PONTIFICIA UNIVERSIDAD CATOLICA DE CHILE
ESCUELA DE INGENIERIA

WIND ENERGY GENERATION FEASIBILITY ON THE NORTHERN INTERCONNECTED SYSTEM (SING)

MARIO A. PAVEZ OVALLE

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

Advisor:
HUGH RUDNICK VAN DE WYNGARD

Santiago de Chile, January 2008

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To Mum, Dad, Carolina, Francisco, and all my friends and family for their unconditional support

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LIST OF ACRONYMS

CDEC	:	Centro de Despacho Económico de Carga (Economical Load Dispatch Center)
CDM	:	Clean Development Mechanism
CER	:	Certified Emission Reduction
CNE	:	Comisión Nacional de Energía (National Energy Commission)
COP	:	Conference of Parties
EF	:	Emission Factor
EU	:	European Union
FCCC	:	Framework Convention on Climate Change
FP	:	Firm Power
FWCC	:	First World Climate Conference
GHG	:	Greenhouse Gas
GWP	:	Global Warming Potential
IEA	:	International Energy Agency
IET	:	International Emission Trading
IP	:	Initial Power
IPCC	:	Intergovernmental Panel on Climate Change
IRR	:	Internal Rate of Return
JI	:	Joint Implementation
LDC	:	Load Duration Curve
LHV	:	Lower Heating Value

LOLP	:	Lost of Load Probability
MMA	:	McLennan Magasanik Associates
MRET	:	Mandatory Renewable Energy Target
NCRE	:	Non Conventional Renewable Energy
NEA	:	Nuclear Energy Agency
NEM	:	National Electricity Market
NEMMCO	:	National Electricity Market Managing Company
NPV	:	Net Present Value
ODS	:	Ozone Depleting Substances
OECD	:	Organization for Economic Cooperation and Development
PFP	:	Preliminary Firm Power
RE	:	Renewable Energy
REC	:	Renewable Energy Certificate
SC	:	Specific Consumption
SIC	:	Sistema Interconectado Central (Central Interconnected System)
SING	:	Sistema Interconectado del Norte Grande (Northern Interconnected System)
SRES	:	Special Report on Emission Scenarios
UN	:	United Nations
UNFCCC	:	United Nations Framework Convention on Climate Change
WCP	:	World Climate Programme
WMO	:	World Meteorological Organization
WP	:	Wind Project

ABSTRACT

The main objective of this thesis is to analyze the renewable energy installation feasibility, specifically the inclusion of wind energy at the Northern Interconnected System (SING). As a specific objective there is the modification of a dispatch model to make it capable of including non-conventional renewable energy (NCRE) into its calculations. Also, a method is proposed for calculating the firm capacity of NCRE, as well as developing a general technique for estimating the emission displacement. Thus apply these to a wind farm project. With all this, it is possible to perform an economic feasibility analysis for the investment of wind energy generation in the SING, followed by an analysis of the modifications done to the law regarding NCRE.

From the simulations, it was possible to see variations on the system marginal costs due to wind energy penetration only during the first 4 years, due to unadapted system characteristics. Also, the emission displacement methodology was applied. Taking the calculations and the estimation of firm capacity, the economic viability methodology was applied. After this, the applicability of the law modification was analyzed.

After all methodologies were applied, it is possible to conclude that the installation of wind farms is feasible only under a market that faces high enough prices, which means systems where expensive technologies are generating. It is also demonstrated that the law in this case generates enough incentives for the installation of wind farms.

In the case of having a coal adapted system, the electricity price is much lower, and this makes potential wind farm projects economically unfeasible. Moreover, on a market facing these prices, the law does not give adequate incentives for investing, this because the penalty imposed by law is not high enough.

RESUMEN

Esta tesis tiene como objetivo analizar la factibilidad de instalación de tecnologías renovables, específicamente la incorporación de energías eólicas en el Sistema Interconectado del Norte Grande (SING). Para alcanzar dicho objetivo se modifica un modelo de simulación de sistemas eléctricos para la incorporación de generación con energías renovables no convencionales (ERNC). Asimismo, se propone una metodología de cálculo de esquema de pago por potencia para centrales eólicas en su incorporación en el SING y se desarrolla una metodología generalizada de desplazo de emisiones para ERNC, y aplicación de ésta para centrales eólicas. Luego se realiza un análisis de factibilidad económica de inversión en generación eólica en el SING y en seguida se analiza la aplicabilidad de las modificaciones realizadas a la ley eléctrica en el contexto de ERNC.

A partir de las simulaciones realizadas es posible identificar las variaciones de costos marginales del sistema dependiendo de la penetración eólica. Asimismo, se aplicó la metodología desarrollada para el desplazo de emisiones. Con ambos cálculos y la estimación de la potencia firme se aplicó la metodología de viabilidad económica. Luego de realizado esto, se analizó la aplicabilidad de las modificaciones a la ley.

Luego de aplicadas las metodologías indicadas, es posible concluir que la instalación de centrales eólicas es factible bajo un mercado en donde los precios son suficientemente altos, es decir para sistemas en donde existen tecnologías caras generando. En este caso la ley genera suficientes incentivos a la instalación de centrales eólicas.

En caso de tener un sistema adaptado a carbón, el precio de la electricidad es más bajo y hace que los potenciales proyectos eólicos no sean económicamente factibles. Asimismo, bajo este escenario de precios, la ley no genera incentivos a la inversión, esto debido a que la multa que ésta impone es muy baja.

1 INTRODUCTION

On the last decade, renewable energy inclusion has been a very important aspect of many electricity markets around the world. All this, aiming to reduce the amount of greenhouse gases (GHG) emitted in the planet. To achieve this, the world has undertaken several methodologies (i.e. Kyoto Protocol).

In the same initiative of GHG reduction and at the same time, increase the technology mixture and system security, Chile has developed modifications to the electrical law to foster the investments on non-conventional renewable energy technologies. For designing these law modifications, the Chilean government looked at the Australian electricity market and that is why it is briefly analyzed on this thesis.

1.1 Motivation

This thesis has been supported by BHP Billiton and therefore motivated by BHP Billiton's sustainable development objectives and the clear intentions of the Chilean government of including renewable energy technologies in the electricity market.

Therefore, the main intention of this thesis is to give an initial view of how viable is the inclusion of renewable energy technologies, specifically wind energy, in the Chilean electricity market. On developing countries, renewable energy technologies are a matter of new concern and an investigation where the inclusion of these technologies is considered comes with great importance.

Because BHP Billiton's mining installations are located in the northern part of Chile, this thesis will analyze the inclusion of wind energy in the Northern Interconnected System (SING). Hence, it analyzes the economic feasibility of a wind energy project.

1.2 Investigation Outline and Contributions

As mentioned before, this thesis will analyze the inclusion of a wind farm in the SING and examine the effects caused in the system as well as study the feasibility of installing this kind of technologies in the system. The feasibility analysis includes an economic feasibility analysis and, also analyses how effective the application of the law would be under circumstances of bilateral energy contracts and selling energy to the spot market.

1.2.1 Hypothesis

The thesis will aim at demonstrating that, despite the high costs of renewable energies, wind energy in particular; the energy situation at the SING has created better economic conditions that make it economically feasible the installation of wind generators in that system, supported by the regulatory changes being implemented.

1.2.2 Investigation Outline

To be able to study the inclusion of wind energy in the Chilean electricity market, this thesis will be separated into the following areas:

- **Overview of existing reality:** This part shows a global view of the world techniques to reduce greenhouse gas emissions to see what fosters the inclusion of renewable energy on different electricity markets around the world. Also, focusing on what motivated this investigation, the Australian electricity market is briefly analyzed. Finally, the Chilean electricity market is explained to be able to know where the wind energy is being included.
- **Methodologies and Initial Calculations:** In this part all the essential calculations for a wind energy inclusion are specified; calculations like:
    - Wind Resource

- Energy Generation Potential
- Wind Farm Firm Capacity
- Emission Displacement
- Energy Purchase Contract Price

Also, the methodologies used in the investigation are explained. Among the methodologies explained there are:

- Methodology to calculate the emission displacement produced by renewable energy technologies.
- Investment feasibility analysis methodology.
- Law modification effectiveness analysis methodology.

- **Simulation Results and Analysis:** Here all the methodologies are applied and results are analyzed. With this, it is possible to see the law applicability and the economic feasibility of a wind project development.

1.2.3 Investigation Contributions and Innovative Aspects

The main contribution made by this thesis is analyzing the inclusion of wind energy in the northern electricity market in Chile; this type of analysis has not been done before, covering the many aspects of wind energy inclusion in Chile. Along with this analysis, the applicability of proposed changes of the electricity law was studied; this revision is highly important at the moment in Chile, because of the discussions concerning these changes.

The main innovation in this thesis is the development of a global methodology to overview the wind inclusion feasibility in a thermal centrally dispatched power pool. Similar techniques has been used in other investigations but never applied to the Chilean electricity market. Important are also the developments to assess the economic feasibility analysis (including an emission reduction technique) and the law applicability.

2 OVERVIEW OF PRESENT CONDITIONS

2.1 *World View of Greenhouse Gas Emission*

A main concern in the world today is how climate is changing and the real causes of this climate change. Climate on earth is mainly managed by the greenhouse effect, which is a natural process that plays a major part in shaping the earth's climate. It produces the relatively warm and hospitable environment near the earth's surface where humans and other life-forms have been able to develop and prosper. It is one of a large number of physical, chemical and biological processes that combine and interact to determine the earth's climate.

The relationship between the enhanced greenhouse effect and global climate change is far from simple. Not only do increases concentrations of greenhouse gases affect the atmosphere, but also the oceans, soil and biosphere. These effects are still not completely understood. Also, complex feedback mechanisms within the climate system can act to amplify greenhouse-induced climate change, or even counteract it.

2.1.1 History of Greenhouse Gas Emissions Awareness

Serious concern at the prospect of irreversible changes to climate as a result of human activities began to surface in the scientific community in the 1950s. This concern was founded on two closely linked considerations: the expectation that the burning of fossil fuels since the Industrial Revolution would eventually lead to significant build-up of carbon dioxide in the atmosphere; and simple physical arguments which suggested that the greater the concentration of carbon dioxide in the atmosphere, the greater the surface warming.

The First World Climate Conference (FWCC) was convened by the World Meteorological Organization (WMO) in February 1979 to examine the climate issue. An extensive international array of organizations and processes now exist, through which nations are attempting to achieve coordinated global action in the climate change issue.

More importantly, systematic linkages have been established between the major UN system organizations dealing with climate change, from the monitoring and research carried out under the World Climate Programme and related monitoring and research programs, through to the scientific, technical and socio-economic assessment work of the IPCC, to the political negotiations of the Framework Convention on Climate Change (FCCC) (Australian Government, 2007).

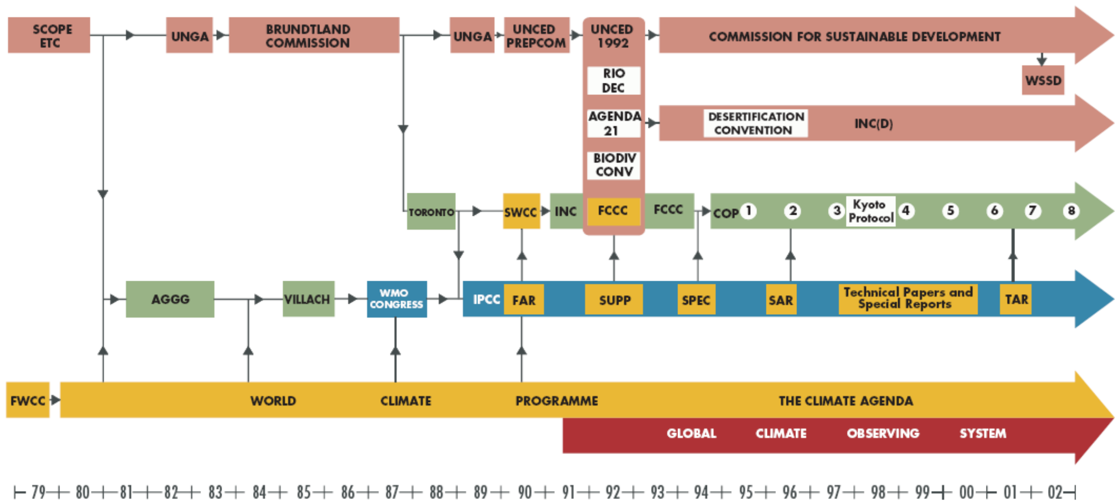

Figure 2-1: Some of the major influences and events in the international development of the climate issue [Source: Bureau of Meteorology – Australian Government]

Figure 2-1 shows the evolution of greenhouse gas concerns from the time of the First World Climate Conference (FWCC) and the establishment of the World Climate Program (WCP) by the World Meteorological Organization (WMO) Eighth Congress in 1979 through to the Eighth Session of the Conference of the Parties to the Framework Convention on Climate Change (COP FCCC) in October-November 2002. Is possible to see the beginning of the Kyoto protocol which started on 1995 was officially opened for signatures on 1997 and started applying with force on 2005. Kyoto treaty goes into effect, signed by major industrial nations except US and Australia.

