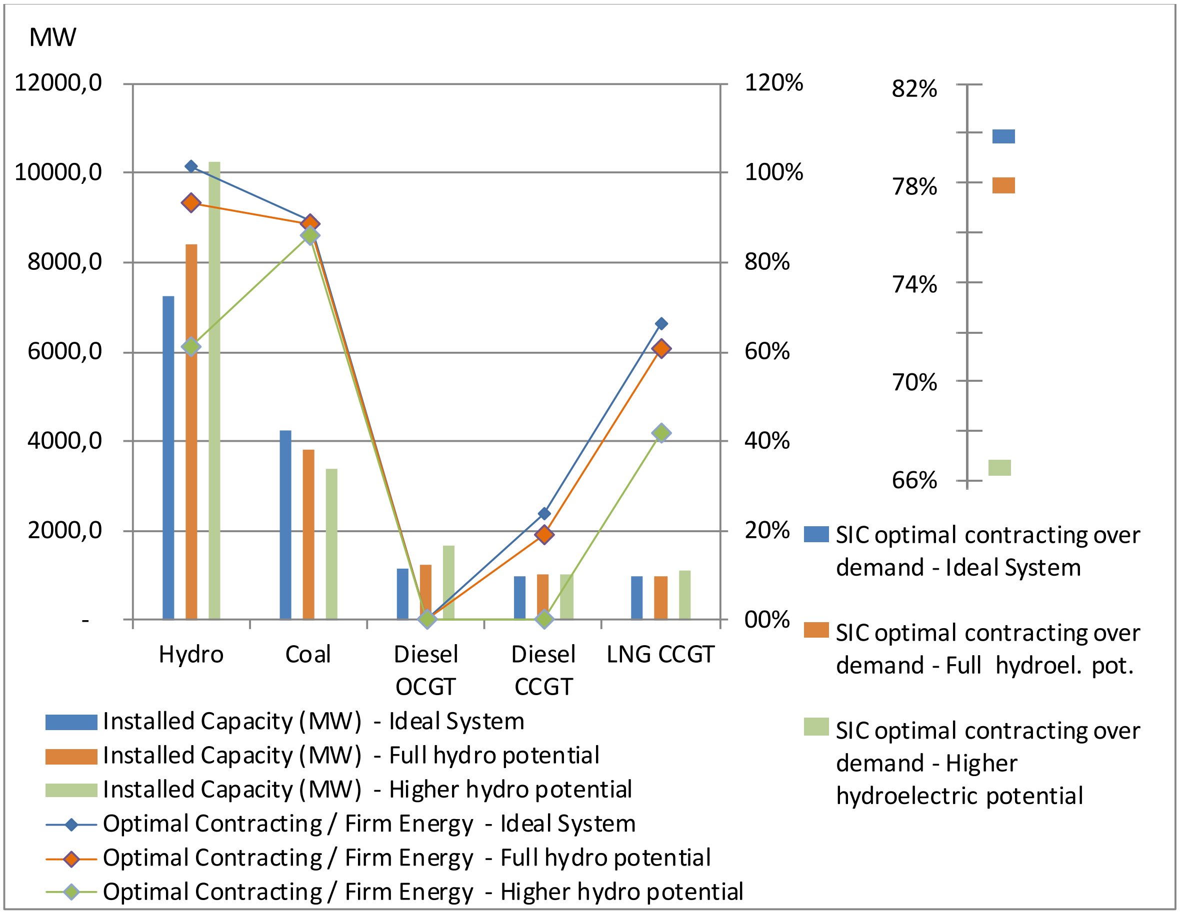

Figure 3-8 - Installed capacity and optimal contracting per technology in year 2018. A higher participation of hydroelectric generation on the system means an important decrease of optimal contracting of the SIC, and every technology is willing to assume less obligations[30]

[30] Firm energy for each hydroelectric power plant is arbitrarily defined as its generation capacity on the four driest hydrological conditions. Firm energy, in consequence, can be conceived as a fraction of the expected energy of each plant.

3.5 Sensitivity: The effect of constrained coal investments

Nowadays the Chilean SIC is facing difficulties because of social opposition to both hydroelectric and coal base investments. This opposition is in part due to the environmental impact of the eventual projects, and to their difficult relationship with the area's settled communities and/or activities. This situation precludes the possibility of economically efficient expansion, and the resulting optimal pricing for clients. Particularly if actors among the electricity system face incertitude in coal base generation projects, they would have to replace in optimal conditions the efficient investments mainly for LNG generation. This would incidentally affect optimal contracting of the entire system as shown in Figure 3-9 for the year 2018, if compared to the same year on the base case presented in sections 3.1 and 3.2. Coal projects are nowadays sub-optimally invested. Because of typical investment lead times, it would only be possible to catch up with efficient investments in 2018. On that year, ideally, an important introduction of 914 MW should be performed, in order to revert the stressed projected situation (see spot prices on base case presented in sections 3.1 and 3.2). A progressive constraint on the possibility of coal investments on the 10 years spectrum of analysis would primarily restrict investment in year 2018, shown in Figure 3-9 (when there would be, for example, an introduction of 448 MW of coal if the maximum investments on the whole horizon would be 600 MW). Its impact over system conditions would be felt by hydroelectric generation and LNG, since both would optimally commit less energy on LTC, with the consequent decrease on overall contracting.

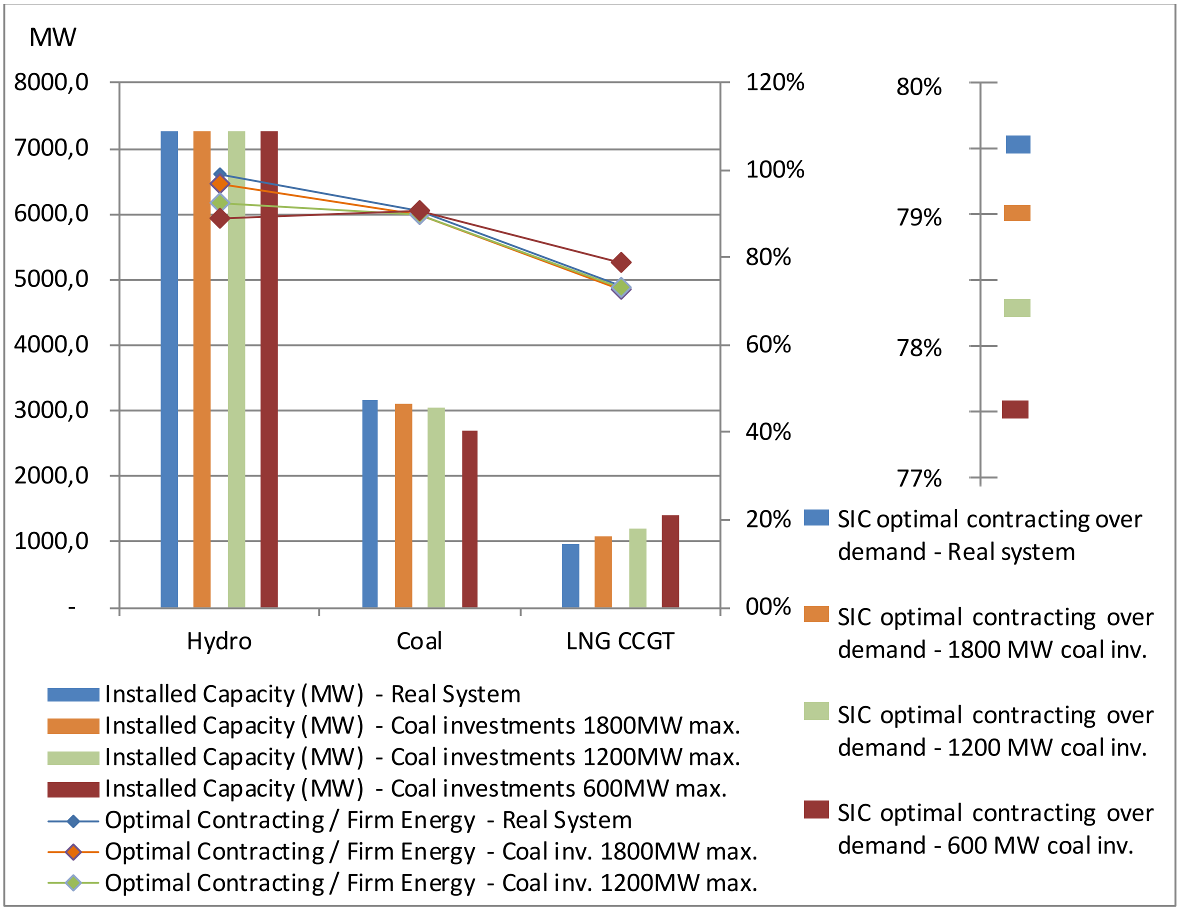

Figure 3-9 - Installed capacity and optimal contracting per technology in year 2018. Progressively constraining coal investment with the possibility of substituting with LNG CCGT investments means a decrease in the overall contracting position from 79.6% on real system to 77.5%, with a maximum of 600 MW of coal projects (a decrease of 1.34 GWh). The effect over the willingness to assume contracts by hydroelectricity drives the overall decrease[31]

[31] The rest of the technologies were not shown because of less relevant changes in positions (diesel OCGT, diesel CCGT, wind, biomass, geothermal)

3.6 Sensitivity: The effect of constrained coal investments without substitution by LNG

A firm's decision of investment in an electrical system in most of cases depends on the decisions of the rest of the stakeholders, especially competitor companies. If the market considers that an investment is to be performed until completing efficient investment for projected demand, then a competitor's similar investment would be discarded. In that sense, if an expected investment suffers unexpected problems by judicial orders or socio-political problems (similar to "Castilla", "Barrancones" or "Punta Alcalde" in Chile's recent experience), then it is impossible to catch up with efficient investments given typical lead times. Furthermore, if the expected investments for coal beginning in year 2018 are unable to be carried out, then the deficit of generation would not only impact the upward motion of spot prices, but also undermine the willingness to assume energy obligations.

A decrease of a single MW of coal installed capacity should not be linearly associated with the decrease of a single GWh of willingness to commit energy. This lack of association is due to the effect on LNG's dispatch and spot prices, which equal a non-linear compensation on willingness to assume contracts of other technologies (see Figure 3-10). For instance, a decline of 300MW on coal's optimal capacity in 2018 means an almost negligible increment of overall contracting of 0.1%, because of a compensation of contracting over firm energy of the rest of the technologies (as seen in

Figure 3-10). On the other hand, a decline of 600MW on coal's capacity signifies a reduction of 0.3% on the SIC's contracting capacity compared to optimal expansion, with an increment of mean spot prices of 27 U$/MWh.

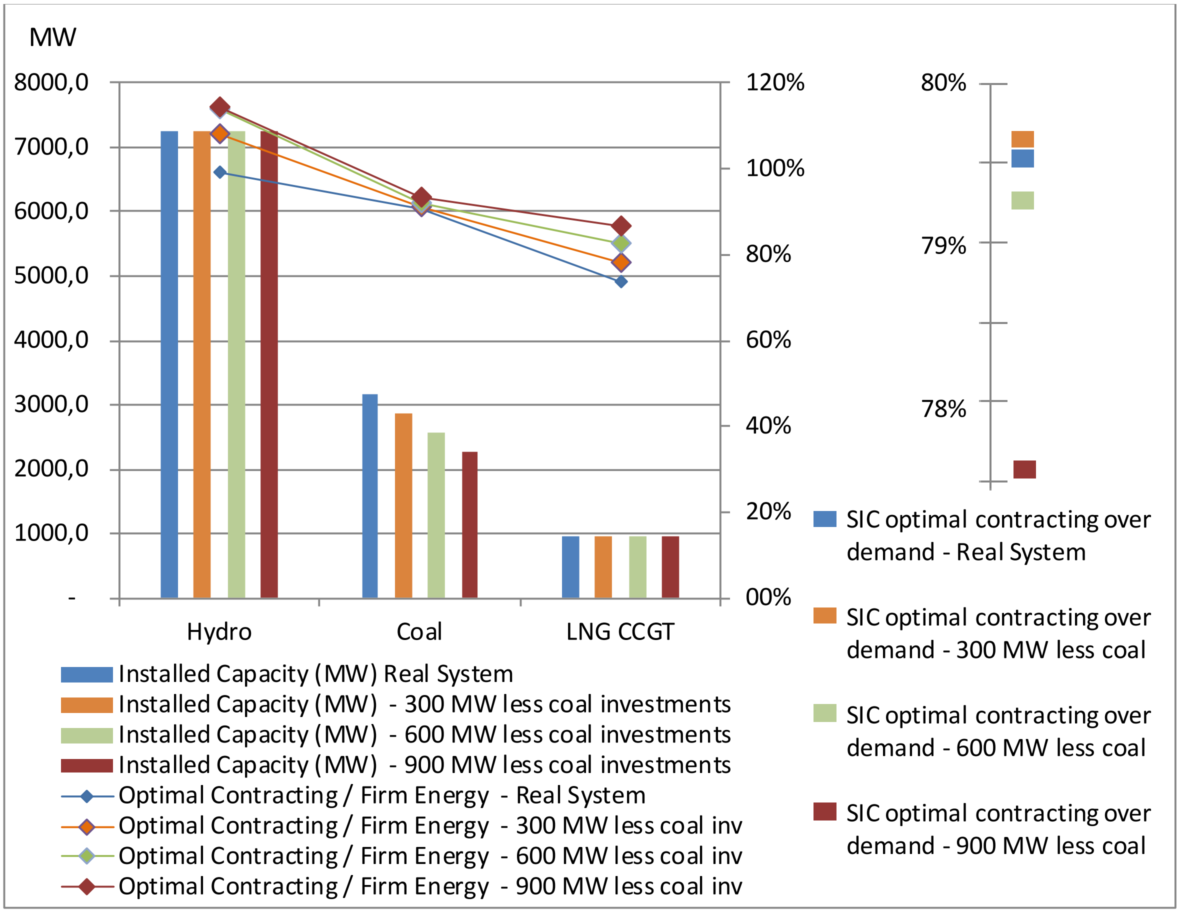

Figure 3-10 - Installed capacity and optimal contracting per technology in year 2018. Progressively constraining coal investment without the possibility to react substituting with LNG, means a decrease in the overall contracting position from 79.6% on real system to 77.6% with 900 MW of coal projects lacking. An increment of contracting position of each technology is not able to compensate the deficit of coal capacity[32]

[32] The rest of the technologies were not shown because of less relevant changes in positions (diesel OCGT, diesel CCGT, wind, biomass, geothermal)

3.7 Sensitivity to a CO2 emissions tax

Nowadays a CO2 emissions tax is being discussed, whether for energy generation in Chile, or for every contaminating source on the productive system, for example, transportation. Particularly in the energy sector[33], an emissions tax introduced by 2015, and incorporated as a variable cost, would mean not only a substitution of coal for LNG, but also a decrease in the overall contracting position of the SIC (as exposed in Figure 3-11), given the negative impact over the hydroelectric park's willingness to acquire obligations. The hydroelectric park's contractual position would decrease since the variability of its un-hedged margin is already reduced by the effect of the impact of taxes over spot price (see Figure 6-3). As a result, a reduced hedging position for similar variability results on hedged margin is needed.

[33] Emissions considered: 0.97 Ton CO2/MWh generated with coal – 0.89 Ton CO2/MWh generated with diesel OCGT – 0.54 Ton CO2/MWh generated with diesel CCGT – 0.41 Ton CO2/MWh generated with LNG CCGT

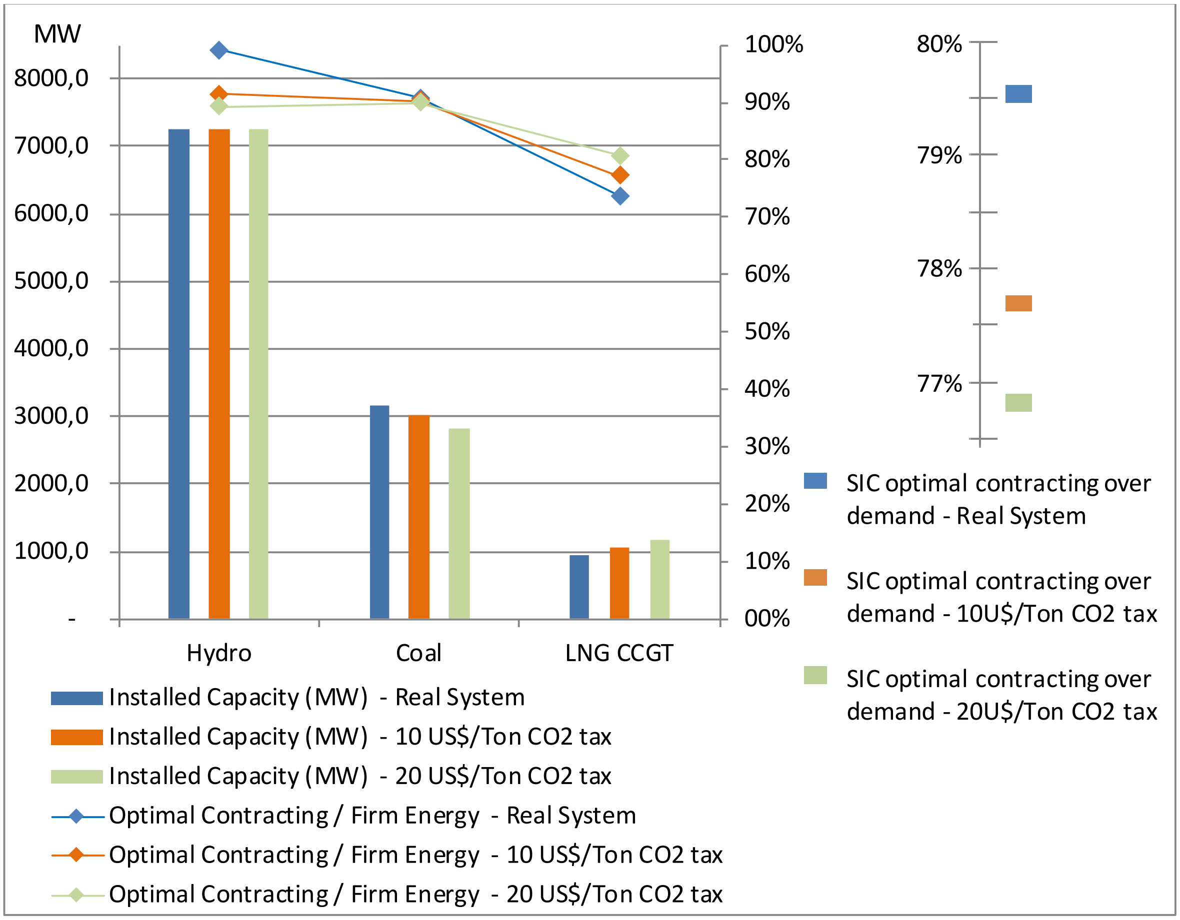

Figure 3-11 - Installed capacity and optimal contracting per technology in year 2018. The higher the CO2 emissions tax, the more negative the impact is over SIC's optimal contracting. While LNG commits more of its firm energy with higher taxes, the hydroelectric park commits less. This is explained by the impact of taxation over spot price (see Figure 6-3)[34]

[34] The rest of the technologies were not shown because of less relevant changes in positions (diesel OCGT, diesel CCGT, wind, biomass, geothermal)

3.8 Sensitivity to the expected spot price variability

If market situations like the ones recently experienced in Chile (prolonged droughts and judicialization of base energy projects) confront the system's actors with uncertainty over expected spot prices, then optimal contracting would not only be affected by market conditions, but also by a variability of expectations that are unable to be incorporated in scenarios. Considering a Gaussian noise over the expected spot price of a given year, with variability σ_n but null mean ($n_{bl} \sim N(0, \sigma_n)$), the spot price for that year would be:

$$SP'_{bl} = SP_{bl} + n_{bl}$$

$$WSP'_{bl} = WSP_{bl} + n_{bl}$$

And the injections margin would be:

$$MgS' = \sum_{bl} Eg_{bl} \cdot (SP'_{bl} - VC)$$

Then, from Equation 2.12,

$$Ec^* = \frac{\sigma_{MgI',WSP'}}{\sigma'^2_{WSP}}$$

The numerator would, in consequence, turn to:

$$\sigma_{MgI',WSP'} = \mathbb{E}([Eg \cdot (SP + n) - Eg \cdot VC][WSP + n])$$
$$- \mathbb{E}(Eg \cdot (SP + n) - Eg \cdot VC)\mathbb{E}(WSP + n)$$

$$\sigma_{MgI',WSP'} = \mathbb{E}([Eg \cdot SP - Eg \cdot VC][WSP]) - \mathbb{E}(Eg \cdot SP - Eg \cdot VC)\mathbb{E}(WSP)$$

$$\sigma_{MgI',WSP'} = \sigma_{MgI,WSP}$$

While the denominator would turn to:

$\sigma^2_{WSP'} = \sigma^2_{WSP} + \sigma^2_n$

In consequence, if $SP'_{bl} = SP_{bl} + n_{bl}$:

$$Ec^* = \frac{\sigma_{MgI,WSP}}{\sigma^2_{WSP} + \sigma^2_n}$$

This prior expression means that if actors face uncertainty over expected spot price for a given year, then the eventual contracting assumed by the actors would be inferior to the optimal contracting driven by a hydrological risk hedging analysis.

4 CONCLUSIONS

This work studies the desirability of a hydrothermal electrical system to commit energy on long term contracts (LTC) without hydrological risk sharing mechanisms among Gencos and the rest of the system's stakeholders. It calculates the optimal contracting position of a risk-averse Genco as the amount of energy that minimizes the volatility of the commercial margin of the company.

This study concludes, primarily, that even in an optimal system (in terms of investments and operation efficiency), in the absence of hydrological risk sharing mechanisms, there are no proper incentives to allow full demand contracting on LTC at fixed prices. Even if every efficient investment in generation was to be performed, the optimal contracting position of the system would not improved in a 10-year horizon. Considering the SIC installed capacity, operation costs and demand for the year 2013, this study concludes that Gencos' optimal contracting position would imply excluding 23% of the demand subject to fixed price contracts; this because Gencos would not be willing to commit more. This percentage only slightly dimishes up until 2022, when 17% of the forecasted demand would remain without contracts.

Given the conditions of the already signed contracts, Gencos, and more recently, free clients, are the only ones assuming spot-price risks. This situation has led to some of Discos' recent auctions to be declared partially or totally deserted. The regulatory conditions in Chile are not capturing this situation, but are instead forcing exogenously-driven risk allocation schemes among stakeholders. This risk allocation schemes imply costly appointments for the system: the regulated consumers are facing high costs, and because authorities are not considering the consumers' optimal exposure to spot market or hydrological variations, both free clients and Gencos are dealing with high risk exposure. This depends on the willingness of a consumer to pay higher prices at a fixed rate, considering demand uncertainty, and the willingness of the supplier to commit more energy than its optimum, at the expense of higher variability. Under current regulation, higher price-caps are the quick solution to the unattractiveness of supply auctions. Consequently, a risk allocation problem is being approached with an expensive alternative as a means of solution. The main worry is that perspectives for future auctions consider more deserted processes because of unavailable firm energy from Gencos, and difficulties in completing base-load energy projects. Despite this problem, the greatest goal of this study is to demonstrate that, even completing every efficient (socially optimal) project until 2022, there would remain an important portion of the demand that Gencos would not be willing to supply without hydrological risk sharing mechanisms. This, because the exposed problem is not only due to a lack of investment, but rather to the uncertainty imposed by hydroelectric generation variability. If the authorities continue to isolate regulated clients from their exposure to hydrological risk, then Gencos would probably continue to expect a risk-premium by means of higher bidding prices.