2.1.2 Actual Greenhouse Gas Emissions Trend

Global greenhouse gas (GHG) emissions have grown since pre-industrial times, with an increase of 70% between 1970 and 2004. Since pre-industrial times, increasing emissions of GHGs due to human activities have led to a marked increase in atmospheric GHG concentrations. Between 1970 and 2004, global emissions of CO2, CH4, N2O, HFCs, PFCs and SF6, weighted by their global warming potential (GWP), have increased by 70% (24% between 1990 and 2004), from 28.7 to 49 Gigatonnes of carbon dioxide equivalents (GtCO2-eq)(Bureau for Development Policy, 2003; IEA, 2006). The emissions of these gases have increased at different rates. CO2 emissions have grown between 1970 and 2004 by about 80% (28% between 1990 and 2004) and represented 77% of total anthropogenic GHG emissions in 2004.

The largest growth in global GHG emissions between 1970 and 2004 has come from the energy supply sector (an increase of 145%). The growth in direct emissions in this period from transport was 120%, industry 65% and land use, land use change, and forestry (LULUCF) 40%.

Between 1970 and 1990 direct emissions from agriculture grew by 27% and from buildings by 26%, and the latter remained at approximately at 1990 levels thereafter. However, the buildings sector has a high level of electricity use and hence the total of direct and indirect emissions in this sector is much higher (75%) than direct emissions.

The effect on global emissions of the decrease in global energy intensity (33%) during 1970 to 2004 has been smaller than the combined effect of global income growth (77 %) and global population growth (69%); both drivers of increasing energy-related CO2 emissions. The long-term trend of a declining carbon intensity of energy supply reversed after 2000. Differences in terms of per capita income, per capita emissions, and energy intensity among countries remain significant.

The emissions of ozone depleting substances (ODS) controlled under the Montreal Protocol, which are also GHGs, have declined significantly since the 1990s. By 2004 the emissions of these gases were about 20% of their 1990 level.

A range of policies, including those on climate change, energy security, and sustainable development, have been effective in reducing GHG emissions in different sectors and many countries. The scale of such measures, however, has not yet been large enough to counteract the global growth in emissions.

With current climate change mitigation policies and related sustainable development practices, global GHG emissions will continue to grow over the next few decades. This is proved by the SRES (non-mitigation) scenarios, which project an increase of baseline global GHG emissions by a range of 9.7 GtCO2-eq to 36.7 GtCO2-eq (25-90%) between 2000 and 2030. In these scenarios, fossil fuels are projected to maintain their dominant position in the global energy mix to 2030 and beyond. Hence CO2 emissions between 2000 and 2030 from energy use are projected to grow 45 to 110% over that period.

2.1.3 Emissions Abatement Measures

International actions to reduce global emissions of greenhouse gases are undertaken through the United Nations Framework Convention on Climate Change (UNFCC). The UNFCC was signed by 155 countries at the so called 'Earth Summit' held in Rio de Janeiro in 1992 and came into force in 1994 after ratification by 50 countries. A national government becomes a party to the convention by ratifying it. The ultimate objective of the Framework Convention was "to achieve stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system".

2.1.3.1 Kyoto Protocol (IEA, 2006)

The implementation of the convention is shaped by the Conference of the Parties (COP) which convenes at regular intervals. The third Conference of the Parties

(COP-3) was held in Kyoto, Japan in December 1997 and was where the parties debated and adopted the Kyoto Protocol. The main features of the Kyoto Protocol were that it called on the developed countries to reduce their greenhouse gas emissions by an average of 5.2% below 1990 levels by a five year commitment period, 2008 to 2012.

In recognition of their different circumstances, countries agreed different reduction targets. For example, the European Union agreed an 8 per cent reduction, while Norway and Australia were actually allowed to increase their emissions by 1 and 8 per cent respectively, relative to their 1990 levels.

The ratification of the Kyoto Protocol has been more delayed than was initially expected. Several parties, led by the European Commission have now ratified the treaty but many such as the USA and Australia remain opposed to ratification.

The Kyoto Protocol now covers more than 160 countries globally and over 55% of global greenhouse gas (GHG) emissions. Kyoto is underwritten by governments and it is governed by global legislation enacted under the UN's aegis.

The countries that are part of the Kyoto protocol are separated into two general categories: developed countries, referred to as Annex I countries (who have accepted GHG emission reduction obligations and must submit an annual greenhouse gas inventory); and developing countries, referred to as Non-Annex I countries (who have no GHG emission reduction obligations but may participate in the Clean Development Mechanism).

Annex I countries have to meet the requirements the treaty establishes. Any Annex I country that fails to meet its Kyoto obligation is penalized. This penalization is the submission of 1.3 emission allowances in a second commitment period for every ton of GHG emissions they exceed their cap in the first commitment period (i.e, 2008-2012).

Kyoto establishes that by 2008-2012, Annex I countries have to reduce their GHG emissions by an average of 5% below their 1990 levels (for many countries, such as the EU member states, this corresponds to some 15% below their expected GHG emissions in 2008). While the average emissions reduction is 5%, national limitations range from 8% reductions for the European Union to a 10% emissions increase for Iceland; but since the EU intends to meet its obligation by distributing different rates among its member states much larger increases (up to 27%) are allowed for some of the less developed EU countries.

2.1.3.2 Greenhouse Gas Abatement under the Kyoto Protocol

Under the Kyoto Protocol, the greenhouse gas reduction commitments apply to six gases or groups of gases namely; carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), hydro fluorocarbons (HFCs), per fluorocarbons (PFCs) and sulphur hexafluoride (SF6). Those substances that contribute to ozone depletion, namely chlorofluorocarbons (CFCs) and Halons are covered by the Montreal Protocol, a separate international agreement. The contributions of the different gases are weighted according to their Global Warming Potentials (GWP). GWP is defined by IPCC as the time-integrated commitment to climate forcing from the instantaneous release of 1kg of a trace gas expressed relative to that of a reference gas (CO2). The time horizon used for the GWP index is typically 100 years. It is important to note that the contribution of CO2 to climate change is the most significant of all the basket of gases covered by the Kyoto protocol. Therefore, to make significant long term reductions in global warming it is clear that significant reductions in global anthropogenic CO2 emissions will be needed, as well as cuts in the other gases.

2.1.3.3 Contributions to Climate Change

The abatement measures proposed under the Kyoto Protocol to reduce emissions were: to have improved energy efficiency both in end-use and in the supply and conversion sectors; to generate a conscience of fuel switching to reduce the carbon intensity of fossil fuel use, such as substituting natural gas for coal; to increase the use of renewable energy; and use nuclear power.

The nuclear power option has been promoted by a number of Parties at the outset of the process, but technical doubts remain, primarily relating to safety which along with attendant political issues, mean that nuclear power is not universally accepted as a mitigation measure.

Many countries are focusing their greenhouse gas reduction targets on the first commitment period for the Kyoto Protocol (2008 to 2012) and will concentrate on the low cost, easily achieved options. These options can include: fuel switching (coal to natural gas), abatement of N2O emissions at adipic acid[1] plants and methane emission reduction from natural gas pipelines and from coal mining. However, the low cost easy to achieve options will soon be used up and other more expensive abatement options will then be required, for later commitment periods.

2.1.3.4 Flexible Mechanisms

The Kyoto Protocol was designed to set the international legal framework and regulatory convention to administer and manage greenhouse gas reduction efforts. Under the terms of the protocol, parties with legally binding obligations may meet their obligations through the application of three flexible mechanisms: Joint Implementation (JI), Clean Development Mechanism (CDM), and International Emissions Trading (IET). These mechanisms were created by the protocol to enable governments to meet part of their greenhouse gas reduction commitments by developing emissions reduction projects in other countries.

JI projects are undertaken in industrialized countries that have quantitative emissions reductions targets, and CDM projects hosted by developing countries that have no quantitative targets. JI and CDM will transfer environmentally-sound technologies to the host countries, which will assist them in achieving their sustainable development objectives. The concept behind all three mechanisms is that a proportion of the required reductions in greenhouse gas emissions should be achieved at lowest

[1] Adipic acid (IUPAC systematic name: hexanedioic acid) is a chemical compound of the class of carboxylic acids. It is a white crystalline powder appearing as an acid in aqueous circumstances, though it is not highly soluble.

possible costs. It is anticipated that application of the mechanisms will commence in 2008.

- ***Joint Implementation (JI):*** The Protocol establishes a mechanism whereby an Annex I country (or an entity within an Annex I country) can receive emissions reductions units (ERUs) generated by emission reduction projects in another Annex I country. ERUs can be transferred as part of a direct sale of ERUs or as part of a return from investment in eligible projects.
- ***Clean Development Mechanism (CDM):*** The Protocol establishes a mechanism whereby non-Annex I parties can create certified emissions reductions (CERs) by developing projects that reduce net emissions of greenhouse gases. Annex I parties (both governments and private entities) can assist in financing these projects and purchase the resulting credits as a means of achieving compliance with their own reduction commitments.
- ***International Emissions Trading (IET):*** The Kyoto Protocol establishes a mechanism whereby Annex I parties may trade their emission allowances with other Annex I parties. The aim is to improve to overall flexibility and economic efficiency of making emissions cuts.

There are a growing number of projects underway based on the application of JI, CDM and IET. CDM projects can take many forms and include those based on achieving improvements in energy efficiency (both end use and supply side), increased use of renewable energy sources, methane reduction (e.g. from gas capture from landfills), fuel switching, enhanced industrial processes, and the application of sequestration techniques and CO2 sinks (afforestation and reforestation).

2.2 *Non-Conventional Renewable Energy in Australia*

Renewable energy encloses various methods to abate GHG emission. The two most important (or with more visual and media impact) programs on the renewable energy matter are Solar Cities and the Mandatory Renewable Energy Target (MRET) (Australian Government, 2006; Australian Greenhouse Office, 2007; Weller, 2001). Solar Cities is a $75.3 million initiative announced by the Prime Minister in the Energy White Paper, *Securing Australia's Energy Future*, in June 2004.

Solar Cities is an innovative program which is designed to demonstrate how solar power, smart meters, energy efficiency and new approaches to electricity pricing can combine to provide a sustainable energy future in urban locations throughout Australia. It is a partnership approach that involves all levels of Government, the private sector and the local community.

Adelaide, Townsville, Blacktown and Alice Springs are the first four solar cities announced in Australia. With $49 million of funding from the Solar Cities initiative, the Blacktown, Adelaide, Townsville and Alice Springs Solar City consortia are working with industry, businesses and their local communities to rethink the way they produce and use energy. The last city that became a solar city was Alice Springs in Central Australia on April 2007.

The second program mention before is the MRET. The Renewable Energy (Electricity) Act 2000 establishes the Mandatory Renewable Energy Target (MRET) which requires Australian electricity retailers and other large buyers of electricity to collectively source an additional 9500GWh of electricity per annum from renewable sources by 2010. The target established would give enough power to meet the residential electricity needs of four million people.

MRET has facilitated the development of additional generation of electricity from a diversity of sources and contributed to a reduction in greenhouse gas emissions. Instigating a significant boost in investment into Australia’s fledgling renewable energy industry, specifically in regional Australia, MRET has established renewable industries encouraging plant upgrade and modernization projects.

The Australian Greenhouse Office's best estimate for the contribution of MRET to greenhouse gas abatement is approximately 0.37 Mt (million tonnes) of carbon dioxide equivalent (CO2-e) for 2001 and 0.70 Mt of CO2-e for 2002. By 2012, abatement is expected to be approximately 6.5 Mt of per annum. On 15 June 2004, the Australian Government reconfirmed its commitment to the MRET scheme at the current level of 9,500GWh by 2010.

2.2.1 Facts of Australian Energy Consumption

Total primary energy consumption in Australia is dominated by fossil fuels, where is possible to find crude oil, black coal, natural gas and brown coal. Although some primary fuels can be used directly by end users, many need to be converted to a form which is more convenient for the end user, like electricity or petroleum. The electricity generation sector is the largest consumer of primary energy in Australia.

Conversion processes consume significant amounts of energy. Around 70 per cent of the primary energy consumed to supply electricity to end users is lost in conversion, transmission and distribution. The losses represent 30 per cent of total primary energy used.

Analyzing the percentage that energy has on the expenditure scheme, energy accounts for a small proportion of expenditure across most sectors (from 1.6 per cent in the commercial sector to 6.8 per cent in the industrial sector) and accounts for around 3 per cent of total expenditure in the economy as a whole.

Energy consumption has grown significantly over the last 30 years, because of growth in output. But primary energy consumption per dollar of output is estimated to have fallen, due largely to structural shifts away from energy intensive sectors of the economy. Compared to other OECD countries, Australia has a relatively high level of energy consumption per unit of output. However, such comparisons can be misleading because of significant differences between countries in climate, energy prices and the size of energy-intensive industries. Australian energy prices are low by international standards.

Consumption of fossil fuels contributes to greenhouse gas emissions. Around 48 per cent of Australia’s greenhouse gas emissions have been attributed to stationary energy users (70 per cent of these are attributable to electricity generation). Around 14 per cent of emissions have been attributed to the transport sector. Australia’s greenhouse gas emissions from energy consumption have grown over the last 30 years as output has grown. However, emissions per unit of output fell by 17 per cent between 1973-74 and 2000-01.

2.2.2 Effects of NCRE in the Australian Electricity Market (NEMMCO, 2007)

To analyze the effects of renewable energy in the Australian electricity market, a study in the NEM will be done first because it is the biggest system in Australia and could show a tendency on how the rest of the market behaves.

If we analyze the list of generators that National Electricity Market (NEM) has got is possible to notice that renewable energy generation in the NEM constitutes less than 2% of the actual installed generation capacity, and its variation in output is having only very minor effects on power system and market operation.

What is important to see is that the amount of wind generation could and should increase very rapidly over the next few years, with some forecasts predicting up to 1000 MW of wind energy capability in NSW, 300 MW Victoria, 850 MW in South Australia and 470 MW in Tasmania. This would take the actual 2% of renewable energy generation to an approximate of 10% on 2010, depending on the real market growth.

Such levels of intermittent generation will present new circumstances to the Australian Electricity Market and in particular in this case to the NEM. To study the situation that the NEM will experience, NEMMCO has initiated exploratory work to understand and review operational issues that could emerge. To date, NEMMCO has identified issues in the following broad areas:

- Accuracy of central forecasting processes
- Frequency control ancillary services
- Voltage control
- Network management
- Connection issues

NEMMCO believes that one of the keys to better understanding and adequately addressing a number of these issues in both the market and the power system will be to ensure that relevant data is accumulated to identify any correlation between intermittent generation operation and NEM outcomes.

Important points to note are put forward for consideration in association with some of the issues identified. In some cases, however, if the issue is material its resolution could require close cooperation between National Electricity Market participants, including NEMMCO, wind generation operators and governments.

The NEM design requires NEMMCO to manage the system through a central dispatch process, which ultimately results on instructions to all scheduled plants, and the determination of spot prices for the market every five minutes. This central dispatch process is supported by a suite of centrally managed but market based forecasting processes. The market design relies on these forecasting processes to signal anticipated supply adequacy or price conditions, and therefore to see if a response is needed from participants.

In the NEM there are two different types of generators, these are the Scheduled Generators and the others are the Non-Scheduled Generator. The second generators just mentioned include all the renewable energy generators that are in the interconnected systems as well as generation with other technologies that are simply not included in the NEMMCO scheduling. So, NEMCO has to determine how much demand and non-scheduled generation there it will be to be able to dispatch the scheduled generators. Basically the system is satisfied by all the non-scheduled generation plus the scheduled generation, where this last one covers all the remaining amount of non-satisfied demand, as shown on Figure 2-2.

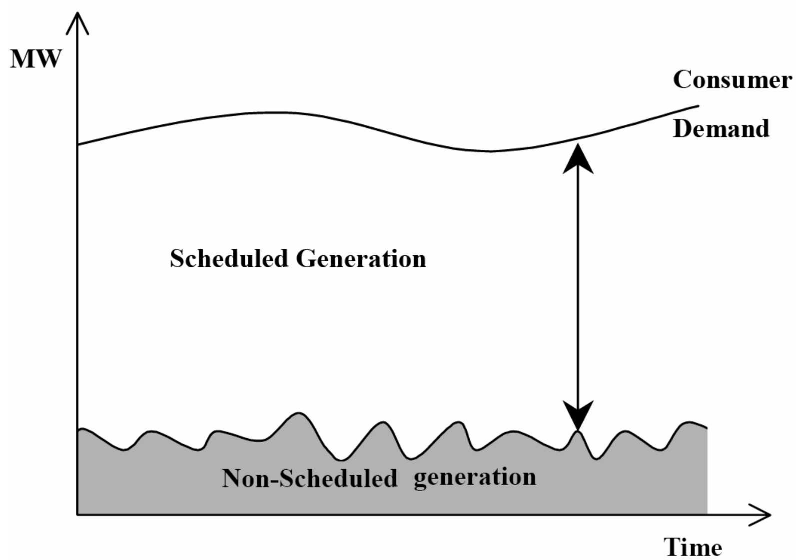

Figure 2-2: Components of consumer demand [Source: NEMMCO]

As is possible to observe in Figure 2-2, variations in non-scheduled generation will appear as opposite variations in scheduled generation. When the contribution of non-scheduled generation has a large variable nature, the scheduled generation will be increasingly difficult to predict.

The main issue is that NEM processes that rely on forecasting will potentially become less accurate as the amount of intermittent generation (i.e. some renewable energy technologies) increases. In the case of generation reserve forecasts, this could translate into higher reserve level requirements to cover uncertainties in the availability of intermittent generation which increases the cost of the entire system. In the case of price forecasts, a decrease in price forecast accuracy may be observed, which produces an uncertainty to big clients in the market.

2.2.2.1 Long Term Processes

The intermittently profile that the new generation would show may fosters to explicitly model the contribution of non-scheduled sources of supply in the forecasting process as their volumes increase. While it is not possible to precisely specify the contribution of wind generation or other intermittent source, NEMMCO thinks that is possible to improve the accuracy of the forecasts by:

1. Applying an appropriate discount factor to the installed capacity of the plant – perhaps varying the factor seasonally and with location.
2. Determining from historical data the non-scheduled generation level for which each individual power station or wind farm has a 90% probability of exceeding (to complement the demand forecast on a 10% probability of excedance (POE)).
3. Determining from historical data the total non-scheduled generation level that has a 90% POE (to complement the demand forecast on a 10% POE and take diversity into account).

2.2.2.2 Real Time Dispatch

On the NEM the real time dispatch process operates every 5 minutes, with scheduled plant being dispatched to meet the anticipated scheduled demand for the instant in time 5 minutes into the future. This process also sets the final spot price applicable for that 5-minute interval. Now, in determining the scheduled generation dispatch, it may prove difficult to make any assumptions in respect of the amount or direction of change that might occur in non-scheduled generation.

When there is not historical operational data available, NEMMCO, initially adopts the assumption that the intermittent generation will not materially change over the five-minute period, and review this assumption as data is collected, remembering that the amount of intermittent generation today is not big enough to affect enormously the system . However, if intermittent generation sources have a clear daily generation pattern, that pattern could be applied to improve the forecast. In addition, modeling the non-scheduled generation separately from the intermittent generation may result in more accurate forecasts that account for daily patterns more accurately.

2.2.2.3 Amount of Renewable Energy in the NEM

In the NEM, as today, the amount of renewable energy represents approximately the 2% (1000 MW approx.). That percentage has not affected the system yet, this means that the price changes and market adversities have not being because of the inclusion of these generators into the system.

Table 2-1: Wind Generation on NEM [Source: NEMMCO]

Name	State	Technology	REG CAP (MW)
Wattle Point Wind	SA	Wind	90.75
Canunda Wind Farm	SA	Wind	46
Cathedral Rocks Wind Farm	SA	Wind	66
Lake Bonney Wind Farm	SA	Wind	80.5
Wonthaggi Wind Farm	Vic	Wind	12.00
Codrington Wind Farm	Vic	Wind	18.20
Yambuk Wind Farm	Vic	Wind	30.00
Woolnorth Wind Farm	Tas	Wind	140.00
Woolnorth Wind Farm	Tas	Wind	114.00
Challicum Hills Wind Farm	Vic	Wind	52.50
Toora Wind Farm	Vic	Wind	21.00
Windy Hill Windfarm	Qld	Wind	12
Starfish Hill Wind Farm	SA	Wind	34.5
Mount Millar Wind Farm	SA	Wind	70
		TOTAL	**787.45**

On the table above is possible to see the amount of wind generation installed today in the NEM. It is important to notice that the registered generation capabilities are aggregated, which means that is the sum of many units in one farm. In the next section it will be specified how the generation matrix will change due to the inclusion of government regulation on renewable energy generation.

As mentioned before, the NEM has not been affected by the small amount of renewable energy generation. Taking the data form MENMCO about demand and prices on its systems, and putting them into a graph, it is possible to observe some price variations but these variation have nothing to do with the inclusion of renewable energies. Note that Tasmania is not included because the interconnection to the NEM (Basslink) was done less than two years ago (2005), so it is difficult to see any important changes of the price.

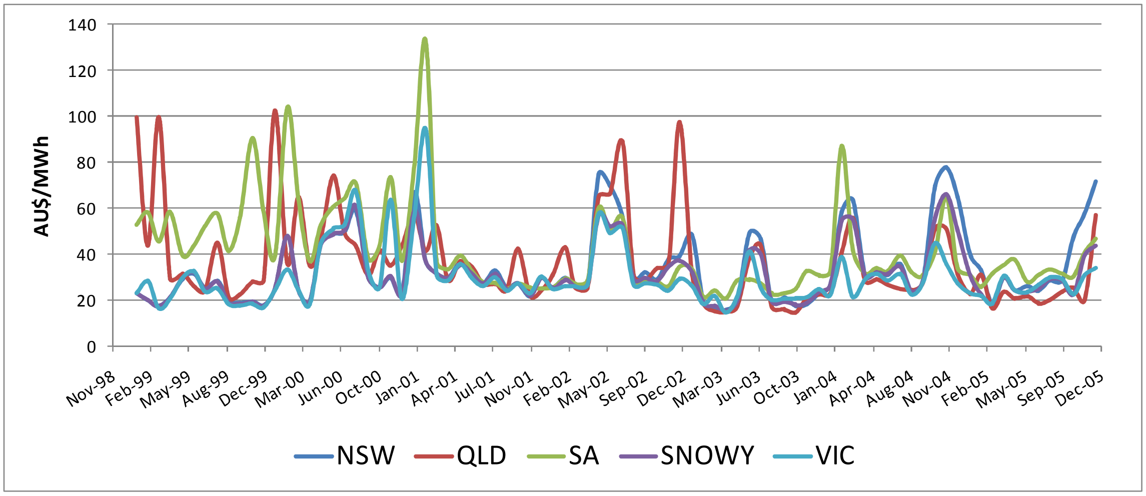

Figure 2-3: Market Prices per System

Figure 2-3 shows the RRP (Reference Regional Price) for each system. This price represents the marginal price of energy production and is defined regionally because each system operates as an independent systems and it sells electricity to the other systems through the interconnectors. This is the main reason why the prices are different.

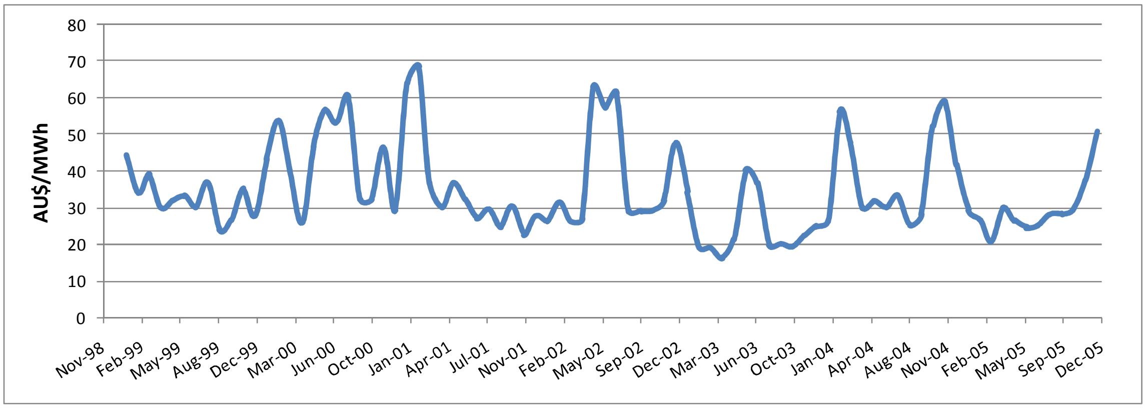

Figure 2-4: Market Average Monthly RRP

The reasons of prices variation can be found on a report on history of price forecasts 1999-2006 done by MMA (McLannan Magasanik Associates), 4 April 2007. Basically changes on prices are because weather conditions, interconnections between systems, gas supply problems among other circumstances.

The market and prices future variation will be shown in the next section, where the whole Australian market is analyzed under the view of a study done by an Australian consulting company to the Australian government.

2.2.2.4 Australian Electricity Market

The Australian government has developed an Act (Renewable Energy (Electricity) Act 2000) where imposes the accomplishment of a certain amount of generation with renewable energy technologies. For this it has created the Mandatory Renewable Energy Target Scheme (MRET) which imposes an obligation on electricity retailers and large consumers to purchase a percentage of their power requirements from renewable sources. For liable parties to meet their proportion of the targets (percentage of generation), they need to know their total amount of liable purchases of electricity (relevant acquisitions). The total liable purchases are multiplied by the Renewable Power Percentage (RPP).

To facilitate this objective, qualifying renewable energy generators are permitted to create tradable Renewable Energy Certificates (RECs) for each MWh of renewable electricity generated. Electricity retailers and large customers submit a legislated number of RECs in proportion to their electricity purchases in each year of the operation of the scheme. The RPP is specified in the Regulations for each year and is used for determining the number of Renewable Energy Certificates (RECs) which must be surrendered by the liable party each compliance year to discharge their liability under the Act. For example the RPP for 2006 is 2.17%.

MRET has been reviewed in the last years and it is important to notice the impacts of changes to the target of renewable generation under the MRET measure. Basically the target requires the generation of 9,500 GWh of extra renewable electricity per year by 2010, enough power to meet the residential electricity needs of four million people. Note that the MRET establishes a lower bound which does not mean that it cannot keep growing after 2010.

The Act specifies that the renewable energy target scheme applies to electricity sales in all grids bigger than a specified threshold of 100 MW. Based on this threshold, grids included are:

- The NEM, covering the interconnected grids of Queensland, New South Wales, Victoria, South Australia and Tasmania.
- The South West Interconnected System of Western Australia (SWIS).
- The North West Interconnected System of Western Australia.
- The Darwin - Katherine Interconnected System (DKIS).
- The Mt Isa Region grid.

Although customers supplied by smaller grids are not liable under the scheme to source electricity from renewable generation options, renewable energy in those systems can still contribute towards meeting the target in other grids.