Furthermore, even in this study's modeled optimal system, a system economically adapted to the operation and investment costs faced in Chile, and developed as if every past decision was efficient, the contracting situation and the appeal of auctions would remain unchanged. When sensitizing the model to a bigger exposure to hydroelectric generation, it is possible to note that despite lower costs to the system as a whole, the desired committed energy of the SIC dramatically decreases. On the other hand, when sensitizing the model to constraints on base-load technologies like coal, and having the possibility to substitute coal generation by installing LNG Combined Cycle Gas Turbines, the overall effect is always a lower compromise of the total system, driven by the hydroelectric park's lower willingness to assume obligations. Furthermore, if coal's installed capacity is also constrained, and the system is unable to react by investing in LNG projects, then the spot price would significantly increase. However, the effect over the system's optimal contracting point would nonetheless be contained, given the increased willingness of other technologies to commit, such as LNG and hydro. Finally, the effect of a CO2 emissions tax over the system's willingness to assume obligations was quantified. The conclusion was that the reduction on hydroelectric contracting positions, and a coal substitution for LNG, drives a reduction of the whole system's desirability to engage in new contracts.

The correct design of auctions for achieving both proper economic signals and suitable risk allocations, according to risk aversion profiles, is an interesting perspective worthy of further analysis in future research. It is also important to analyze the underlying causes of a change in the willingness of Gencos to supply, and the influence of the spot market's risk-premium. Anyway, this study serves to clarify that a mechanism for sharing hydrological risk should be considered. Such mechanisms could include drought insurance with international companies, indexation of precipitations on an auction's energy price, inclusion of financial derivatives such as callable and puttable forward contracts proposed by Gedra 1994, or exposure of Discos to business risks. It could even consider exposure of the demand side to spot prices, by reducing full contracting requirements, or by indexation to spot prices in auctions' energy prices. These mechanisms, properly conceived, would lead to clear efficient conditions, according to the risk-averse profiles of clients and Gencos, and would permit the triumph of efficient procurement prices.

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6 APPENDICES

APPENDIX A: CONSIDERED LEVELIZED COSTS

The 2013 levelized costs composition considered as inputs to the model can be seen on Figure 6-1, while their projected evolution is depicted in Figure 6-2 .

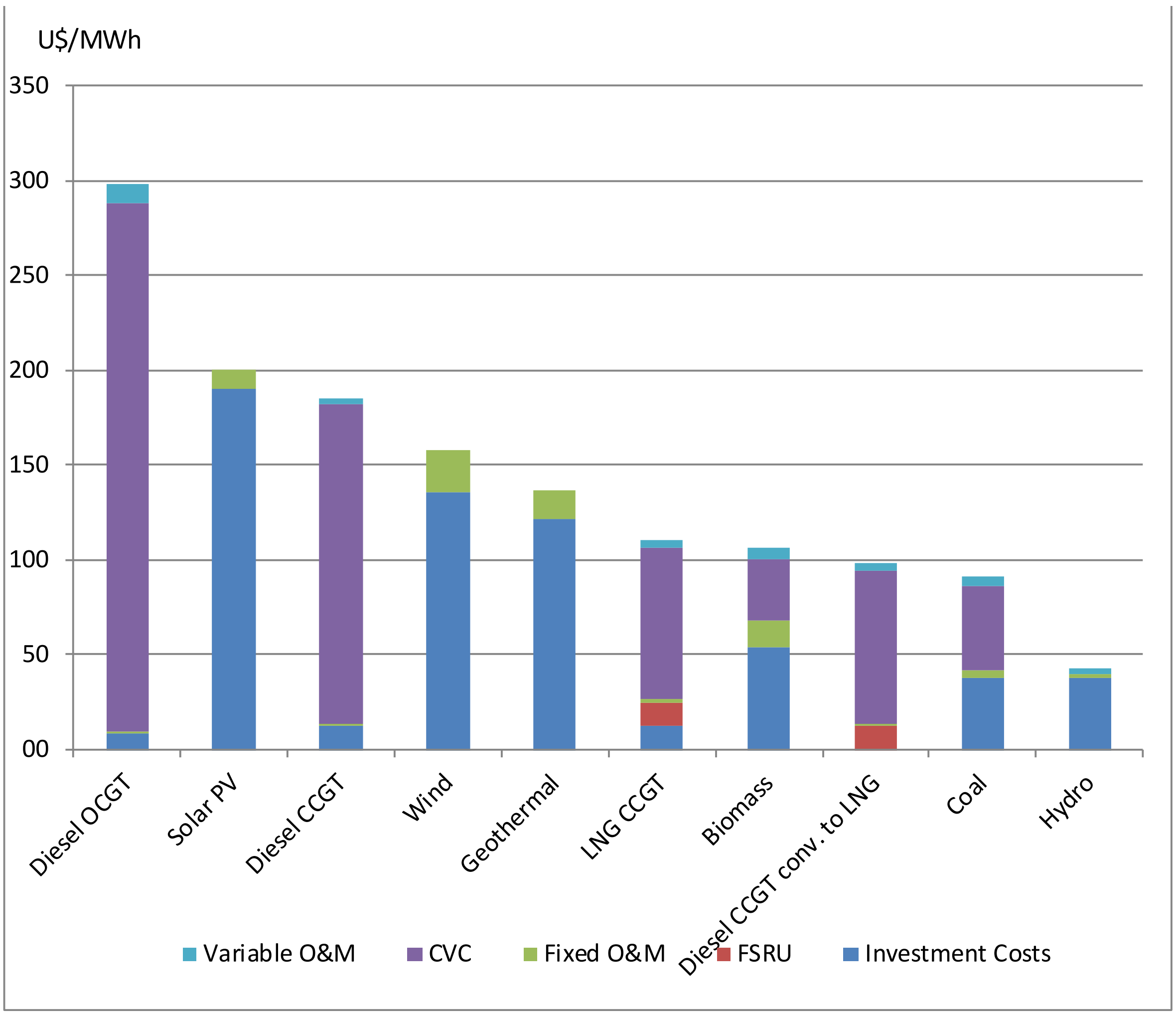

Figure 6-1 - 2013 levelized costs of technologies[35]

[35] FSRU: floating storage regasification unit, alternative to a regasification terminal.

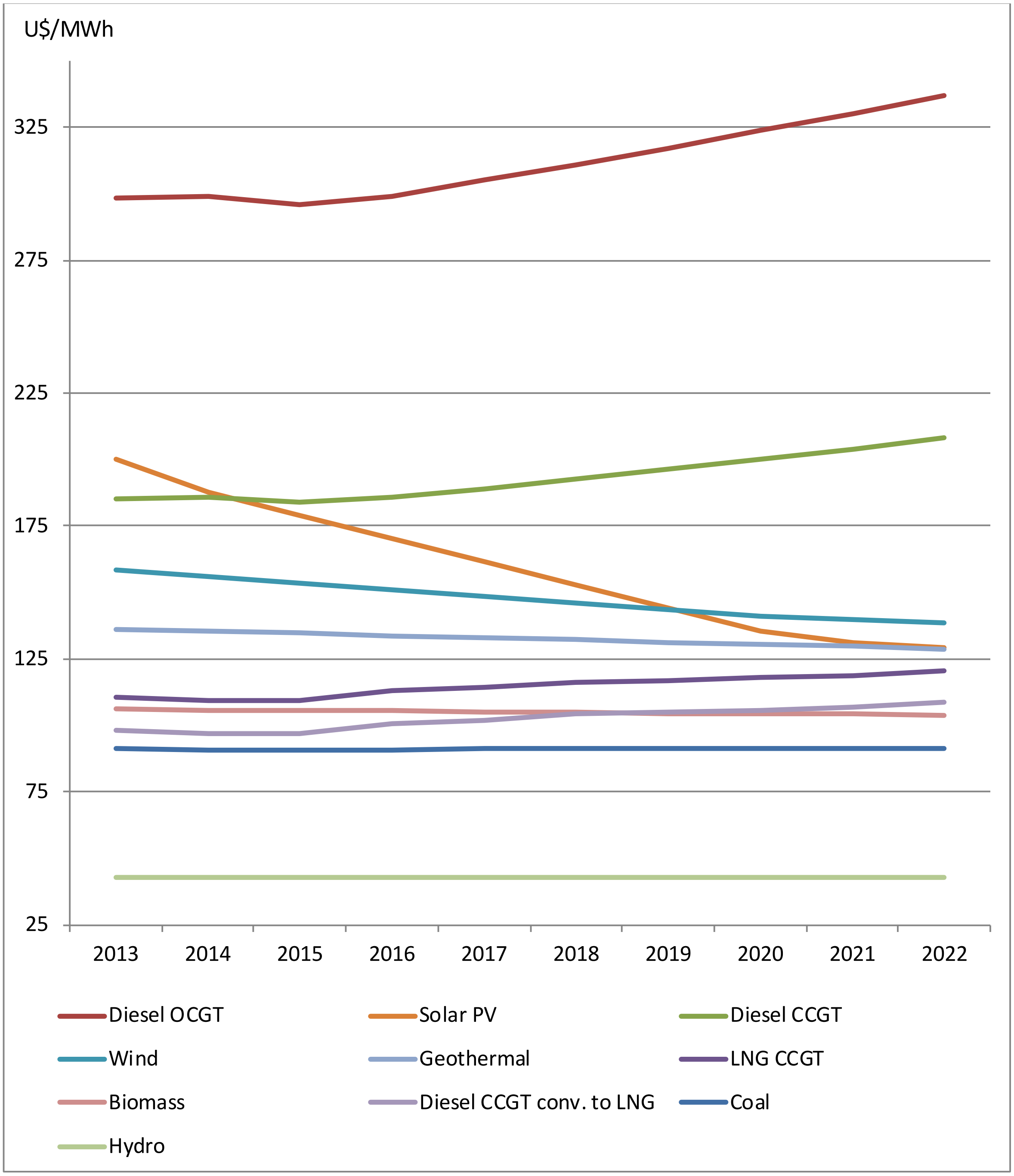

Figure 6-2 - Projection of levelized costs of technologies[36]

[36] Sources:

- 2013 Annual Energy Outlook, US Energy Information Administration
- April 2013 *Informe Técnico Definitivo Fijación de Precios de Nudo*, CNE

APPENDIX B: MODELING HYDRO POWER PLANTS

The planning model used for the optimal expansion of the SIC considers a coefficient that reflects the variations on generation of a hydroelectric power plant depending on hydrological conditions, HA. So Table 6-1 through Table 6-6[37] considers the operational condition of every single hydroelectric power plant or hydroelectric project in Chile for every one of the 51 hydrologies (yearly generation over nominal power). The coefficients for the run-of-river power plants are built from the inflows data registered by CNE and used as inputs on OSE2000 model[38]. For the dam and series power plants, the coefficient is established considering the yearly average projected generation of each power plant from years 2014 to 2024, for each hydrology pattern, according to OSE2000 outputs, in order to remove intra-year water transfers since this possibility is not considered in the work.

Additionally, the model considers a coefficient (called HDF) that indicates the energy over the total yearly inflow that each hydroelectric power plant should generate in each demand block, and reflects both the regulation capacity (or capacity of transferring water) of a facility to respond to peak demand, and the correlation between seasonality of water inflows and demand duration curve. The coefficients are presented on Table 6-7[39], considering that a plant without regulation capacity and a perfect correlation between inflows and demand would generate on each block the yearly energy percentage in

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[37] Compiled by author
[38] OSE2000 is a multi-node and multi-dam model based on stochastic dual dynamic programming for the optimal operation of the SIC
[39] Author's development

proportion to the duration of the demand block. For every single power plant the coefficient is established considering the projected generations of the plant on each demand block of the PLP[40] (averaged among hydrologies), which has 60 blocks over a year, more than the 9 demand blocks of the presented work. In that sense, a linear regression is made to relocate water generation projected by PLP on the corresponding demand blocks of the present work. Since run-of-river power plants have no regulation capacity, the coefficient only represents the correlation between water inflows to the plant and the demand, while both dam and series coefficients also capture their ability of transferring water among demand blocks.

[40] PLP is also a multi-node and multi-dam model based on stochastic dual dynamic programming for the optimal operation of the SIC, which has a better resolution than OSE2000

Table 6-1 - Hydroelectric power plants availability (HA)

Hydrology	Abanico	Alfalfal	Angostura	Antuco	Blanco	Canutillar	Capullo	Carena	CH_Bonito	CH_Callao	CH_Nalcas	CH_Rio_Huasco	Chacabuquito	Chacayes	Chiburgo
h_1	0.24	0.61	0.59	0.51	0.55	0.64	0.72	0.95	0.45	0.12	0.30	0.56	0.80	0.61	0.76
h_2	0.25	0.63	0.62	0.60	0.60	0.54	0.60	1.00	0.59	0.23	0.39	0.65	0.85	0.64	0.79
h_3	0.22	0.61	0.38	0.37	0.55	0.63	0.56	1.00	0.24	0.23	0.12	0.50	0.85	0.60	0.73
h_4	0.24	0.59	0.58	0.56	0.56	0.63	0.71	0.99	0.42	0.37	0.28	0.77	0.81	0.64	0.75
h_5	0.22	0.46	0.55	0.43	0.48	0.66	0.69	0.96	0.37	0.32	0.27	0.71	0.76	0.58	0.71
h_6	0.26	0.61	0.72	0.71	0.63	0.61	0.73	1.00	0.62	0.25	0.46	0.90	0.83	0.74	0.86
h_7	0.26	0.59	0.65	0.70	0.63	0.68	0.70	0.99	0.56	0.14	0.40	0.89	0.82	0.70	0.73
h_8	0.25	0.47	0.50	0.59	0.44	0.71	0.68	0.95	0.44	0.29	0.30	0.52	0.63	0.60	0.72
h_9	0.22	0.35	0.39	0.32	0.33	0.76	0.65	0.95	0.26	0.25	0.15	0.32	0.50	0.44	0.67
h_10	0.25	0.46	0.64	0.66	0.51	0.73	0.70	0.94	0.53	0.26	0.36	0.30	0.62	0.59	0.73
h_11	0.23	0.43	0.55	0.56	0.52	0.73	0.74	0.95	0.43	0.36	0.30	0.25	0.72	0.55	0.75
h_12	0.24	0.51	0.65	0.64	0.51	0.73	0.70	0.90	0.47	0.25	0.31	0.21	0.70	0.60	0.74
h_13	0.28	0.61	0.69	0.75	0.67	0.64	0.68	0.89	0.62	0.20	0.45	0.73	0.87	0.77	0.95
h_14	0.26	0.61	0.52	0.63	0.68	0.71	0.66	0.90	0.46	0.29	0.31	0.71	0.89	0.71	0.71
h_15	0.23	0.58	0.49	0.54	0.63	0.61	0.62	0.90	0.37	0.22	0.23	0.43	0.91	0.70	0.74
h_16	0.26	0.46	0.64	0.67	0.53	0.67	0.80	0.91	0.52	0.33	0.35	0.34	0.75	0.62	0.74
h_17	0.24	0.45	0.52	0.51	0.50	0.59	0.66	0.98	0.38	0.42	0.26	0.32	0.72	0.59	0.75
h_18	0.27	0.61	0.69	0.69	0.67	0.70	0.75	0.98	0.59	0.32	0.41	0.74	0.87	0.71	0.83
h_19	0.30	0.64	0.59	0.71	0.60	0.66	0.65	0.96	0.46	0.58	0.43	0.68	0.88	0.72	0.83
h_20	0.29	0.59	0.60	0.64	0.59	0.74	0.69	0.97	0.39	0.51	0.40	0.74	0.83	0.69	0.86
h_21	0.33	0.66	0.66	0.73	0.72	0.67	0.68	0.90	0.57	0.47	0.50	0.72	0.97	0.82	0.90
h_22	0.28	0.53	0.58	0.63	0.60	0.67	0.66	0.95	0.48	0.35	0.40	0.84	0.82	0.70	0.82
h_23	0.29	0.66	0.66	0.72	0.76	0.59	0.67	0.99	0.51	0.40	0.48	0.70	0.93	0.82	0.88

h_24	0.27	0.70	0.46	0.59	0.66	0.58	0.67	0.98	0.36	0.51	0.32	0.99	0.89	0.68	0.73
h_25	0.25	0.64	0.61	0.61	0.67	0.56	0.69	0.99	0.46	0.56	0.46	0.99	0.86	0.69	0.77
h_26	0.26	0.60	0.51	0.60	0.61	0.70	0.63	0.98	0.50	0.45	0.43	0.89	0.86	0.63	0.71
h_27	0.26	0.67	0.62	0.68	0.75	0.61	0.65	1.00	0.54	0.30	0.46	0.89	0.94	0.73	0.88
h_28	0.25	0.75	0.54	0.62	0.76	0.53	0.69	1.00	0.43	0.39	0.37	0.99	0.94	0.74	0.81
h_29	0.23	0.61	0.43	0.51	0.57	0.56	0.59	1.00	0.29	0.44	0.25	0.91	0.81	0.61	0.74
h_30	0.22	0.62	0.44	0.40	0.54	0.51	0.63	0.98	0.41	0.40	0.37	0.81	0.77	0.65	0.75
h_31	0.23	0.55	0.48	0.46	0.45	0.64	0.71	0.99	0.44	0.48	0.38	0.61	0.68	0.60	0.73
h_32	0.24	0.53	0.60	0.60	0.65	0.62	0.65	0.97	0.43	0.58	0.40	0.55	0.90	0.75	0.86
h_33	0.25	0.33	0.62	0.69	0.64	0.60	0.73	1.00	0.54	0.59	0.52	0.80	0.92	0.71	0.79
h_34	0.29	0.36	0.70	0.72	0.61	0.63	0.67	1.00	0.58	0.53	0.51	0.83	0.94	0.77	0.78
h_35	0.27	0.37	0.63	0.66	0.55	0.72	0.71	1.00	0.61	0.40	0.56	0.61	0.81	0.64	0.73
h_36	0.26	0.52	0.61	0.64	0.50	0.67	0.69	1.00	0.53	0.58	0.47	0.52	0.77	0.49	0.83
h_37	0.22	0.39	0.31	0.40	0.33	0.72	0.78	0.95	0.40	0.26	0.35	0.30	0.55	0.42	0.71
h_38	0.29	0.47	0.65	0.61	0.62	0.49	0.82	1.00	0.58	0.38	0.52	0.60	0.86	0.43	0.88
h_39	0.22	0.48	0.20	0.37	0.49	0.62	0.51	0.98	0.25	0.44	0.20	0.99	0.76	0.61	0.67
h_40	0.23	0.43	0.47	0.47	0.50	0.51	0.72	1.00	0.39	0.49	0.34	0.81	0.73	0.57	0.74
h_41	0.26	0.55	0.60	0.64	0.61	0.63	0.82	0.97	0.47	0.51	0.44	0.82	0.83	0.69	0.84
h_42	0.29	0.57	0.60	0.67	0.62	0.67	0.87	0.99	0.48	0.41	0.42	0.82	0.81	0.75	0.87
h_43	0.29	0.61	0.61	0.67	0.69	0.72	0.91	1.00	0.57	0.49	0.53	0.99	0.91	0.78	0.91
h_44	0.27	0.64	0.52	0.60	0.61	0.72	0.79	1.00	0.42	0.49	0.38	0.91	0.87	0.67	0.74
h_45	0.25	0.48	0.52	0.56	0.49	0.68	0.85	1.00	0.47	0.52	0.40	0.77	0.76	0.62	0.72
h_46	0.27	0.59	0.67	0.61	0.68	0.72	0.88	1.00	0.51	0.32	0.48	0.66	0.88	0.65	0.91
h_47	0.30	0.63	0.66	0.67	0.68	0.62	0.84	1.00	0.52	0.48	0.46	0.76	0.92	0.58	0.89
h_48	0.28	0.55	0.35	0.48	0.56	0.62	0.75	1.00	0.33	0.42	0.30	0.88	0.78	0.68	0.72
h_49	0.26	0.59	0.54	0.53	0.67	0.59	0.73	1.00	0.46	0.40	0.38	0.61	0.94	0.71	0.78
h_50	0.28	0.57	0.62	0.53	0.57	0.53	0.90	1.00	0.51	0.44	0.40	0.60	0.80	0.61	0.73
h_51	0.27	0.49	0.45	0.41	0.42	0.55	0.82	1.00	0.40	0.20	0.38	0.32	0.63	0.58	0.73

Table 6-2 - Hydroelectric power plants availability (HA)

Hydrology	Cipreses	Colbun	Confluencia	Coya-Pangal	Curillinque	Dongo	El_Manzano	El_Paso	El_Toro	Eyzaguirre	Florida	Guayacan	Hidroeléctrica_RM_01	Hidroeléctrica_RM_02	Hidroeléctrica_VI_Región_04
h_1	0.45	0.43	0.39	1.00	0.69	0.68	1.00	0.38	0.34	0.76	0.62	0.56	0.58	0.41	0.65
h_2	0.59	0.62	0.48	1.00	0.75	0.75	1.00	0.47	0.40	0.82	0.68	0.63	0.57	0.44	0.67
h_3	0.39	0.37	0.38	1.00	0.72	0.76	0.97	0.39	0.26	0.78	0.62	0.33	0.54	0.42	0.64
h_4	0.51	0.60	0.49	1.00	0.70	0.79	1.00	0.44	0.33	0.77	0.62	0.59	0.55	0.46	0.67
h_5	0.49	0.38	0.37	1.00	0.70	0.74	0.99	0.40	0.30	0.71	0.55	0.51	0.46	0.42	0.63
h_6	0.66	0.75	0.56	1.00	0.82	0.76	1.00	0.51	0.46	0.74	0.64	0.74	0.54	0.46	0.80
h_7	0.69	0.69	0.48	1.00	0.80	0.71	1.00	0.50	0.51	0.77	0.63	0.65	0.53	0.43	0.76
h_8	0.44	0.41	0.38	1.00	0.69	0.60	1.00	0.43	0.50	0.57	0.43	0.50	0.45	0.41	0.65
h_9	0.30	0.17	0.23	1.00	0.64	0.72	1.00	0.23	0.18	0.51	0.32	0.32	0.35	0.37	0.49
h_10	0.38	0.54	0.41	1.00	0.70	0.70	1.00	0.43	0.46	0.61	0.49	0.62	0.44	0.42	0.63
h_11	0.33	0.43	0.32	1.00	0.67	0.64	1.00	0.34	0.38	0.60	0.45	0.52	0.42	0.38	0.59
h_12	0.43	0.56	0.40	1.00	0.74	0.62	1.00	0.40	0.46	0.63	0.53	0.58	0.49	0.40	0.63
h_13	0.63	0.77	0.58	1.00	0.88	0.67	1.00	0.54	0.44	0.82	0.74	0.70	0.57	0.47	0.81
h_14	0.56	0.59	0.41	1.00	0.89	0.56	1.00	0.45	0.55	0.79	0.64	0.49	0.56	0.44	0.77
h_15	0.57	0.62	0.44	1.00	0.86	0.76	0.99	0.42	0.39	0.77	0.63	0.46	0.54	0.44	0.76
h_16	0.65	0.69	0.41	1.00	0.86	0.60	1.00	0.40	0.47	0.75	0.59	0.59	0.46	0.42	0.67
h_17	0.46	0.49	0.39	1.00	0.79	0.74	0.96	0.40	0.39	0.59	0.49	0.47	0.45	0.42	0.63
h_18	0.60	0.72	0.50	1.00	0.84	0.63	1.00	0.48	0.44	0.76	0.66	0.68	0.55	0.44	0.76
h_19	0.75	0.72	0.52	1.00	0.90	0.73	0.99	0.48	0.52	0.81	0.69	0.57	0.57	0.44	0.75
h_20	0.78	0.73	0.50	1.00	0.93	0.69	0.98	0.47	0.50	0.79	0.63	0.58	0.55	0.45	0.74
h_21	0.77	0.73	0.63	1.00	0.94	0.64	1.00	0.57	0.53	0.86	0.84	0.62	0.61	0.48	0.87