To be able to see how the market changes, the target will be projected taking as reference the study done by McLennan Magasanik Associates (MMA). The MRET will increase from 9,500 GWh in 2010 with a linear increase to 20,000 GWh in 2020. Each generator, established after 2005, can only be eligible for 15 years worth of RECs.

2.2.2.5 How Renewable Energy Generators can survive in the Australian Market?

Basically, renewable energy generators can survive in the market by earning enough revenues to cover its capital and operation costs. Renewable generators earn revenue from the following sources (McLennan Magasanik Associates Pty Ltd, 2003):

- Sale of electricity (energy) in the wholesale market.
- Avoiding network costs and other wholesale market fees. This can be achieved by government subsidies or generating on locations close to the load.

- Revenue from other services provided. For example, some waste-to-energy generators earn revenue from avoiding landfill charges and from processing recyclable material.

All this way to increase revenues can be diminished by the significant costs these generators have to face. The main cost is the capital cost, which tends to be higher on a per unit output basis than for conventional generation. For biomass projects, fuel cost is also an important cost component. Other costs incurred include transmission connection costs, which can be high in remote regions, ancillary service costs and market fees.

Other factor that compromises a renewable energy project is the amount of risks they have to face. These risks include (Weller, 2001):

- High sponsor risk. The reluctance of customers to enter into long-term contracts for the electricity output increases the risks faced by renewable generators.
- Reliability of supply. Intermittent generation for some renewable technologies means they cannot be relied upon to generate in periods of high prices.
- Fuel supply and aggregation cost. For biomass generators there are uncertainties over the amount of fuel available and its cost.
- Technology risk.
- Large transaction costs. Approval costs and financing costs are the same for small projects as for large projects, tending to increase per unit cost of generation for the small scale renewable projects.

Due to the high costs that renewable energy generators have to face, renewable generation would not enter the market without revenue from other sources. The creation and sale of certificates under MRET enables additional revenue to be earned.

2.2.2.6 Future Wholesale Price Variations

To determine the future price variations is necessary to establish the amount of renewable generation that will enter in the system. For this, MMA has a detailed database of renewable energy projects. It contains 344 existing projects, 33 committed projects (500MW), 120 planned projects (2,960 MW) and 79 potential projects (810 MW)(McLennan Magasanik Associates Pty Ltd, 2003). This means a potential of over 4,270 MW of new capacity.

MMA on its study ran a simulation which considered capital costs of the projects, likely reductions in capital costs over time, operating and fuel costs, connection costs, and other costs for each project. Taking all these factors and simulating the rest of the system, MMA obtained the wholesale electricity prices (AU$/MWh) for 2010, 2020 and 2030, for the different systems around Australia. On Table 2-2 is possible to see that the prices do not show the same behavior on every system. In Tasmania, South Australia, Victoria and Queensland the price goes up, but in the other systems the price goes down. This could have an explanation on the amount of renewable energy injected on each system, that difficult to determine because MMA does not specify in which systems go each project.

Table 2-2: Wholesale Electricity Prices (AU$/MWh)

System	2010	2020	2030
Tasmania	35.2	37.1	36.9
South Australia	49.8	51.8	51.1
Victoria	44.2	52	51.1
New South Wales	41.9	38.2	38.6
Queensland	37.3	40.7	39.4
Western Australia	50.8	47	47
Northern Territory	58.5	54.4	54.2
Australian average	45.4	45.9	45.5

Albeit is not possible to determine whether or not the prices vary cause of the inclusion of renewable generation, it is possible to compare this prices with the data obtained from NEMMCO’s web page. Any change of the prices there will be because of renewable generation inclusion. For this comparison we will take the wholesale prices

(1999-2005) in the NEM system (i.e. SA, VIC, NSW and QLD) excluding Snowy river system and Tasmania system.

Table 2-3: Historical Wholesale Prices [Source: NEMMCO]

System	1999	2000	2001	2002	2003	2004	2005
New South Wales	22.7	35.6	33.3	39.8	26.4	45.1	35.8
Queensland	41.7	50.4	35.0	47.8	22.5	34.5	25.2
South Australia	54.5	56.9	42.2	35.3	26.7	41.6	33.6
Victoria	22.5	38.2	36.0	33.2	23.1	30.0	26.3

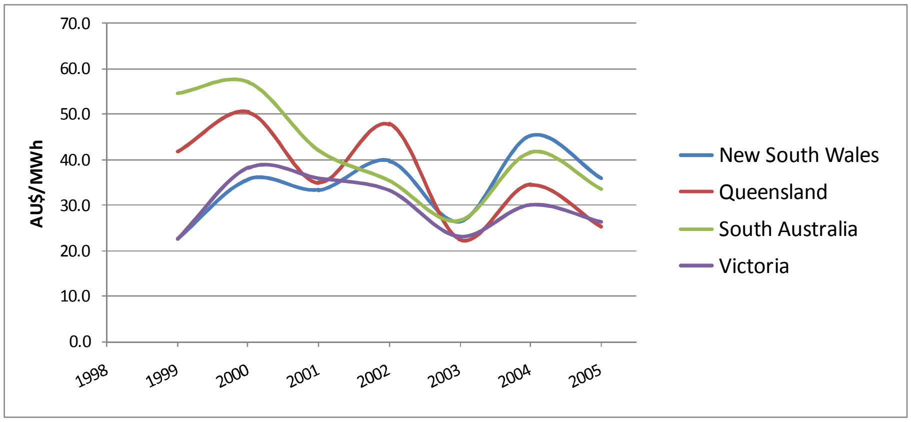

Figure 2-5: Historical Wholesale Prices on NEM

In the curves shown above is possible to observe that the price in a five year period it has been stable with some tendency to go down, showing lower peaks on latter years. In a situation, where the rest of the generation matrix evolves without any big changes of the fuel prices and operation cost, it is to suspect that the price increase should not be bigger than the variation perceived in the last 5 years.

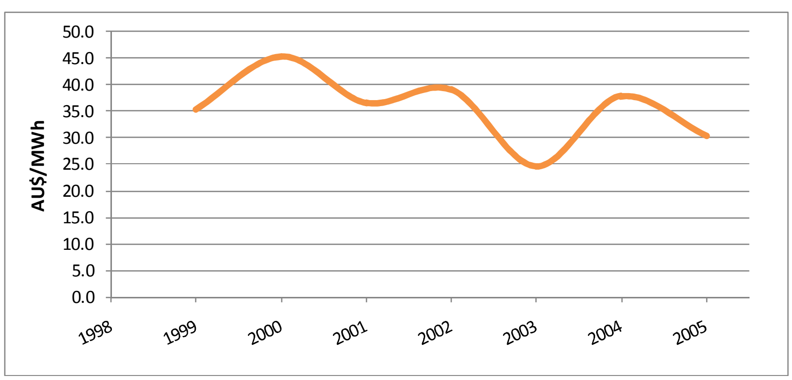

Figure 2-6: Four System Price Average

Observing the price of each system and comparing them with the prices shown on Figure 2-6, is possible to see that prices have gone up and the most affected system is Victoria, where the price difference is the biggest in the NEM systems considered. These variations on the wholesale price could show that the inclusion of a greater amount of renewable generation would affect the price, pulling it up, showing a 30% variation between 2005 and 2010, taking the average of the four systems compared above.

To show an approximated variation of the prices, we will assume that after 2005 the prices stay on the average of the past years as shown on Table 2-4. By doing that is possible to compare this prices with the prices projected by MMA for 2010 including the MRET.

Table 2-4: Average Prices vs. MMA Projection, per System (AU$/MWh)

	New South Wales	Queensland	South Australia	Victoria
Average Prices	34.1	36.7	41.5	29.9
MMA Projected Prices	41.9	37.3	49.8	44.2
Variation	18.6%	1.5%	16.6%	32.3%

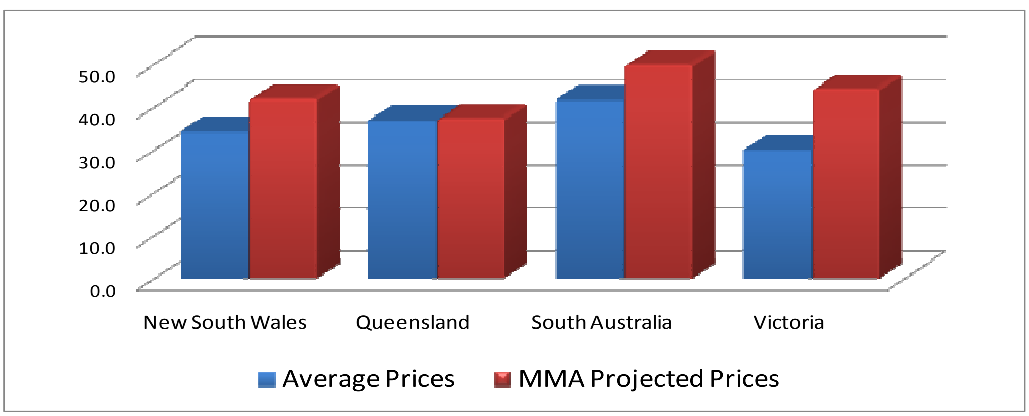

Figure 2-7: Price Difference

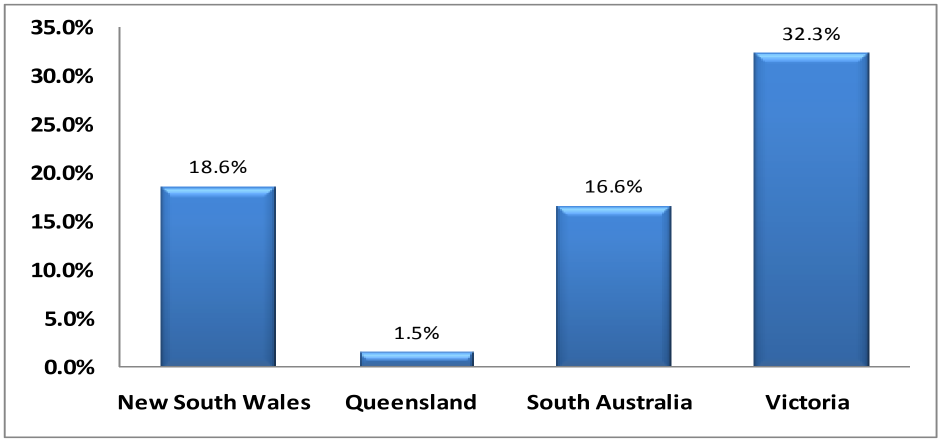

Figure 2-8: Price Variation Percentage (Average Price/MMA projected price)

2.2.2.7 MMA Projected Technology Mix (MMA, 2003)

Considering the Australian context and the renewable energy resources is possible to assume that wind is by far the most dominant renewable energy resource accounting for approximately 40% of the total generation in 2010, referring to the simulations done by MMA (MMA, 2003).

Generation from bagasse makes up the next highest proportion of approximately 9% in 2010. It is important to notice that bagasse generation is heavily constrained by the amount of fuel available.

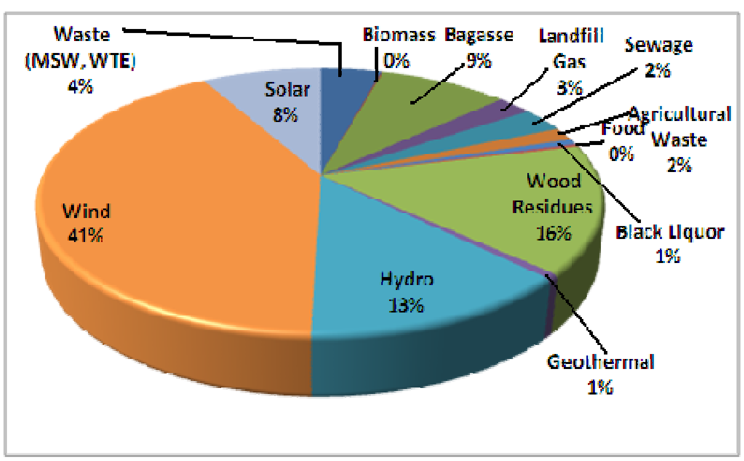

Figure 2-9 : Renewable energy technology mix [Source: MMA]

	2010
Waste (MSW, WTE)	4.2%
Biomass	0.1%
Bagasse	8.9%
Sewage	2.4%
Landfill Gas	3.0%
Agricultural Waste	1.6%
Black Liquor	0.7%
Food	0.3%
Wood Residues	15.6%
Geothermal	0.6%
Hydro	13.0%
Wind	41.4%
Solar	8.2%

2.2.2.8 Greenhouse Gas Abatement (Australian Greenhouse Office, 2007)

A major policy objective of MRET is to reduce greenhouse gases. It seeks to do this by displacing electricity sourced from high emission fossil fuel energy sources with electricity sourced from low emission renewable energy sources.

In 2005, emissions produced by renewable energy sources represent less than 0.5% of the total emissions produced by the energy generation sector and have displaced nearly 2% of fossil fuel energy sources.