h_22	0.62	0.64	0.49	1.00	0.93	0.66	1.00	0.47	0.52	0.79	0.60	0.56	0.52	0.42	0.77
h_23	0.71	0.74	0.58	1.00	0.88	0.68	0.99	0.55	0.44	0.81	0.76	0.68	0.63	0.48	0.87
h_24	0.71	0.60	0.52	1.00	0.92	0.63	1.00	0.50	0.55	0.86	0.80	0.45	0.63	0.45	0.74
h_25	0.65	0.67	0.54	1.00	0.83	0.73	0.98	0.51	0.42	0.79	0.65	0.61	0.61	0.45	0.73
h_26	0.58	0.52	0.43	1.00	0.87	0.70	1.00	0.43	0.51	0.79	0.67	0.49	0.55	0.44	0.67
h_27	0.70	0.73	0.54	1.00	0.89	0.67	1.00	0.53	0.52	0.84	0.72	0.60	0.60	0.47	0.77
h_28	0.67	0.68	0.54	1.00	0.85	0.74	0.99	0.52	0.45	0.85	0.78	0.52	0.66	0.48	0.79
h_29	0.46	0.48	0.46	1.00	0.82	0.75	0.97	0.44	0.37	0.78	0.67	0.41	0.56	0.42	0.65
h_30	0.38	0.37	0.48	1.00	0.76	0.69	0.96	0.46	0.24	0.74	0.62	0.42	0.55	0.42	0.70
h_31	0.34	0.33	0.40	1.00	0.69	0.74	0.98	0.42	0.31	0.72	0.57	0.47	0.52	0.43	0.64
h_32	0.47	0.68	0.58	1.00	0.85	0.72	1.00	0.51	0.44	0.85	0.77	0.57	0.58	0.47	0.78
h_33	0.55	0.70	0.55	1.00	0.86	0.61	1.00	0.52	0.50	0.86	0.71	0.62	0.58	0.44	0.78
h_34	0.57	0.61	0.57	1.00	0.84	0.73	1.00	0.55	0.49	0.86	0.80	0.71	0.57	0.41	0.82
h_35	0.59	0.56	0.52	1.00	0.81	0.60	1.00	0.50	0.52	0.84	0.70	0.63	0.55	0.42	0.69
h_36	0.65	0.61	0.55	1.00	0.83	0.69	1.00	0.52	0.46	0.80	0.66	0.60	0.51	0.34	0.50
h_37	0.40	0.26	0.36	1.00	0.69	0.76	0.95	0.38	0.33	0.55	0.36	0.28	0.37	0.28	0.46
h_38	0.64	0.68	0.60	1.00	0.84	0.55	1.00	0.55	0.29	0.77	0.68	0.64	0.49	0.34	0.46
h_39	0.42	0.21	0.31	1.00	0.69	0.61	0.87	0.36	0.34	0.73	0.54	0.19	0.44	0.29	0.67
h_40	0.37	0.44	0.39	1.00	0.67	0.80	0.92	0.41	0.27	0.64	0.53	0.45	0.43	0.31	0.60
h_41	0.57	0.67	0.53	1.00	0.85	0.64	0.97	0.51	0.46	0.81	0.70	0.59	0.51	0.38	0.73
h_42	0.77	0.71	0.53	1.00	0.91	0.80	0.97	0.50	0.52	0.84	0.73	0.57	0.57	0.46	0.81
h_43	0.78	0.74	0.59	1.00	0.92	0.69	1.00	0.55	0.42	0.84	0.74	0.63	0.61	0.48	0.83
h_44	0.66	0.46	0.48	1.00	0.88	0.70	0.98	0.48	0.52	0.84	0.71	0.47	0.58	0.38	0.70
h_45	0.49	0.45	0.42	1.00	0.84	0.68	0.99	0.44	0.43	0.72	0.55	0.44	0.43	0.30	0.61
h_46	0.69	0.73	0.47	1.00	0.90	0.65	0.99	0.49	0.37	0.81	0.76	0.66	0.58	0.46	0.74
h_47	0.82	0.71	0.63	1.00	0.92	0.58	1.00	0.55	0.40	0.86	0.81	0.69	0.58	0.45	0.65
h_48	0.53	0.36	0.44	1.00	0.80	0.55	0.98	0.42	0.43	0.77	0.60	0.60	0.49	0.38	0.58
h_49	0.58	0.59	0.49	1.00	0.79	0.79	0.97	0.49	0.34	0.83	0.75	0.47	0.55	0.43	0.68
h_50	0.52	0.52	0.49	1.00	0.75	0.74	0.99	0.43	0.25	0.83	0.70	0.66	0.52	0.41	0.77
h_51	0.33	0.28	0.29	1.00	0.61	0.68	1.00	0.33	0.24	0.75	0.54	0.52	0.42	0.33	0.47

Table 6-3 - Hydroelectric power plants availability (HA)

Hydrology	Hidroeléctrica_VI_Región_05	Hidroeléctrica_VI_Región_06	Hidroeléctrica_VI_Región_07	Hidroeléctrica_VI_Región_08	Hidroeléctrica_VII_Región_01	Hidroeléctrica_VII_Región_02	Hidroeléctrica_VII_Región_04	Hidroeléctrica_VIII_Región_01	Hidroeléctrica_VIII_Región_02	Hidroeléctrica_VIII_Región_03	Hidroeléctrica_X_Región_03	Hornitos	Isla	Juncal	La_Arena
h_1	0.65	0.65	0.65	0.65	0.83	0.91	0.70	0.54	0.58	0.58	0.98	0.62	0.70	0.52	0.73
h_2	0.67	0.67	0.67	0.67	0.87	0.93	0.75	0.59	0.64	0.64	0.97	0.65	0.75	0.56	0.59
h_3	0.64	0.64	0.64	0.64	0.67	0.73	0.70	0.35	0.35	0.35	0.98	0.61	0.70	0.48	0.62
h_4	0.67	0.67	0.67	0.67	0.78	0.83	0.71	0.59	0.61	0.61	0.99	0.59	0.71	0.50	0.74
h_5	0.63	0.63	0.63	0.63	0.64	0.71	0.71	0.40	0.54	0.54	0.97	0.46	0.71	0.35	0.70
h_6	0.80	0.80	0.80	0.80	0.98	1.00	0.83	0.76	0.76	0.76	0.99	0.60	0.83	0.53	0.62
h_7	0.76	0.76	0.76	0.76	0.91	0.96	0.80	0.72	0.67	0.67	0.99	0.58	0.80	0.47	0.69
h_8	0.65	0.65	0.65	0.65	0.61	0.68	0.69	0.47	0.52	0.52	0.97	0.44	0.69	0.33	0.73
h_9	0.49	0.49	0.49	0.49	0.49	0.58	0.61	0.15	0.34	0.34	0.95	0.34	0.61	0.26	0.73
h_10	0.63	0.63	0.63	0.63	0.87	0.91	0.69	0.68	0.65	0.65	0.99	0.48	0.69	0.39	0.76
h_11	0.59	0.59	0.59	0.59	0.66	0.71	0.66	0.55	0.55	0.55	0.99	0.45	0.66	0.34	0.74
h_12	0.63	0.63	0.63	0.63	0.85	0.90	0.73	0.65	0.61	0.61	0.87	0.52	0.73	0.40	0.76
h_13	0.81	0.81	0.81	0.81	0.96	0.97	0.91	0.72	0.72	0.72	0.94	0.58	0.91	0.52	0.71
h_14	0.77	0.77	0.77	0.77	0.97	0.99	0.90	0.56	0.52	0.52	0.92	0.63	0.90	0.51	0.72
h_15	0.76	0.76	0.76	0.76	0.95	0.98	0.86	0.59	0.49	0.49	0.95	0.59	0.86	0.51	0.58
h_16	0.67	0.67	0.67	0.67	0.96	0.98	0.86	0.70	0.62	0.62	0.87	0.50	0.86	0.38	0.79
h_17	0.63	0.63	0.63	0.63	0.74	0.80	0.77	0.49	0.50	0.50	0.96	0.53	0.77	0.43	0.59
h_18	0.76	0.76	0.76	0.76	0.89	0.92	0.85	0.64	0.70	0.70	0.95	0.66	0.85	0.58	0.71
h_19	0.75	0.75	0.75	0.75	0.97	0.99	0.91	0.58	0.59	0.59	0.92	0.67	0.91	0.58	0.58
h_20	0.74	0.74	0.74	0.74	0.98	1.00	0.93	0.61	0.60	0.60	0.93	0.58	0.93	0.47	0.56
h_21	0.87	0.87	0.87	0.87	1.00	1.00	0.95	0.65	0.64	0.64	0.95	0.66	0.95	0.56	0.67

h_22	0.77	0.77	0.77	0.77	0.94	0.97	0.91	0.58	0.58	0.58	0.96	0.54	0.91	0.41	0.68
h_23	0.87	0.87	0.87	0.87	0.95	0.98	0.88	0.74	0.69	0.69	0.88	0.64	0.88	0.57	0.55
h_24	0.74	0.74	0.74	0.74	0.91	0.96	0.92	0.51	0.48	0.48	0.85	0.68	0.92	0.58	0.65
h_25	0.73	0.73	0.73	0.73	0.82	0.89	0.83	0.62	0.63	0.63	0.82	0.65	0.83	0.57	0.54
h_26	0.67	0.67	0.67	0.67	0.89	0.95	0.87	0.58	0.51	0.51	0.88	0.62	0.87	0.51	0.65
h_27	0.77	0.77	0.77	0.77	0.96	0.99	0.91	0.72	0.63	0.63	0.94	0.71	0.91	0.61	0.65
h_28	0.79	0.79	0.79	0.79	0.89	0.93	0.86	0.50	0.54	0.54	0.82	0.68	0.86	0.61	0.59
h_29	0.65	0.65	0.65	0.65	0.73	0.80	0.80	0.49	0.44	0.44	0.70	0.57	0.80	0.43	0.54
h_30	0.70	0.70	0.70	0.70	0.77	0.85	0.73	0.36	0.45	0.45	0.92	0.54	0.73	0.46	0.62
h_31	0.64	0.64	0.64	0.64	0.89	0.93	0.70	0.40	0.49	0.49	0.96	0.44	0.70	0.33	0.68
h_32	0.78	0.78	0.78	0.78	0.95	0.97	0.86	0.62	0.59	0.59	0.86	0.62	0.86	0.53	0.57
h_33	0.78	0.78	0.78	0.78	0.97	0.99	0.85	0.68	0.65	0.65	0.77	0.65	0.85	0.55	0.70
h_34	0.82	0.82	0.82	0.82	0.90	0.96	0.86	0.71	0.73	0.73	0.81	0.62	0.86	0.49	0.57
h_35	0.69	0.69	0.69	0.69	0.92	0.97	0.82	0.58	0.64	0.64	0.86	0.55	0.82	0.44	0.71
h_36	0.50	0.50	0.50	0.50	0.97	0.99	0.86	0.63	0.62	0.62	0.94	0.50	0.86	0.38	0.56
h_37	0.46	0.46	0.46	0.46	0.63	0.70	0.68	0.26	0.30	0.30	0.97	0.32	0.68	0.24	0.70
h_38	0.46	0.46	0.46	0.46	0.98	1.00	0.86	0.72	0.66	0.66	0.92	0.60	0.86	0.52	0.74
h_39	0.67	0.67	0.67	0.67	0.61	0.70	0.66	0.14	0.20	0.20	0.89	0.50	0.66	0.38	0.55
h_40	0.60	0.60	0.60	0.60	0.77	0.82	0.66	0.44	0.48	0.48	0.82	0.53	0.66	0.40	0.60
h_41	0.73	0.73	0.73	0.73	0.94	0.97	0.84	0.55	0.61	0.61	0.71	0.61	0.84	0.53	0.72
h_42	0.81	0.81	0.81	0.81	0.98	0.99	0.92	0.69	0.59	0.59	0.82	0.60	0.92	0.50	0.57
h_43	0.83	0.83	0.83	0.83	1.00	1.00	0.91	0.72	0.65	0.65	0.89	0.64	0.91	0.57	0.76
h_44	0.70	0.70	0.70	0.70	0.91	0.95	0.89	0.47	0.49	0.49	0.87	0.63	0.89	0.50	0.65
h_45	0.61	0.61	0.61	0.61	0.95	0.98	0.82	0.58	0.47	0.47	0.93	0.47	0.82	0.35	0.72
h_46	0.74	0.74	0.74	0.74	0.92	0.99	0.91	0.67	0.68	0.68	0.91	0.62	0.91	0.54	0.66
h_47	0.65	0.65	0.65	0.65	0.99	1.00	0.93	0.67	0.72	0.72	0.91	0.75	0.93	0.58	0.67
h_48	0.58	0.58	0.58	0.58	0.86	0.99	0.79	0.29	0.64	0.64	0.91	0.61	0.79	0.40	0.55
h_49	0.68	0.68	0.68	0.68	0.96	0.99	0.80	0.54	0.49	0.49	0.86	0.73	0.80	0.57	0.70
h_50	0.77	0.77	0.77	0.77	0.93	0.97	0.75	0.58	0.67	0.67	0.96	0.56	0.75	0.48	0.70
h_51	0.47	0.47	0.47	0.47	0.93	0.97	0.62	0.35	0.54	0.54	0.94	0.42	0.62	0.35	0.67