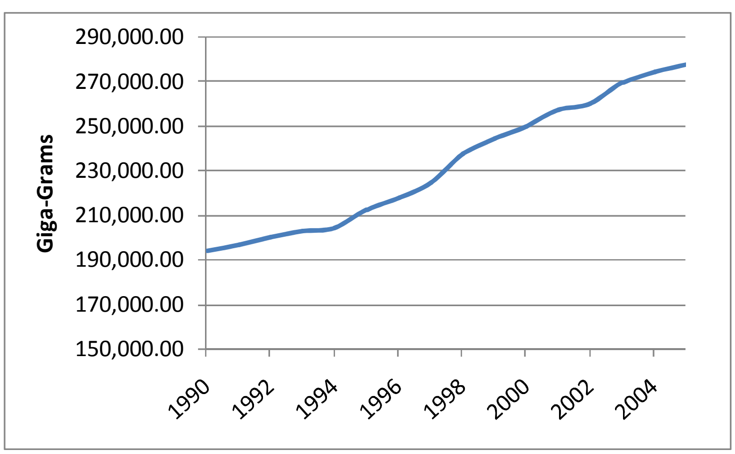

Figure 2-10 : Fossil fuel greenhouse gas emission

Determining the level of abatement that MRET has achieved is a complicated and often misunderstood matter. There are a number of internationally recognized principles that need to be considered when estimating emissions savings, including energy efficiency improvement of fossil generators.

The MRET is, no doubt, achieving lower greenhouse gas emissions. ACIL modeling shows that, as a result of this scheme, emissions abatement of 7.4 million tonnes will be attained in 2010.

Based on the emission of renewable technologies it is possible to calculate that in the case of renewable energies, they produce 1.15 Giga-grams/MW. Doing the same with fossil technologies, they generate 6.95 Giga-grams/MW. This means that renewable energy reducing emissions.

2.3 Research on Wind Energy

Wind energy has been a subject of growing interest worldwide. Essentially, three aspects of wind energy were assessed to identify the state-of-the art:

1. **Wind forecast** (references of interest are Ackermann, Ackermann, Leutz, & Hobohm, 2001; Ahlstrom, Ahlstrom, Jones, Zavadil, & Grant, 2005; M. L. Ahlstrom, Ahlstrom, & Zavadil, 2005; Anandavel, Anandavel, Rajambal, & Chellamuthu, 2005; Ault, Bell, & Galloway, 2007; Baroudi, Baroudi, Dinavahi, & Knight, 2005; Giebel & Kariniotakis, 2007; Karki & Karki, 2004; Potter, Potter, & Negnevitsky, 2006),

2. **System reliability and adequacy** (references of interest are Besheer, Besheer, Emara, & Abdel_aziz, 2006; Besheer, Besheer, Emara, & Aziz, 2006; Roy Billinton, Billinton, & Bagen, 2006; R. Billinton, Billinton, & Guang, 2002, 2004; R. Billinton, Billinton, & Karki, 2002; Chen, Chen, & Hu, 2004; Kana, Kana, Thamodharan, & Wolf, 2001; Karki & Karki, 2004; Karki, Karki, & Billinton, 2001, 2004; Karki, Karki, Po, & Billinton, 2006; Methaprayoon, Methaprayoon,

Lee, Yingvivatanapong, & Liao, 2005; Methaprayoon, Methaprayoon, Yingvivatanapong, Wei-Jen, & Liao, 2007; Pang, Foster, & Troutt, 2000; Pinson, Pinson, & Kariniotakis, 2003; Piwko et al., 2005; Roth, Roth, Kuhn, & Wagner, 2007; Sideratos, Sideratos, & Hatziargyriou, 2007; Smith, Smith, Milligan, DeMeo, & Parsons, 2007; Szabo, Szabo, Biro, Nicula, & Jurca, 2007; Ullah, Ullah, Thiringer, & Karlsson, 2007; Ummels, Ummels, Gibescu, Pelgrum, & Kling, 2006; Ummels et al., 2007; Yang, Yang, Wu, Yang, & Yang Ping, 2004)

3. **Market effects of wind energy inclusion** (references of interest are Abbey et al., 2006; Ackermann et al., 2001; Anandavel et al., 2005; Ault et al., 2007; Bakshl & Bakshl, 2002; Baroudi et al., 2005; Belhomme & Belhomme, 2002; de B. Camargo, de B. Camargo, Carvalho, Garcia, & Sica, 2006; Denny, Bryans, Fitz Gerald, & O'Malley, 2006; Denny & O'Malley, 2006, 2007; Dismukes et al., 2007; Gil & Joos, 2007; Kana et al., 2001; Karki & Karki, 2004; Keane, Denny, & O'Malley, 2007; Kennedy, Kennedy, Fox, & Morrow, 2007; Ko, Ko, Jatskevich, Dumont, & Moshref, 2006; Limbu, Limbu, Saha, & McDonald, 2007; Manwell, Manwell, Rogers, & McGowan, 2001; Methaprayoon et al., 2005; Methaprayoon et al., 2007; Osborn & Osborn, 2006; Pang et al., 2000; Pinson et al., 2003; Piwko et al., 2005; Sideratos et al., 2007; Smith et al., 2007; Szabo et al., 2007; Ummels et al., 2006; Ummels et al., 2007; Weller, 2001; Yang et al., 2004; Ye, Ye, Barbara, & Sander, 2006; Yong et al., 2006).

The reference list includes the main publications that were used as support for this research.

2.4 Chilean Electricity Market

The Chilean electricity market can be essentially divided into three main activities: generation, transmission and distribution of electricity. These activities are done by companies that are totality private capital controlled, whereas the government only has regulatory functions, control functions and proposes investments plans in generation and transmission, although this last function is only a non-compulsory recommendation for the companies that participate in the electricity market.

In the electricity market there are a total of approximately 31 generating companies, 5 transmitting companies and 34 distributing companies, which altogether are capable of supplying electricity nationwide. The total demand on 2004 was 48,879GWh. This demand is located along the country in four electrical systems (two large ones: SING and SIC, and two isolated small ones: Aysen and Magallanes).

The government office that has more participation on regulating the electricity sector in Chile is the National Energy Commission (Comisión Nacional de Energía (CNE), 2007), who is in charge of elaborating and coordinating plans, necessary policies and norms, all this to lookout for the good operation and development of the national power sector.

2.4.1 Electricity Market Characteristics

2.4.1.1 Generation

Generation is composed by a set of electricity companies that own generation plants. The electricity generated by these generating companies is transmitted and distributed by other sector companies until it gets to the final consumers. This part of the electricity market is characterized by a very competitive market, where is possible to observe a clear existence of economies of scale on the variable operation costs, and the prices tend to show the real production marginal costs. Further information for each system can be found latter on this section.

2.4.1.2 Transmission

The transmission system is the set of lines, substations and equipment destined to the electricity transport from the production points (generating plants) to the centers of consumption (big consumers) or distribution. In Chile all lines or substations with a voltage of 23,000 Volts or higher are considered to be transmission. By Law, the smaller voltage systems are considered to be distribution. The transmission is regulated by an open access scheme, this means all generators can use capacity available of transmission paying the respective tolls.

Given the modifications incorporated by law 19,940 (March of 2004) to the General Law of Electricity Services, the transport of electricity by main transmission systems and sub-transmission systems are electricity public services and therefore the transmission company has the obligation to give service (line use), being its responsibility to invest on new lines or line extensions. In the transmission system it is possible to distinguish the main transmission system (lines and substations that form the common market) and the sub-transmission systems (lines that allow obtaining the energy from the main system towards the different local points of consumption).

The operation coordination of the generating power stations and transmission lines is done on each electrical system by the Centros de Despacho Económico de Carga (CDEC) (Load Economic Dispatch Centers – Market Operators). These organisms are constituted by the main generating and transmitting companies of each electrical system.

2.4.1.3 Distribution

The distribution system is constituted by the lines, substations and equipment that allow serving electricity to final consumers, located in certain geographic areas explicitly limited. The distribution companies operate under a regime of public concession of distribution, with the obligation of giving the service and being regulated on its tariffs.

2.4.1.4 Consumers

The consumers are classified according to the magnitude of their demand in:

1. Regulated clients: Consumers whose demand of power is 2,000kW or less.
2. Free or not regulated clients: Consumers whose demand is greater than 2,000kW; and
3. Clients with right to decide on a regime of regulated tariff or free price, by a minimum period of four years of permanence in each regime: Consumers whose demand is greater than 500kW and inferior or equal to 2,000 KW.

2.4.2 CDEC Obligations

The CDECs are obligated by the 1998 Supreme Decree Nº327 of the Ministry of Mining. Their duty is to regulate the coordinated operation of the generating power stations and transmission interconnected lines to the corresponding electrical system. Their main obligations are:

1. Safe operation and minimum cost of the system
2. To valorize the energy and power for the financial transferences between generators. The valuation takes place on the basis of energy and power marginal costs, which varies at every moment and each point of the electrical system.
3. Periodic energy and power injection and withdraw balance that generators do in a period of time.
4. Elaborate reference information of the basic and additional tolls that each power station must pay.

In Chile there are two CDECs, one for the Sistema Interconectado del Norte Grande (SING) (www.cdec-sing.cl) and one for the Sistema Interconectado Central (SIC) (www.cdec-sic.cl).

2.4.3 Interconnected Systems

There are four interconnected electrical systems in Chile: Sistema Interconectado del Norte Grande – SING (Northern Interconnected System), that covers the territory between the cities of Arica and Antofagasta having approximately 30.17% of the total capacity installed in Chile; the Sistema Interconectado Central – SIC (Central Interconnected System), that extends between Taltal and Chiloé, having 69.01% of the total capacity installed in the country; the System of Aysén takes care of the Region XI consumption with a 0.28% of the total capacity; and the System of Magallanes, that supplies Region XII with a 0.54% of the capacity installed in Chile.

2.4.3.1 Sistema Interconectado del Norte Grande (SING)

The SING supplies power and energy to the consumptions of the regions I and II covering 24.5% of the continental national territory. Approximately, 90% of the SING's consumption is made by large clients, which means mining and industrial clients, classified in the law as client that are not subjected to price regulation. The rest of the consumption is bought by the distribution companies that supply energy to final small consumers, these consumers are subjected to price regulation.

2.4.3.1.1 Generation

There are a total of 6 generating companies operating in the SING that along with one Transmission company, they conform the CDEC-SING. The SING has approximately 3,600MW of installed capacity on 2007. The generation matrix is mainly thermoelectric, having approximately 99.6% of its power station being coal-fired plants, diesel plants and combined cycle natural gas-fired plants. There are only two hydro plants that only represent the 0.4% of the total generation capacity. During year 2007 maximum demand reached the 1,510MW, and the gross energy generation was approximately 13,236GWh.

2.4.3.1.2 Transmission

The transmission system is mainly constituted by electrical lines property of the generating companies, electrical lines owned by clients and electrical lines of the transmission companies. Generally electrical lines owned by clients are dedicated lines that for example go to mining areas like Codelco or BHP Billiton.

2.4.3.1.3 Distribution

There are three distribution companies that operate in the SING: EMELARI S.A. that supplies electricity to Arica, ELIQSA S.A. that supplies electricity to Iquique, and ELECDA S.A., that provides electricity to Antofagasta, and to a part of the SIC, corresponding to the zone of Taltal. Note that SIC and SING are not interconnected. Altogether, these three companies take care of a total of approximately 230,000 clients.

2.4.3.2 Sistema Interconectado Central (SIC)

The SIC is the main interconnected system in Chile, providing electricity to more than 90% of the country's population. The SIC extends from Taltal in the north, to the Great Island of Chiloé in the south. Unlike the SING, SIC mainly supplies electricity to regulated clients (60% of the total supply).

2.4.3.2.1 Generation

The SIC has an installed capacity of 8,632MW (2007). There are a total of 20 generating companies operating in the SING that along with some Transmission companies, they conform the CDEC-SIC.

The generation matrix has approximately 56% of hydro power stations and 44% of its power station being coal-fired plants, diesel plants and combined cycle natural gas-fired plants. During the year the 2006 the maximum demand was approximately 4,800MW, whereas the energy gross generation was around the 38,000GWh.

2.4.3.2.2 Transmission

The transmission system is mainly constituted by electrical lines property of the generating companies and electrical lines of the transmission companies.

2.4.3.2.3 Distribution

There are 31 distribution companies operating in the SIC, altogether take care of a total of nearly 3,850,000 clients.

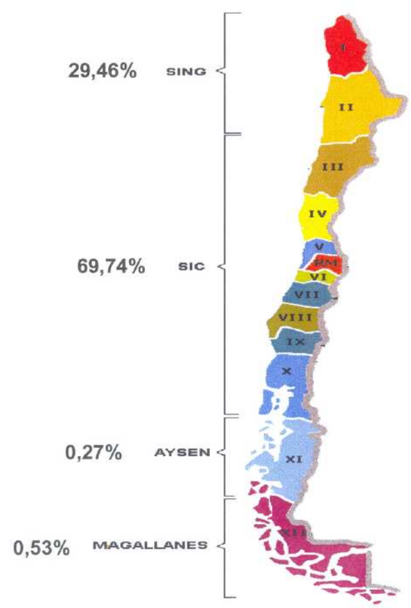

Figure 2-11: Chilean electricity market generation division

2.4.3.3 Aysén System

The System of Aysén takes care of the electricity consumption of the XI Region. Its capacity installed to December of the 2005 reaches the 35MW, where 43.8% is out of thermal technologies power stations, 51.1% hydro and 4.3% of wind power. During year 2005, the average demand reached the approximately 12.8MW and the power consumption was about 112 GWh.

This system is operated only by one company, EDELAYSEN S.A., who takes care of the generation, transmission and distribution of electricity, taking care of a total of around 20,000 clients.