Table 6-4 - Hydroelectric power plants availability (HA)

Hydrology	La_Higuera	La_Paloma	Laja_I	Lican	Lircay	Loma_Alta	Los_Hierros	Los_Molles	Los_Morros	Los_Quilos	Machicura	Maitenes	Mallarauco	Mampil	Mariposas
h_1	0.49	0.26	0.52	0.67	0.74	0.71	0.76	0.23	1.00	0.79	0.44	0.47	0.97	0.63	0.76
h_2	0.58	0.24	0.58	0.61	0.77	0.76	0.76	0.28	1.00	0.84	0.64	0.47	1.00	0.59	0.81
h_3	0.47	0.13	0.39	0.55	0.70	0.74	0.71	0.20	1.00	0.83	0.38	0.47	0.89	0.54	0.72
h_4	0.56	0.26	0.57	0.81	0.77	0.72	0.75	0.41	0.99	0.80	0.62	0.47	0.99	0.70	0.80
h_5	0.47	0.43	0.44	0.78	0.70	0.73	0.74	0.30	1.00	0.74	0.38	0.46	0.72	0.73	0.75
h_6	0.68	0.57	0.66	0.70	0.77	0.83	0.76	0.50	0.99	0.82	0.77	0.47	1.00	0.54	0.81
h_7	0.61	0.66	0.65	0.83	0.77	0.82	0.76	0.39	1.00	0.81	0.71	0.47	1.00	0.53	0.81
h_8	0.46	0.60	0.66	0.67	0.72	0.71	0.71	0.20	0.88	0.62	0.43	0.45	0.76	0.72	0.74
h_9	0.27	0.40	0.37	0.74	0.60	0.65	0.60	0.13	0.76	0.49	0.18	0.39	0.50	0.47	0.62
h_10	0.50	0.16	0.60	0.74	0.72	0.72	0.72	0.12	0.86	0.61	0.56	0.39	0.83	0.79	0.76
h_11	0.40	0.03	0.55	0.79	0.73	0.69	0.70	0.11	0.93	0.71	0.44	0.45	0.73	0.78	0.77
h_12	0.49	0.03	0.57	0.75	0.74	0.75	0.73	0.11	0.91	0.69	0.57	0.45	0.91	0.58	0.77
h_13	0.71	0.31	0.63	0.67	0.77	0.87	0.73	0.46	1.00	0.86	0.80	0.48	1.00	0.69	0.81
h_14	0.50	0.53	0.57	0.72	0.74	0.89	0.76	0.21	1.00	0.88	0.60	0.47	1.00	0.56	0.79
h_15	0.52	0.38	0.57	0.56	0.76	0.87	0.73	0.15	1.00	0.91	0.64	0.47	1.00	0.50	0.81
h_16	0.50	0.13	0.57	0.74	0.76	0.86	0.70	0.14	1.00	0.74	0.71	0.46	1.00	0.53	0.80
h_17	0.47	0.13	0.50	0.71	0.74	0.81	0.58	0.13	0.91	0.71	0.50	0.45	0.92	0.58	0.78
h_18	0.62	0.17	0.63	0.74	0.77	0.84	0.64	0.32	1.00	0.86	0.75	0.47	1.00	0.62	0.80
h_19	0.63	0.45	0.56	0.62	0.76	0.89	0.73	0.48	1.00	0.87	0.74	0.47	1.00	0.69	0.81
h_20	0.60	0.52	0.49	0.80	0.77	0.91	0.72	0.20	1.00	0.81	0.76	0.47	1.00	0.53	0.81
h_21	0.79	0.55	0.62	0.80	0.75	0.91	0.76	0.43	1.00	0.96	0.75	0.47	1.00	0.54	0.81

h_22	0.61	0.56	0.54	0.72	0.75	0.90	0.74	0.23	1.00	0.80	0.64	0.46	0.96	0.37	0.79
h_23	0.71	0.63	0.63	0.65	0.77	0.86	0.76	0.44	0.99	0.92	0.77	0.48	1.00	0.55	0.81
h_24	0.61	0.86	0.50	0.55	0.75	0.91	0.76	0.48	1.00	0.88	0.61	0.48	1.00	0.49	0.77
h_25	0.65	0.86	0.61	0.73	0.77	0.84	0.73	0.57	0.99	0.85	0.69	0.48	1.00	0.67	0.81
h_26	0.52	0.86	0.59	0.75	0.70	0.88	0.76	0.27	0.99	0.84	0.52	0.47	1.00	0.59	0.77
h_27	0.66	0.55	0.58	0.76	0.77	0.87	0.76	0.24	0.99	0.94	0.76	0.48	1.00	0.49	0.81
h_28	0.66	0.74	0.52	0.68	0.77	0.86	0.76	0.55	0.99	0.94	0.70	0.52	1.00	0.28	0.80
h_29	0.53	0.85	0.53	0.57	0.72	0.83	0.75	0.27	0.98	0.80	0.49	0.52	1.00	0.61	0.75
h_30	0.59	0.58	0.41	0.56	0.68	0.78	0.73	0.21	0.86	0.76	0.38	0.50	1.00	0.49	0.73
h_31	0.50	0.49	0.38	0.64	0.70	0.71	0.67	0.20	0.87	0.67	0.34	0.46	1.00	0.54	0.69
h_32	0.73	0.49	0.43	0.79	0.76	0.85	0.75	0.38	0.94	0.89	0.71	0.53	1.00	0.70	0.79
h_33	0.67	0.69	0.54	0.69	0.77	0.86	0.76	0.51	0.99	0.90	0.72	0.52	1.00	0.49	0.81
h_34	0.69	0.83	0.61	0.54	0.76	0.86	0.76	0.27	1.00	0.93	0.61	0.49	1.00	0.43	0.79
h_35	0.64	0.55	0.53	0.70	0.74	0.83	0.76	0.21	1.00	0.80	0.55	0.51	1.00	0.55	0.78
h_36	0.64	0.37	0.57	0.64	0.75	0.83	0.76	0.13	0.99	0.75	0.63	0.50	1.00	0.43	0.79
h_37	0.45	0.09	0.53	0.76	0.63	0.70	0.75	0.12	0.70	0.54	0.27	0.44	0.94	0.59	0.71
h_38	0.74	0.59	0.56	0.71	0.77	0.82	0.76	0.54	0.92	0.85	0.71	0.46	1.00	0.37	0.81
h_39	0.39	0.82	0.33	0.55	0.54	0.70	0.69	0.33	0.87	0.75	0.21	0.46	1.00	0.21	0.62
h_40	0.49	0.52	0.35	0.69	0.72	0.68	0.71	0.21	0.79	0.72	0.45	0.43	1.00	0.40	0.75
h_41	0.63	0.53	0.48	0.85	0.77	0.84	0.73	0.35	0.97	0.82	0.70	0.49	1.00	0.40	0.81
h_42	0.63	0.60	0.45	0.61	0.76	0.89	0.76	0.35	1.00	0.80	0.74	0.46	1.00	0.45	0.79
h_43	0.71	0.90	0.63	0.81	0.77	0.89	0.76	0.64	0.99	0.90	0.78	0.51	1.00	0.52	0.81
h_44	0.57	0.82	0.53	0.71	0.72	0.88	0.76	0.38	0.98	0.85	0.46	0.50	1.00	0.36	0.74
h_45	0.50	0.56	0.50	0.71	0.72	0.85	0.76	0.23	0.98	0.74	0.46	0.49	1.00	0.40	0.77
h_46	0.61	0.55	0.49	0.76	0.76	0.87	0.80	0.44	0.97	0.87	0.77	0.50	1.00	0.47	0.80
h_47	0.79	0.46	0.49	0.70	0.73	0.90	0.80	0.31	1.00	0.91	0.73	0.49	1.00	0.48	0.77
h_48	0.55	0.47	0.44	0.82	0.74	0.82	0.56	0.37	0.98	0.77	0.36	0.49	1.00	0.28	0.77
h_49	0.60	0.41	0.49	0.83	0.76	0.80	0.65	0.42	0.95	0.94	0.60	0.51	1.00	0.39	0.79
h_50	0.59	0.40	0.49	0.85	0.74	0.76	0.69	0.23	0.99	0.77	0.52	0.48	1.00	0.44	0.78
h_51	0.37	0.16	0.39	0.71	0.74	0.63	0.53	0.16	0.95	0.61	0.28	0.49	0.83	0.31	0.78

Table 6-5 - Hydroelectric power plants availability (HA)

Hydrology	Modulo_01	Neltume	Ojos_de_Agua	Palmucho	Pangue	Pehuenche	Peuchen	Picoiquen	Pilmaiquen	Providencia	Puclaro	Pulelfu	Pullinque	Puntilla	Quilleco
h_1	0.79	0.45	0.83	0.94	0.51	0.45	0.65	0.61	0.88	0.53	0.34	0.22	0.55	0.75	0.63
h_2	0.75	0.47	0.85	0.94	0.62	0.57	0.61	0.58	0.80	0.54	0.15	0.43	0.59	0.74	0.70
h_3	0.78	0.23	0.84	0.93	0.31	0.38	0.56	0.39	0.63	0.51	0.25	0.40	0.38	0.77	0.46
h_4	0.80	0.57	0.85	0.94	0.55	0.54	0.73	0.57	0.90	0.53	0.20	0.53	0.60	0.72	0.68
h_5	0.79	0.46	0.84	0.94	0.49	0.37	0.76	0.45	0.91	0.52	0.67	0.53	0.56	0.75	0.53
h_6	0.86	0.57	0.86	0.95	0.77	0.70	0.56	0.61	0.84	0.54	0.74	0.45	0.64	0.67	0.83
h_7	0.80	0.55	0.88	0.94	0.62	0.62	0.54	0.59	0.89	0.54	0.97	0.28	0.61	0.74	0.87
h_8	0.80	0.50	0.88	0.93	0.46	0.43	0.75	0.55	0.88	0.52	0.74	0.49	0.59	0.62	0.76
h_9	0.79	0.36	0.83	0.93	0.30	0.26	0.49	0.33	0.84	0.48	0.57	0.47	0.48	0.61	0.36
h_10	0.81	0.56	0.85	0.94	0.59	0.52	0.81	0.56	0.85	0.51	0.36	0.48	0.61	0.60	0.75
h_11	0.75	0.57	0.86	0.93	0.48	0.43	0.81	0.51	0.97	0.52	0.21	0.54	0.62	0.62	0.69
h_12	0.76	0.56	0.86	0.94	0.54	0.53	0.60	0.53	0.89	0.53	0.04	0.46	0.64	0.61	0.76
h_13	0.73	0.56	0.89	0.94	0.69	0.72	0.72	0.66	0.85	0.54	0.35	0.39	0.68	0.69	0.83
h_14	0.74	0.48	0.91	0.93	0.43	0.54	0.58	0.58	0.86	0.53	0.98	0.51	0.56	0.74	0.80
h_15	0.71	0.39	0.88	0.93	0.42	0.55	0.52	0.50	0.79	0.54	0.85	0.41	0.48	0.73	0.67
h_16	0.73	0.54	0.88	0.94	0.55	0.62	0.54	0.60	0.92	0.54	0.69	0.51	0.57	0.75	0.78
h_17	0.79	0.36	0.86	0.93	0.44	0.47	0.60	0.42	0.77	0.53	0.52	0.37	0.52	0.59	0.62
h_18	0.93	0.58	0.86	0.94	0.63	0.63	0.65	0.60	0.84	0.53	0.43	0.36	0.65	0.67	0.80
h_19	0.76	0.47	0.89	0.94	0.55	0.63	0.72	0.56	0.74	0.54	0.79	0.41	0.60	0.72	0.82
h_20	0.79	0.51	0.89	0.94	0.55	0.65	0.55	0.47	0.86	0.54	0.95	0.33	0.59	0.74	0.79
h_21	0.86	0.53	0.91	0.94	0.60	0.73	0.56	0.60	0.83	0.54	0.90	0.42	0.65	0.71	0.83

h_22	0.79	0.44	0.90	0.94	0.54	0.62	0.38	0.53	0.85	0.53	0.95	0.27	0.55	0.78	0.75
h_23	0.72	0.56	0.85	0.94	0.66	0.70	0.58	0.57	0.85	0.54	0.83	0.41	0.60	0.66	0.82
h_24	0.72	0.39	0.91	0.93	0.43	0.56	0.50	0.47	0.82	0.53	1.00	0.36	0.46	0.72	0.75
h_25	0.67	0.55	0.86	0.94	0.60	0.60	0.69	0.65	0.89	0.54	1.00	0.37	0.59	0.70	0.75
h_26	0.75	0.40	0.86	0.93	0.44	0.52	0.60	0.54	0.84	0.52	0.98	0.30	0.56	0.74	0.75
h_27	0.75	0.54	0.90	0.94	0.57	0.68	0.50	0.58	0.85	0.54	0.86	0.21	0.61	0.73	0.81
h_28	0.68	0.38	0.89	0.94	0.50	0.60	0.29	0.43	0.85	0.54	0.97	0.32	0.53	0.69	0.76
h_29	0.59	0.24	0.87	0.93	0.38	0.48	0.64	0.37	0.79	0.51	0.98	0.31	0.39	0.74	0.64
h_30	0.75	0.29	0.84	0.93	0.42	0.40	0.51	0.42	0.82	0.51	0.83	0.34	0.41	0.68	0.48
h_31	0.85	0.40	0.84	0.93	0.45	0.37	0.56	0.56	0.86	0.50	0.74	0.45	0.53	0.74	0.57
h_32	0.71	0.43	0.92	0.94	0.53	0.64	0.73	0.57	0.90	0.53	0.64	0.43	0.52	0.73	0.70
h_33	0.70	0.49	0.91	0.94	0.61	0.63	0.51	0.59	0.95	0.54	0.84	0.47	0.59	0.74	0.79
h_34	0.73	0.57	0.90	0.95	0.71	0.60	0.44	0.60	0.89	0.53	0.96	0.39	0.64	0.75	0.83
h_35	0.74	0.56	0.87	0.94	0.61	0.54	0.57	0.53	0.92	0.53	0.82	0.29	0.61	0.76	0.81
h_36	0.72	0.46	0.87	0.94	0.59	0.57	0.44	0.54	0.88	0.53	0.71	0.44	0.56	0.77	0.78
h_37	0.83	0.23	0.85	0.93	0.28	0.31	0.61	0.32	0.83	0.51	0.31	0.15	0.37	0.63	0.49
h_38	0.78	0.56	0.87	0.94	0.63	0.64	0.45	0.63	0.90	0.54	0.50	0.28	0.67	0.67	0.75
h_39	0.80	0.11	0.88	0.93	0.19	0.26	0.26	0.30	0.54	0.48	0.99	0.39	0.28	0.77	0.46
h_40	0.61	0.33	0.84	0.93	0.45	0.43	0.49	0.45	0.77	0.50	0.85	0.35	0.44	0.62	0.57
h_41	0.63	0.47	0.87	0.94	0.58	0.60	0.48	0.54	0.93	0.54	0.73	0.46	0.56	0.71	0.74
h_42	0.66	0.39	0.88	0.94	0.60	0.66	0.46	0.52	0.75	0.53	0.74	0.32	0.53	0.74	0.80
h_43	0.80	0.58	0.89	0.94	0.61	0.67	0.53	0.60	0.94	0.54	0.85	0.33	0.64	0.72	0.83
h_44	0.80	0.38	0.89	0.94	0.50	0.47	0.37	0.45	0.84	0.52	1.00	0.41	0.55	0.76	0.76
h_45	0.84	0.36	0.85	0.93	0.48	0.48	0.41	0.45	0.91	0.53	0.94	0.38	0.53	0.74	0.70
h_46	0.80	0.52	0.88	0.94	0.64	0.67	0.48	0.54	0.92	0.54	0.81	0.25	0.63	0.67	0.73
h_47	0.80	0.48	0.92	0.94	0.62	0.65	0.49	0.52	0.92	0.53	0.97	0.31	0.62	0.72	0.79
h_48	0.75	0.30	0.86	0.93	0.32	0.39	0.29	0.16	0.81	0.53	0.96	0.47	0.43	0.78	0.62
h_49	0.75	0.40	0.86	0.93	0.48	0.53	0.39	0.21	0.78	0.53	0.96	0.47	0.51	0.74	0.67
h_50	0.83	0.45	0.84	0.94	0.57	0.53	0.43	0.25	0.96	0.53	0.75	0.10	0.58	0.76	0.67
h_51	0.76	0.46	0.89	0.93	0.40	0.32	0.27	0.25	0.86	0.51	0.44	0.59	0.47	0.80	0.51

Table 6-6 - Hydroelectric power plants availability (HA)

Hydrology	Ralco	Rapel	Rio_Trueno	Rucatayo	Rucue	San_Andres	San_Clemente	San_Ignacio	San_Pedro	Sauce_Andes	Sauzal	Volcan
h_1	0.47	0.20	0.62	0.59	0.60	0.41	1.00	0.45	0.76	0.77	0.56	0.85
h_2	0.52	0.38	0.58	0.61	0.67	0.47	1.00	0.73	0.76	0.82	0.58	0.89
h_3	0.28	0.19	0.41	0.39	0.44	0.41	0.99	0.35	0.61	0.85	0.56	0.87
h_4	0.48	0.49	0.66	0.64	0.65	0.43	0.97	0.71	0.83	0.83	0.62	0.84
h_5	0.47	0.16	0.70	0.58	0.50	0.39	0.97	0.36	0.82	0.69	0.56	0.88
h_6	0.64	0.50	0.78	0.65	0.79	0.52	1.00	0.84	0.81	0.81	0.71	0.89
h_7	0.59	0.46	0.75	0.69	0.82	0.50	0.98	0.80	0.86	0.80	0.68	0.90
h_8	0.43	0.21	0.60	0.64	0.72	0.40	0.97	0.43	0.80	0.63	0.59	0.81
h_9	0.26	0.05	0.62	0.57	0.34	0.28	0.97	0.08	0.74	0.50	0.43	0.68
h_10	0.56	0.23	0.62	0.68	0.72	0.39	0.98	0.61	0.78	0.96	0.58	0.73
h_11	0.46	0.17	0.63	0.72	0.66	0.37	0.97	0.44	0.86	0.96	0.55	0.78
h_12	0.52	0.26	0.65	0.72	0.72	0.41	0.98	0.63	0.86	0.92	0.58	0.77
h_13	0.59	0.65	0.64	0.68	0.79	0.52	1.00	0.88	0.80	0.91	0.74	0.91
h_14	0.42	0.31	0.61	0.63	0.76	0.42	0.99	0.66	0.75	0.80	0.66	0.89
h_15	0.39	0.42	0.52	0.56	0.63	0.42	0.98	0.72	0.71	0.95	0.70	0.86
h_16	0.52	0.29	0.69	0.66	0.74	0.40	1.00	0.78	0.84	0.96	0.61	0.81
h_17	0.43	0.20	0.56	0.57	0.59	0.41	0.97	0.52	0.67	0.92	0.58	0.79
h_18	0.59	0.45	0.67	0.70	0.76	0.49	0.99	0.84	0.78	0.83	0.69	0.89
h_19	0.51	0.46	0.58	0.59	0.78	0.47	0.99	0.82	0.70	0.98	0.67	0.90
h_20	0.52	0.35	0.70	0.67	0.75	0.45	0.98	0.84	0.77	0.95	0.66	0.88
h_21	0.55	0.55	0.64	0.66	0.78	0.55	1.00	0.79	0.78	0.99	0.76	0.94

h_22	0.51	0.30	0.54	0.63	0.71	0.46	1.00	0.67	0.70	1.00	0.66	0.83
h_23	0.57	0.66	0.59	0.65	0.78	0.53	0.99	0.87	0.74	1.00	0.69	0.81
h_24	0.43	0.33	0.53	0.52	0.72	0.48	0.97	0.64	0.71	1.00	0.70	0.82
h_25	0.54	0.48	0.64	0.60	0.71	0.47	0.98	0.77	0.81	1.00	0.70	0.79
h_26	0.45	0.20	0.61	0.62	0.71	0.41	0.98	0.54	0.75	1.00	0.63	0.82
h_27	0.54	0.44	0.66	0.62	0.77	0.49	1.00	0.83	0.77	1.00	0.69	0.80
h_28	0.48	0.48	0.56	0.58	0.72	0.53	0.98	0.75	0.68	1.00	0.71	0.82
h_29	0.35	0.17	0.51	0.47	0.61	0.42	0.97	0.51	0.60	1.00	0.62	0.80
h_30	0.38	0.21	0.50	0.52	0.46	0.45	0.97	0.34	0.62	0.94	0.66	0.75
h_31	0.41	0.13	0.64	0.63	0.54	0.41	0.97	0.29	0.74	0.91	0.60	0.75
h_32	0.51	0.40	0.65	0.61	0.66	0.49	1.00	0.75	0.76	1.00	0.79	0.62
h_33	0.59	0.46	0.72	0.65	0.75	0.52	0.99	0.79	0.79	1.00	0.79	0.84
h_34	0.62	0.38	0.67	0.67	0.79	0.52	1.00	0.63	0.77	1.00	0.70	0.85
h_35	0.56	0.31	0.67	0.69	0.77	0.49	0.99	0.57	0.78	1.00	0.71	0.85
h_36	0.54	0.30	0.60	0.62	0.74	0.51	0.98	0.67	0.71	1.00	0.72	0.88
h_37	0.24	0.11	0.52	0.49	0.47	0.37	0.97	0.19	0.60	0.89	0.52	0.76
h_38	0.54	0.56	0.68	0.68	0.71	0.55	0.99	0.78	0.78	0.96	0.75	0.78
h_39	0.14	0.08	0.29	0.31	0.43	0.36	0.97	0.12	0.40	0.98	0.57	0.85
h_40	0.39	0.21	0.45	0.50	0.54	0.41	0.97	0.48	0.61	0.92	0.58	0.76
h_41	0.52	0.47	0.56	0.65	0.70	0.48	0.99	0.78	0.75	0.99	0.75	0.85
h_42	0.52	0.43	0.46	0.54	0.75	0.49	1.00	0.79	0.63	1.00	0.77	0.88
h_43	0.50	0.54	0.66	0.71	0.79	0.54	0.99	0.84	0.83	1.00	0.82	0.89
h_44	0.48	0.24	0.53	0.56	0.72	0.47	1.00	0.44	0.73	0.93	0.72	0.91
h_45	0.47	0.25	0.58	0.53	0.66	0.44	1.00	0.46	0.81	0.97	0.69	0.88
h_46	0.58	0.53	0.61	0.61	0.70	0.49	1.00	0.85	0.81	1.00	0.81	0.92
h_47	0.53	0.42	0.60	0.57	0.75	0.49	1.00	0.79	0.72	1.00	0.80	0.88
h_48	0.26	0.13	0.51	0.49	0.59	0.38	1.00	0.34	0.70	1.00	0.60	0.84
h_49	0.43	0.39	0.48	0.58	0.64	0.51	1.00	0.61	0.85	1.00	0.74	0.86
h_50	0.52	0.25	0.53	0.58	0.63	0.47	0.98	0.55	0.77	1.00	0.70	0.84
h_51	0.36	0.11	0.53	0.70	0.48	0.36	0.86	0.21	0.32	1.00	0.61	0.87