2.4.3.4 Magallanes System

The System of Magallanes is constituted by three electrical subsystems: The systems of Punta Arenas, Puerto Natales and Puerto Porvenir, in the XII Region. The installed capacity of these systems, to December of year 2005, is in total approximately 65MW.During year 2005; the integrated maximum demand of the Magallanes system reached a value close to 45MW, whereas the energy generation was around 220GWh.

This system is operated only by one company, EDELMAG S.A., who takes care of the generation, transmission and distribution of electricity, taking care of a total of around 46,000 clients.

2.4.4 Tariff Scheme

The current legislation establishes that the tariffs must represent the real costs of generation, transmission and distribution of electricity. All this cost assumed to be under an efficient operation of the electricity market. This tariff scheme was designed to give suitable signals to the companies and the consumers, so becomes possible to have an optimal electrical systems development.

The general idea is to let prices be set by the market in those segments where real competition is observed. Hence, when end users power consumption is lower or equal to 2,000KW, the market is considered to be a natural monopoly and therefore, the Law establishes that they are under a regime of price regulation. Alternatively, if users are consuming more than 2,000KW, the Law allows price freedom, assuming negotiating power from both parties, this means generators and consumers.

The first group of clients is the Regulated Clients and the second are the Free Clients, although those clients who have a connected power greater than 500KW can choose regime (free or regulated).

Electrical systems that are greater than 1,500KW in generation installed capacity; the Law establishes two types of prices:

1. Generation-Transport Prices, denominated “Precio de Nudo” (Node Price), and are defined on every substation from where the electricity supply takes place. The node price will have two components: energy price and power price. This price is specified further down.

2. Distribution Prices. These prices will be determined adding the node price, established in the distribution connection points, plus a distribution added value and plus a toll for the use of the main transmission system.

2.4.4.1 Node Price

Node prices are set every six months, on April and October of every year. Its determination is carried out by the National Commission of Energy (CNE); then through a Technical Report results are communicated to the Ministry of Economy, Promotion and Reconstruction, who does the price fixation, through a Decree published in the Official Newspaper (Diario Oficial). The real costs policy and the absence of economies of scale in the generation segment, allow setting as price the marginal cost of supply, constituted by two components:

- ***Basic energy price:*** The basic energy price is the marginal costs average on the study time period, considering that the electrical system is operating at minimum actualized cost of operation and rationalization.

- ***Basic capacity price:*** The basic capacity price is the annual marginal cost of increasing the installed capacity of the electrical system, considering the most economic generating units, established to provide additional power during the hours of annual maximum demand in the electrical system, increased in a percentage equal to the theoretical power reserve margin of the specific electrical system.

NODE	TENSION kV	PENALTY FACTORS CAPACITY [p.u.]	PENALTY FACTORS ENERGY [p.u.]	NODE PRICES CAPACITY [$/kW/month]	NODE PRICES ENERGY [$/kWh]
D. DE ALMAGRO	220	1.1545	1.2903	4857.11	77.524
CARRERA PINTO	220	1.1572	1.2951	4868.47	77.812
CARDONES	220	1.1518	1.2695	**4845.75**	76.274
MAITENCILLO	220	1.0988	1.1838	4622.77	71.125
PAN DE AZUCAR	220	1.0979	1.1746	4618.99	70.572
LOS VILOS	220	1.0269	1.0920	4320.28	65.610
QUILLOTA	220	0.9347	1.0000	3932.39	**60.082**
POLPAICO	220	1.0000	1.0412	**4207.11**	62.557
CERRO NAVIA	220	1.0237	1.0737	4306.82	64.510
ALTO JAHUEL	220	1.0049	1.0558	4227.72	63.435
RANCAGUA	154	1.0454	1.0941	4398.11	65.736
SAN FERNANDO	154	1.0174	1.0648	4280.31	63.975
ITAHUE	154	0.9604	1.0120	4040.51	60.803
PARRAL	154	0.9631	1.0330	4051.87	62.065
ANCOA	220	0.9455	1.0010	3977.82	60.142
CHARRUA	220	0.9357	0.9910	3936.59	59.541
CONCEPCION	220	0.9702	1.0365	4081.74	62.275
SAN VICENTE	154	0.9897	1.0436	4163.78	62.702
TEMUCO	220	0.9971	1.0481	4254.09	62.972
VALDIVIA	220	0.9889	1.0457	4219.10	62.828
BARRO BLANCO	220	0.9885	1.0507	4217.40	63.128
PUERTO MONTT	220	1.0000	1.0611	**4266.46**	63.753
PUGUEÑUN	110	1.2717	1.3494	5425.66	81.075

Figure 2-12: Penalty Factors and Node prices for SIC's substations

For each one of the substations in the electrical system an energy penalty factor is calculated and also another factor for power penalty; that multiplied by the respective basic price, determines the energy price and power price in the respective substation. These factors can be found in the Technical Report published by CNE.

2.4.4.2 Tariffs Types

As mention before, in Chile there are two types of clients: *free clients*, who are connected to a power equal or greater than 2.000kW, and *regulated clients* with connected powers less than this number.

The tariffs of distribution in Chile are regulated by the National Commission of Energy (CNE), and there are different options of tariffs according to the necessity of the client, which are specified in the N°632 Decree of October of 2000. From that decree the following tariffs are obtained:

2.4.4.2.1 Tariff options

The clients will be able to choose one of the following tariff options freely, with the limitations settled down in each case.

- **BT1 Tariff (Low Tension 1):** This tariff is an option of a simple tariff in low tension aimed for clients with simple energy meter. Clients eligible to use this tariff are clients with power consumption inferior to 10 KW and those clients who installed a power limiter to meet this requirement.
- **BT2 Tariff (Low Tension 2):** This tariff is an option of tariff in low tension with contracted power. Eligible clients must have a simple energy meter and contracted power. The clients who decide to choose this tariff will be able to freely contract a maximum power with the respective distributor, this tariff will last for 12 months from the start of the contract. During this period the consumers will not be able to diminish nor to increase their contracted power without the distributor consent. At the end of the annual use of the contracted power the clients will be able to contract a new power. The consumers will be able to use the contracted power at any time without restriction during the usage period of this contracted power. Nevertheless, the contracted power that the client demands will have to be fitted to the capacities of limiters available in the market.
- **BT3 Tariff (Low Tension 3):** This tariff is an option of tariff in low tension with read maximum demand. Eligible clients must have a

simple energy meter and a read maximum demand. It will be understood by ‘monthly read maximum demand’ the highest value of the integrated demands in successive 15 minutes periods.

- **BT4 Tariff (Low Tension 4):** This tariff is an option of an hourly tariff in low tension. This tariff aims for clients with simple energy meter and contracted or read maximum demand and with contracted or read demand on the electrical system peak hours.
- **AT2 Tariff (High Tension 2):** This tariff is an option of tariff in high voltage with contracted power. This tariff aims for clients with simple energy meter and contracted power. The clients who decide to choose this tariff will be able to freely contract a maximum power with the respective distributor, this tariff will last for 12 months from the start of the contract. During this period the consumers will not be able to diminish nor to increase their contracted power without the distributor consent. At the end of the annual use of the contracted power the clients will be able to contract a new power. The consumers will be able to use the contracted power at any time without restriction during the usage period of this contracted power. Nevertheless, the contracted power that the client demands will have to be fitted to the capacities of limiters available in the market.
- **AT3 Tariff (High Tension 3):** This tariff is an option of tariff in high tension with read maximum demand. Eligible clients must have a simple energy meter and a read maximum demand. It will be understood by ‘monthly read maximum demand’ the highest value of the integrated demands in successive 15 minutes periods.
- **AT4 Tariff (High Tension 4):** This tariff is an option of an hourly tariff in high tension. This tariff aims for clients with simple energy

meter and contracted or read maximum demand and with contracted or read demand on the electrical system peak hours.

2.4.5 Energy and Capacity Exchange and Charge

In Chile, the energy is negotiated between generators at marginal cost in the spot market. This energy market has to take place because generators have to fulfill their bilateral contracts and to achieve that sometimes generating companies have to buy the missing generated energy in the spot market. Is important to remember that generators are dispatched by the CDECs on an economic system operation basis, therefore sometimes a generator with a specific contract simply will not be dispatched and has to buy energy for the spot market.

Other energy transaction is done between generators and distributors. This energy is sold at node price in a regulated market. The other exchange is done through agreed free prices between generating companies and large industrial clients on an unregulated market basis.

The capacity however, is paid mainly including an explicit charge for power to the bill that users pay for the electricity use (energy charge). The capacity payment, known traditionally in Chile as payment by firm capacity (Potencia Firme), is a fundamental component for the economic floatability of the generation projects and has taken special relevance for the renewable energy projects because at the moment there are not clear rules about the power percentage for a renewable energy generator that can be remunerated for power assurance.

2.4.6 Non-Conventional Renewable Energy in Chile

2.4.6.1 Renewable Energy Technologies Overview

Chile is characterized for having a big amount of renewable energy on its generation technologies (Hydro). However, this amount of hydro power does not enter into the account of non-conventional renewable energy (NCRE) technologies. In Chile, technologies considered to be non-conventional are:

- Small Hydro plants (less than 20MW)
- Biomass and Biogas
- Geothermal
- Solar Energy
- Wind Power
- Wave Energy

Chile has a total generation capacity of approximately 12,300MW. Considering the total amount of non-conventional renewable energy including all electrical systems on 2006; Chile has 2.4% of its total generation being produced by NCRE, this represents approximately 295MW.

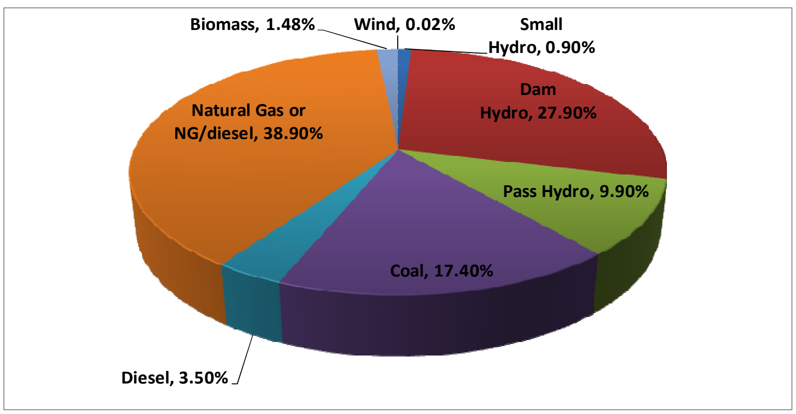

Figure 2-13: Installed Capacity in Chile – 2006 [Source: CNE]

If Chile is observed by electrical systems, there are 4 interconnected systems along the country and each system contributes with some NCRE. In Figure 2-14 is possible to see the amount of NCRE on each system.

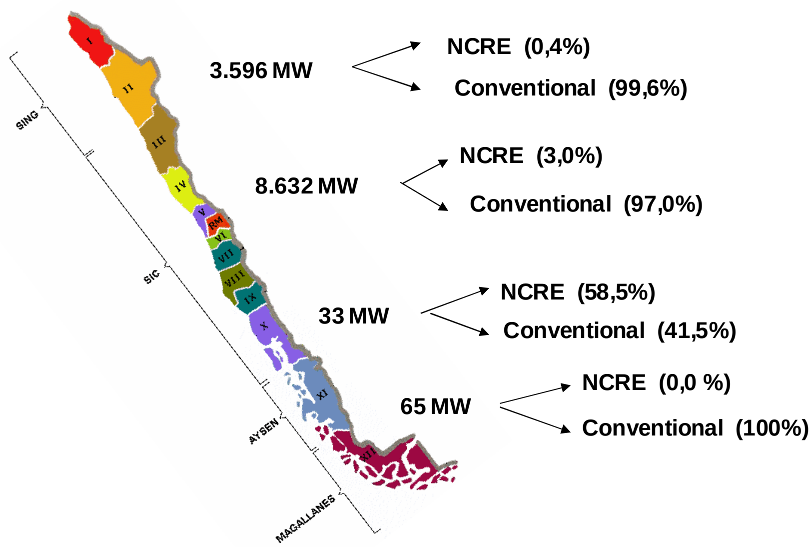

Figure 2-14: NCRE technologies in Chile, 2006 [Source: CNE]

The Chilean government is trying to increase the level of investment on renewable energy technologies. The main purpose of this undertaking is to provide Chile with supply security, to improve the supply efficiency and to create a more environmental friendly development of the electrical sector.

To be able to increase the supply safety is necessary to diversify the competition to be able to create a more competitive market. Also, to generate a safer supply environment is indispensable to have a much hybrid generation technology matrix. Another big player on supply safety is the fuel dependency, which means depending on other countries fuel supply, this triggers a hard to control electricity price.

Other important matter that could be helped by the NCRE is the sustainable development of the energy sector. This aims to have technologies that inflict lesser environmental damage and that allow to develop the electrical system with nil impact of greenhouse gas emissions to the atmosphere.

2.4.6.2 Chilean Renewable Energy Technologies Capability

Chile has many renewable energy resources, which translates into different technologies that can be located along the country. The main technologies and with more potential of development in the country are: Small Hydro, Wind, Solar, Biomass, Wave and Geothermal.

2.4.6.2.1 Small Hydro

These are small power plants, which are capable of generating less than 20MW. Endesa has already got a projected plant to be installed in the Ojos de Agua in the VII region with 9.5MW to be installed by 2008.