Table 6-7 - Hydroelectric power plants peaking capacity (HDF), Commissioning Date and Real Power

Hydroelectric Power Plant	HDF Block 1	HDF Block 2	HDF Block 3	HDF Block 4	HDF Block 5	HDF Block 6	HDF Block 7	HDF Block 8	HDF Block 9	Commissioning Date	Real Power (MW)
HDF proportional to block duration	12%	11%	15%	13%	10%	12%	11%	11%	4%		
Abanico	12%	11%	15%	13%	10%	12%	11%	11%	4%		136
Alfalfal	13%	12%	15%	13%	10%	11%	11%	11%	4%		196
Angostura	16%	14%	17%	13%	10%	10%	9%	8%	3%	Dec-13	316
Antuco	14%	12%	16%	13%	10%	11%	11%	10%	4%		320
Blanco	13%	12%	15%	13%	10%	11%	11%	11%	4%		57
Canutillar	18%	15%	18%	13%	10%	10%	8%	7%	2%		170
Capullo	12%	11%	15%	13%	10%	12%	11%	11%	4%		10
Carena	12%	11%	15%	13%	10%	12%	11%	11%	4%		9
CH_Bonito	12%	11%	15%	13%	10%	12%	12%	11%	4%	May-13	12
CH_Callao	12%	11%	15%	13%	10%	12%	12%	11%	4%		3
CH_Nalcas	12%	11%	15%	13%	10%	12%	11%	11%	4%		8
CH_Rio_Huasco	13%	11%	15%	13%	10%	12%	11%	11%	4%	Apr-13	4
Chacabuquito	13%	11%	15%	13%	10%	12%	11%	11%	4%		25
Chacayes	13%	12%	15%	13%	10%	12%	11%	11%	4%		106
Chiburgo	13%	12%	15%	13%	10%	12%	11%	11%	4%		19
Cipreses	17%	14%	17%	13%	10%	10%	9%	7%	2%		105
Colbun	17%	14%	17%	13%	10%	10%	9%	8%	3%		457
Confluencia	13%	12%	15%	13%	10%	11%	11%	10%	4%		159

Coya-Pangal	12%	11%	15%	13%	10%	12%	11%	11%	4%		11
Curillinque	14%	12%	16%	13%	10%	11%	11%	10%	4%		89
Dongo	12%	11%	15%	13%	10%	12%	12%	11%	4%		6
El_Manzano	12%	11%	15%	13%	10%	12%	11%	11%	4%		5
El_Paso	13%	12%	15%	13%	10%	11%	11%	10%	4%	Jul-13	60
El_Toro	17%	15%	18%	13%	10%	10%	8%	7%	2%		450
Eyzaguirre	13%	11%	15%	13%	10%	12%	11%	11%	4%		2
Florida	13%	11%	15%	13%	10%	12%	11%	11%	4%		28
Guayacan	12%	11%	15%	13%	10%	12%	12%	11%	4%		12
Hidroeléctrica_RM_01	13%	12%	15%	13%	10%	11%	11%	10%	4%	May-17	256
Hidroeléctrica_RM_02	13%	12%	16%	13%	10%	11%	11%	10%	4%	Sep-17	275
Hidroeléctrica_VI_Región_04	13%	12%	15%	13%	10%	12%	11%	11%	4%	Dec-17	180
Hidroeléctrica_VI_Región_05	13%	12%	15%	13%	10%	12%	11%	11%	4%	Dec-17	110
Hidroeléctrica_VI_Región_06	13%	12%	15%	13%	10%	12%	11%	11%	4%	Dec-17	155
Hidroeléctrica_VI_Región_07	13%	12%	15%	13%	10%	12%	11%	11%	4%	Dec-17	80
Hidroeléctrica_VI_Región_08	13%	12%	15%	13%	10%	12%	11%	11%	4%	Dec-17	30
Hidroeléctrica_VII_Región_01	12%	11%	15%	13%	10%	12%	11%	11%	4%	Jun-15	30
Hidroeléctrica_VII_Región_02	12%	11%	15%	13%	10%	12%	11%	11%	4%	Oct-19	20
Hidroeléctrica_VII_Región_04	14%	12%	16%	13%	10%	11%	11%	10%	4%	Dec-15	150
Hidroeléctrica_VIII_Región_01	12%	11%	15%	13%	10%	12%	12%	11%	4%	Jan-17	136
Hidroeléctrica_VIII_Región_02	12%	11%	15%	13%	10%	12%	12%	11%	4%	Nov-15	20
Hidroeléctrica_VIII_Región_03	12%	11%	15%	13%	10%	12%	12%	11%	4%	Mar-21	20
Hidroeléctrica_X_Región_03	12%	11%	15%	13%	10%	12%	11%	11%	4%	Dec-15	7
Hornitos	13%	12%	15%	13%	10%	11%	11%	11%	4%		55
Isla	14%	12%	16%	13%	10%	11%	11%	10%	4%		68
Juncal	13%	12%	15%	13%	10%	11%	11%	11%	4%		32
La_Arena	12%	11%	15%	13%	10%	12%	11%	11%	4%		3

La_Higuera	13%	12%	15%	13%	10%	11%	11%	11%	4%		153
La_Paloma	12%	11%	15%	13%	10%	12%	11%	11%	4%		5
Laja_I	12%	11%	15%	13%	10%	12%	12%	11%	4%	Aug-13	37
Lican	12%	11%	15%	13%	10%	12%	12%	11%	4%		17
Lircay	12%	11%	15%	13%	10%	12%	11%	11%	4%		19
Loma_Alta	14%	12%	16%	13%	10%	11%	11%	10%	4%		38
Los_Hierros	12%	11%	15%	13%	10%	12%	12%	11%	4%	Jun-13	25
Los_Molles	12%	11%	15%	13%	10%	12%	11%	11%	4%		19
Los_Morros	13%	11%	15%	13%	10%	12%	11%	11%	4%		2
Los_Quilos	13%	11%	15%	13%	10%	12%	11%	11%	4%		40
Machicura	16%	14%	17%	13%	10%	10%	9%	8%	3%		97
Maitenes	12%	11%	15%	13%	10%	12%	11%	11%	4%		31
Mallarauco	12%	11%	15%	13%	10%	12%	11%	11%	4%		3
Mampil	13%	11%	15%	13%	10%	12%	11%	11%	4%		49
Mariposas	12%	11%	15%	13%	10%	12%	11%	11%	4%		6
Modulo_01	13%	11%	15%	13%	10%	12%	11%	11%	4%	Apr-21	660
Neltume	12%	11%	15%	13%	10%	12%	12%	11%	4%	Dec-17	473
Ojos_de_Agua	13%	11%	15%	13%	10%	12%	11%	11%	4%		9
Palmucho	13%	12%	15%	13%	10%	12%	11%	11%	4%		32
Pangue	18%	15%	18%	13%	10%	10%	8%	7%	2%		472
Pehuenche	15%	13%	16%	13%	10%	11%	10%	9%	3%		560
Peuchen	13%	11%	15%	13%	10%	12%	11%	11%	4%		77
Picoiquen	12%	11%	15%	13%	10%	12%	12%	11%	4%	Oct-13	19
Pilmaiquen	12%	11%	15%	13%	10%	12%	11%	11%	4%		35
Providencia	12%	11%	15%	13%	10%	12%	12%	11%	4%		13
Puclaro	13%	11%	15%	13%	10%	12%	11%	11%	4%		6
Pulelfu	12%	11%	15%	13%	10%	12%	11%	11%	4%	Sep-13	9

Pullinque	12%	11%	15%	13%	10%	12%	11%	11%	4%		49
Puntilla	12%	11%	15%	13%	10%	12%	11%	11%	4%		22
Quilleco	14%	12%	16%	13%	10%	11%	11%	10%	4%		70
Ralco	18%	15%	18%	13%	10%	9%	8%	6%	2%		690
Rapel	20%	16%	19%	14%	9%	9%	7%	5%	1%		375
Rio_Trueno	12%	11%	15%	13%	10%	12%	12%	11%	4%		6
Rucatayo	12%	11%	15%	13%	10%	12%	11%	11%	4%		60
Rucue	14%	12%	16%	13%	10%	11%	11%	10%	4%		178
San_Andres	13%	12%	16%	13%	10%	11%	11%	10%	4%	Jul-13	40
San_Clemente	12%	11%	15%	13%	10%	12%	11%	11%	4%		5
San_Ignacio	17%	15%	18%	13%	10%	10%	8%	7%	2%		37
San_Pedro	12%	11%	15%	13%	10%	12%	11%	11%	4%	Jan-17	144
Sauce_Andes	13%	11%	15%	13%	10%	12%	11%	11%	4%		1
Sauzal	13%	11%	15%	13%	10%	12%	11%	11%	4%		90
Volcan	12%	11%	15%	13%	10%	12%	11%	11%	4%		63

APPENDIX C: Un-hedged margin of Hydroelectric Park considering two levels of CO_2 emission taxes

Figure 6-3 refers to the sensitivity to a CO_2 emissions tax. It shows the un-hedged margin of the whole Hydro-Park considering two levels of taxes, making evident that a more variable un-hedged margin means a greatest level of hedging to achieve minimal result's variations.

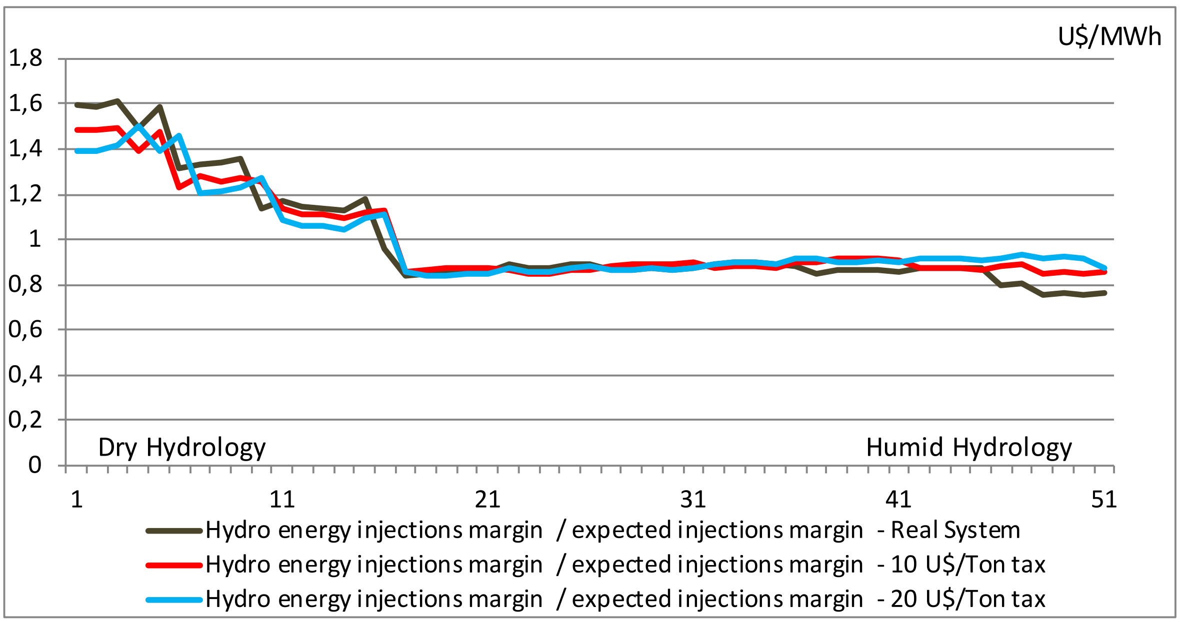

Figure 6-3 - By reason of the change of the spot price and its impact of over the injections margin of hydroelectric park, the un-hedged margin under 10U$/Ton CO2 taxes has a 25% less of variability than when no taxes. Under 20US$/Ton CO2 taxes, the variability decreases a 27%. This is the cause of less hydroelectric commitment under studied taxes[41].

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[41] The yearly margin on every one of the 51 hydrologies is, solely for the purpose of this presentation, divided by the expected injections margin of hydroelectric park on each tax case.