2.4.6.2.2 Wind

Wind energy has great potential in the north of Chile. As today, there is only one wind farm in the country located in the Aysen system. This wind farm has 2MW of generating power. Endesa has projected a 9.9MW wind farm to be located in the IV region and being able to generate 26GWh per year.

2.4.6.2.3 Solar

The north of Chile has marvelous potential for solar energy development. Nevertheless there are not many projects related to solar energy in the country.

2.4.6.2.4 Biomass

Biomass is basically solar energy transformed by vegetation on organic matter. Into the category of biomass fuel there are agricultural, forestall and animal residues. According to reports done by PRIEN of University of Chile, there is a potential of more that 300MW is the forestall plantation remains are used.

2.4.6.2.5 Geothermal

According with information obtained from the mining undersecretary's office, Chile has a usable potential of up to 3,350MW on geothermal resources. The main issue that holds back this energy development is the initial installation costs. Is important to know the geothermal energy is the third most important primary renewable energy technology in the world.

2.4.6.3 Renewable Energy Future

The future development of renewable energy in Chile has good potential. At present there are 22 NCRE projects being evaluated in the matter of environmental impact. Taking all the projects together add up 455MW of power that could enter in the electricity market in the future. The projects are basically:

- Small Hydro : 14 Projects (128MW)
- Biomass : 2 Projects (15MW)
- Wind : 6 Projects (312MW)

Also, there is a CNE-CORFO contest to support studies on NCRE investment. This contest has favored 86 projects, which are now being evaluated. These projects represent approximately 640MW of installed generating power with a total investment of AU$997 million. These projects are:

- Small Hydro : 40 Projects
- Biomass : 17 Projects
- Wind : 28 Projects
- Geothermal : 1 Project

The main problem that holds the development back is the investment amount. The different projects require a low variability on future revenues (medium and long term) because each project is very capital intensive. Other problem is the competitive disadvantage when it comes to enter a market where conventional technologies have more possibilities to create bilateral contracts with customers.

2.4.6.4 Technology Reference Price in Chile

To be able to install different technologies in the electricity market they have to be cheaper than the price established in the market. This means that the sale price of the generators has to be higher than the monomial price they have got for the technology. In Chile energy is getting more expensive due to fuel dependency and world fuel price rice; this makes it possible for technologies with higher costs to be able to enter the market and sell its power and energy.

In Chile, the law (Ley Corta II, May 2005) tries to insure required investments in the electricity market and also looks for costs to be as close to the real generation costs as possible. To accomplish this Chile has a contract auction mechanism where distribution companies satisfy their electricity needs with the generators offers, obviously trying to accomplish the lowest possible cost. For this generators are obligated by the nature of the auction to bid with their real costs.

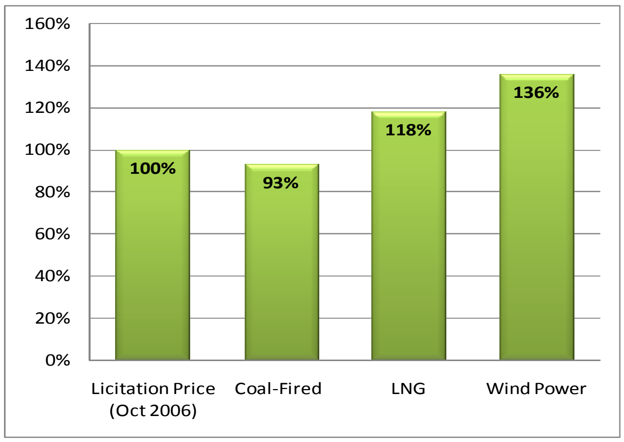

Figure 2-15: Technology Necessary Price to Enter [Source: Colbún S.A.]

Because of the increase of the electricity price, the inclusion of other technologies becomes real. Usually projects with higher risk, located in less favorable areas and with smaller generation capacity will enter under this conditions. It is known that renewable energy technologies have higher monomial prices and, when the price goes up, is very likely for renewable energy technologies to enter.

Taking as reference the auction price obtained on October 2006, Colbún S.A. calculated the percentage of that price compared with the monomial price of other three technologies. Figure 2-15 shows that coal is highly competitive and the other two technologies are not far behind.

2.4.6.5 Renewable Energy Market Incentive

The Chilean government has developed modifications to the electricity law to foster the renewable energy growth in the electricity market. This law project intends to create the conditions to materialize non-conventional renewable energy projects, and to generate confidence in the electricity market related to the development of these technologies in the long term.

The law modifications instate that the 5% of the injected energy by generating companies has to be accomplished by new NCRE technologies, this energy could be used by retailers or free clients. Therefore, the electricity companies should annually certify that the 5% of the total commercialized energy has been injected by NCRE sources.

To make the 5% accomplishment easier and more flexible the NCRE requirements could be generated on any interconnected system and also companies could use NCRE generated the year before the year of the requirement only when that energy has not been declared previously.

The requirements imposed by this law project start from the energy generated from year 2010 and lasts for 20 years (2010-2019). Only the NCRE projects interconnected after May 2007 are eligible to generate under the 5% imposed by the law project. In case a company does not meet the requirements they will have pay a fine equivalent to the non supplied renewable energy.

2.4.6.5.1 Effects of the Law Project

This law aims to increase the amount of NCRE generation in the Chilean electricity market. The main effects projected by the Chilean government are an increase in the NCRE generating capacity (Figure 2-16).

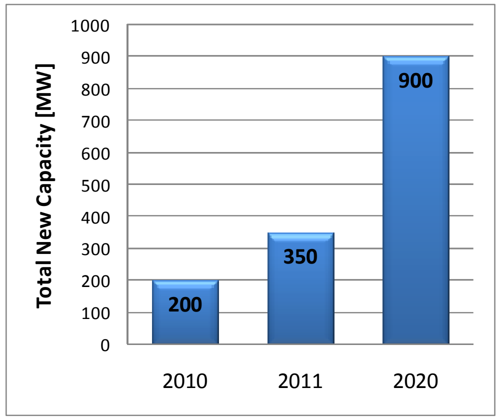

Figure 2-16: Projected NCRE New Capacity [Source: CNE]

Apart from the obligations this law project will impose, is important to notice that NCRE projects will become more efficient, because conventional energy generating companies have to internalize the cost of the new technology into the offers made to the final customers. Also, the Chilean government reckons the price should not vary much because there are many NCRE projects that are highly competitive.

3 METHODOLOGY AND INITIAL CALCULATIONS

3.1 Wind Resource

To be able to estimate the amount of energy generated by each wind turbine is crucial to gather wind data from sites located within the SING. The data used was from a site located close to Calama Airport in the II region and contains data for a period of one year (Jan 2004 – Dec 2004), from now on referred as WP site. All wind data is included in the appendices section. The characteristics of the site are as follows:

Table 3-1: WP Site Characteristics

Annual Average Air Density	0.95 (kg/m^3)
Elevation	2,400 h.a.s.l.
Annual Average	23°C
Annual Average Wind Speed	7.5 m/s @ 70 metres

3.1.1 Data validation

To validate the wind data from the site (Figure 3-1), wind data from Calama Airport was requested to the Chilean Meteorological Centre (www.meteochile.cl), where the data supplied covers a 10 year period (1994-2004) on an hourly basis (Figure 3-2).

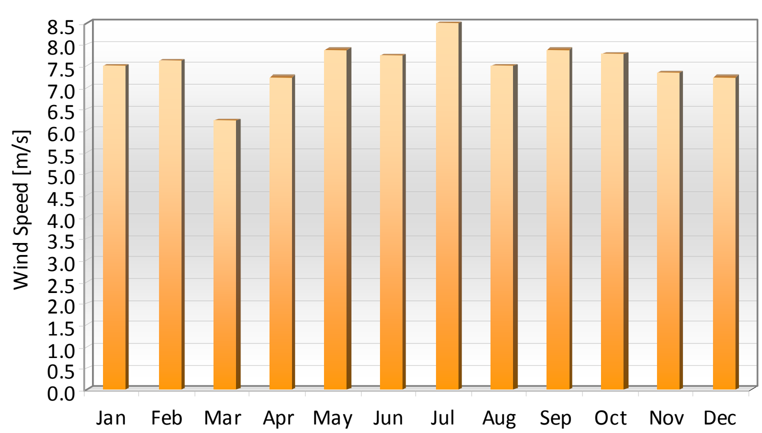

Figure 3-1: WP Site 2004 Wind Data

With this amount of data is possible to analyze the behavior of the wind for each year and with this uphold the veracity of the information for the site under investigation.

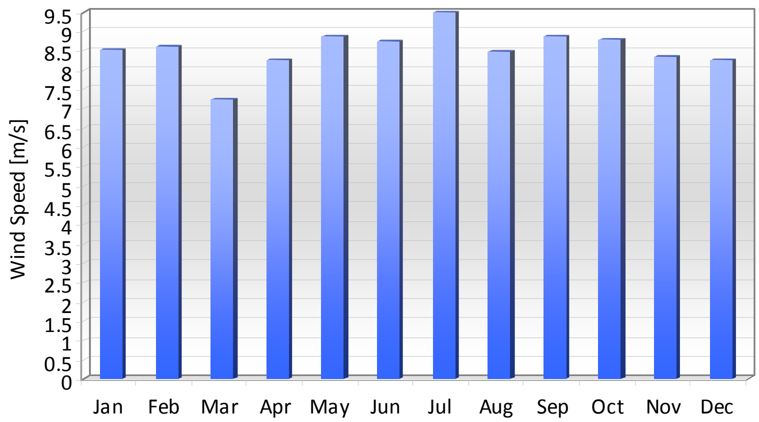

Figure 3-2: Calama Airport 1994-2004 Average Wind Data

Basically, the airport data is compared with the data from the site. The easiest and more effective way to compare these two data sets is to obtain the wind behavior along the day. Then, if this curve has a similar behavior is necessary to build a histogram of the data for each location. Both of these curves will show the similarity of the overall behavior throughout the year, for these places and therefore becomes possible to assume that site will perform like the Calama Airport.

Calama Airport has been registering wind data for a long time and this data is used to analyze the similarity in behavior of both locations. For Calama Airport, two indicators were obtained, the hourly average for every month and the standard deviation for the averaged data. In this case the standard deviation is σ=0.53[m/s], which represents that the interannual wind variability is very low and makes possible to represent Calama Airport's wind behavior with only one year data, which will be the hourly average per month already determined (Figure 3-2).

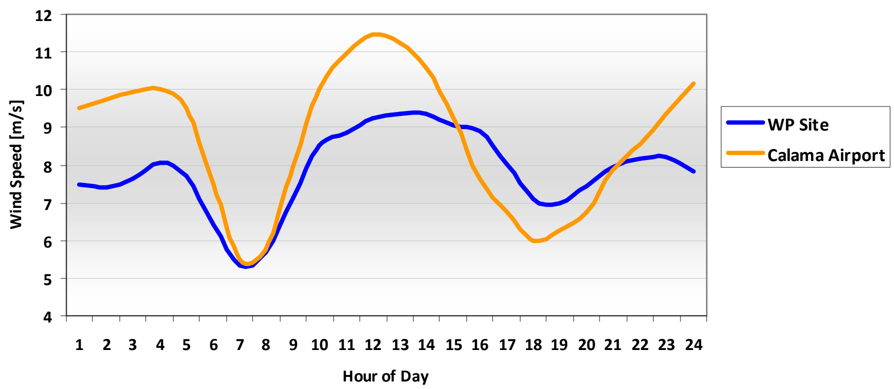

Figure 3-3: Wind behavior throughout the day

As is possible to see on Figure 3-3, the wind has the same behavioral pattern for both places. During the day there are two minimums, one located between 7am and 8am and the second located between 6pm and 7pm. The peak wind can be found at noon. From this figure is likely to suppose that both sites can be compared on a frequency graph, which is the histogram for each location.

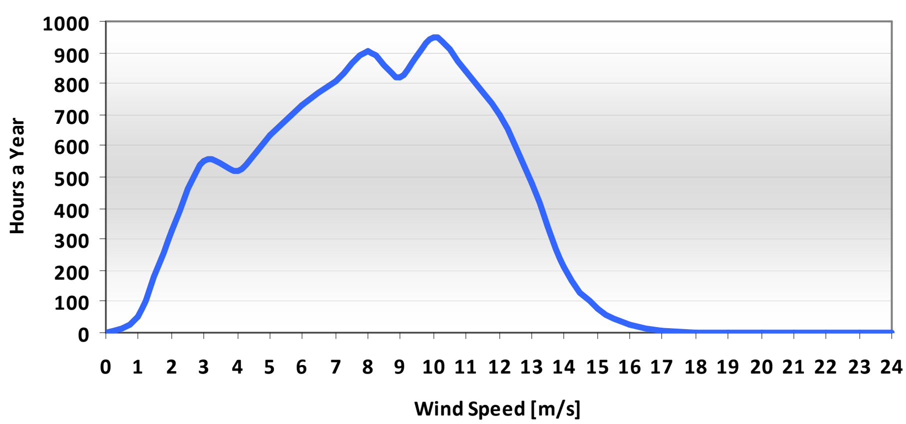

Figure 3-4: WP Site Histogram

On Figure 3-4 is possible to observe that between 8 m/s and 10 m/s the most frequent wind speeds can be found. The following figure shows the shape of the histogram on Calama Airport. This figure shows an extremely similar histogram, where the most frequent speeds are located in the same interval.

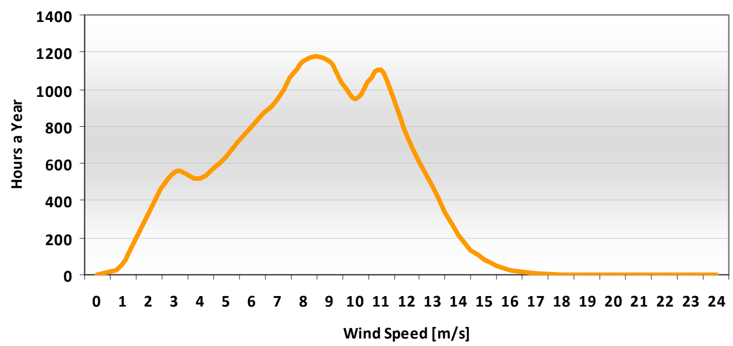

Figure 3-5: Calama Airport Histogram

With these figures is enough to say that the gotten data can be assumed to behave with a similar pattern with the Calama Airport data. With this, the data from WP site can be use to estimate the energy that a supposed wind farm located on this site can generate for the years this wind farm will be working. Is important to remember that the interannual wind speed variability in Calama Airport is very low, which means that the interannual variability on WP site will be as low. Figure 3-6 compares both histograms, is possible to notice the similarity of both curves.

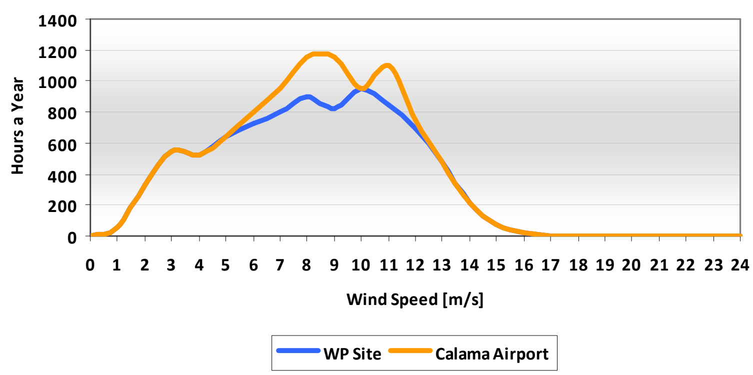

Figure 3-6: Histogram Comparison

3.1.2 Wind Speed Probability

Other than knowing that at the WP site the interannual wind will behave without much variation, is important to know the probability of occurrence of a specific wind speed. To achieve this is necessary to approximate the histogram curve to a Weibull distribution curve. The methodology to create the Weibull distribution is included in the appendices. Figure 3-7 shows the resulting Weibull distribution for WP site. To have clearer view of the probability of a certain wind speed happening Figure 3-8 shows the cumulative distribution, this figure intends to show the probability of a specific wind speed being smaller than the wind speed shown by the graph

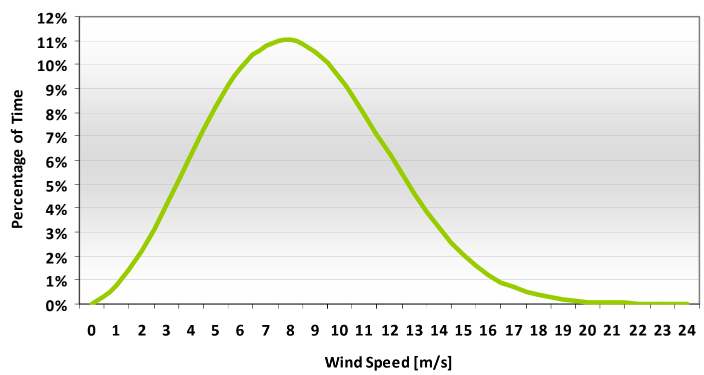

Figure 3-7: Weibull distribution for WP site

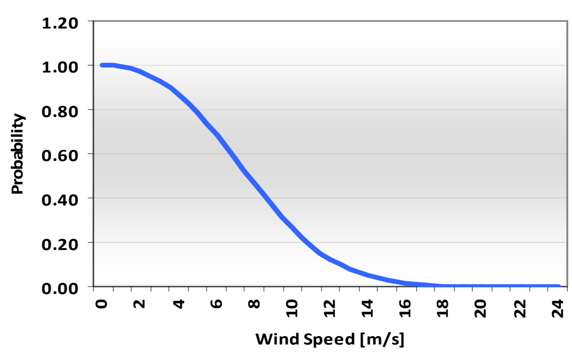

Figure 3-8: Wind Speed Probability

3.2 Simulation

The simulation model used is a multinodal multi-dam model designed by KAS Ingeniería, used in the SIC and capable of simulating systems with a hydro-thermal generation mix. In this model is possible to include line capacities and limitations, merit list dispatch behavior, demand forecast, inclusion of future generation and transmission projects, hydrology variability, etc. The model has also been used in the SING, where is a much more simplified model, where there is not necessary to consider hydrological variability due to a mainly thermal system.

3.2.1 OSE2000 Simulation Model

Due to the random pattern of the hydrological variable that exists on most electricity markets, is indispensable to have a model capable of modeling the hydrothermal behavior of these electricity markets. OSE2000 is a robust toll, capable of solving the hydrothermal problem of an electricity market. Specifically, OSE2000 is capable of:

- Determining the optimal operation of dams on a system.
- Determining the economical dispatch of each unit in the system for a specific demand (separated on demand blocks) considering transmission restrictions and losses on transmission lines.
- Calculating the marginal costs for every system node.

The model is capable of simulating the system within a defined time period, for which is necessary to estimate the future system demand and also the fuel prices for each unit in the system. For the case of a simulation in the SING; it is not necessary to consider the hydrological variable because the system is, almost completely thermal.

3.2.1.1 Generating Units on OSE2000

Generating units on OSE2000 can be separated on:

- Thermal
- Dam Hydro
- Run-of-River Hydro
- Virtual
- Fault

For each one of these types of generators there are three global data that the model considers:

- **Parameters Structure:** Basic data which does not vary throughout the simulation time horizon.
- **Maintenance Structure:** Data that varies throughout the simulation time horizon.
- **Variant Data Structure:** Data that varies within a year.

3.2.1.2 Unit Representation

3.2.1.2.1 Thermal Units

Thermal units are represented by its power capacity and its variable cost, which could vary monthly throughout the simulation horizon. The variable cost for each thermal unit is determined as follows:

$$C_{Var} = \mu \times C_{VarFuel} + C_{VarNoFuel} \tag{3.1}$$

$$\begin{aligned}
&\textit{where,} \\
&C_{Var} && = \textit{Unit Variable Cost} \\
&\mu && = \textit{Thermal Efficiency} \\
&C_{VarFuel} && = \textit{Fuel Variable Cost} \\
&C_{VarNoFuel} && = \textit{No-Fuel Variable Cost}
\end{aligned}$$

For this type of unit there are also considered the forced unavailability ratio and a maintenance program, which is detailed for each unit.

3.2.1.2.2 Dam Hydro

Dam hydro units are represented by the volume flow rate influencing the behavior of the unit's dam. The hydraulic balance equation is the following:

$$Q_{gen} + Q_{spl} + Q_{fil} + Q_{eva} = Q_{afl} + Q_{bal} \tag{3.2}$$

where,

Q_{gen} $= Volume\ Flow\ Rate\ for\ Generation$

Q_{spl} $= Spilled\ Volume\ Flow\ Rate$

Q_{fil} $= Filtered\ Volume\ Flow\ Rate$

Q_{eva} $= Evaporated\ Volume\ Flow\ Rate$

Q_{afl} $= Affluent\ Volume\ Flow\ Rate$

Q_{bal} $= Balancing\ Volume\ Flow\ Rate$

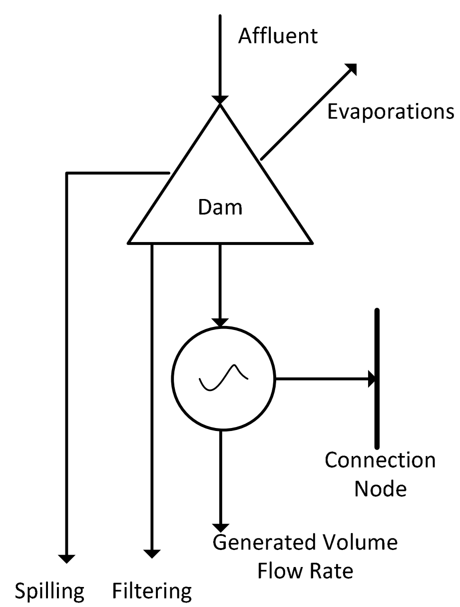

Figure 3-9: Dam Hydro Connectivity

3.2.1.2.3 Run-of-River Hydro

Run-of-river hydro units are represented in the model as an equivalent thermal unit. Where, the generation volume flow rate is the smaller value between the affluent and the maximum generation volume flow.

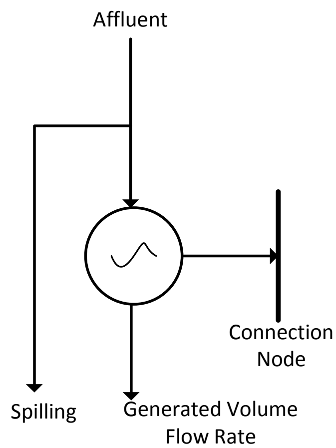

Figure 3-10: Run-of-River Hydro Connectivity

3.2.1.2.4 Fault Unit

Fault hydro units represent the significance of non-supplied demand on a specific node. This unit is automatically assigned to all nodes enabled to have virtual units and that have an assigned demand.

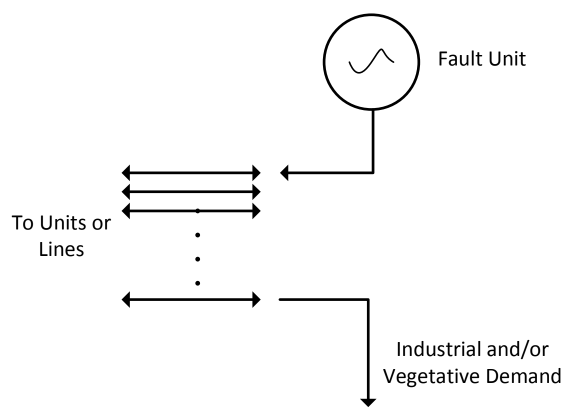

Figure 3-11: Fault Unit Representation

3.2.1.3 Transmission System Representation

OSE2000 incorporates transmission restrictions and line losses in the optimization decisions. Transmission losses are modeled linearly per section, which varies depending on the current flow. This type of modeling is a good approximation, because the error compared to a quadratic function is not considerable.

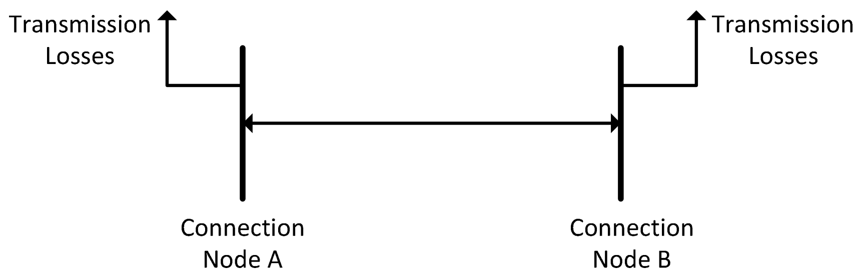

Figure 3-12: Transmission Loss Modeling

Figure 3-12 shows how OSE2000 represents the transmission losses in the connection nodes. Losses can be associated to the emitting and/or the receiving node.

3.2.1.4 Demand Representation

In the model, demand is represented by two different types of demand. One is the vegetative demand and the other is the industrial demand. Industrial demand is represented by connection node and associated to an annual growth rate per node. This type of demand is distributed using load duration curve factors; these factors are unique for industrial demand. Vegetative demand is represented through an annual demand and an annual growth rate; this demand is distributed among the different nodes with node distribution factors and is distributed over the load duration curve using other distribution factors.

The load duration curve has to be represented using demand blocks. The number of demand block will depend on the demand characteristics of a system. With the amount and duration of each demand block is possible to calculate the load duration curve distribution factors.

3.2.1.5 Mathematical Model

OSE2000 mathematical model basically is a linear optimization which minimizes the system operation cost considering the current value of generating with different technologies in the system and the future value of dammed water, which would be an opportunity cost of not generating with hydro units at some stage.

The global optimization problem is:

$$P\,)Min\left[\sum_{t=1}^{N_T}\sum_{s=1}^{N_S}\left[P_{t,s}\cdot\left(C_{t,s}\cdot X_{t,s}+\left(1+d\right)^t\cdot f_T\left(X_{T+1,s}\right)\right)\right]\right] \tag{3.3}$$

$$\begin{array}{llll}
\textit{subject to} & & & \\
A_{t,s}\cdot X_{t,s}+E_{t,s}\cdot X_{t+1,s} & = & B_{t,s} & \forall \quad 1\le t\le N_{T-1}\wedge 1\le s\le N_S \\
A_{T,s}\cdot X_{T,s} & = & B_{T,s} & \forall \quad 1\le s\le N_S \\
\breve{X}_{t,s}\le X_{t,s}\le \widehat{X}_{t,s} & & & \\
\breve{X}_{T,s}\le X_{T,s}\le \widehat{X}_{T,s} & & &
\end{array}$$

where,

d = *Discount Rate*

t = *Stages (time)*

s = *Simulation Sequences*

N_S = *Number of Hydrological simulation sequences*

N_T = *Number of decision stages(time)*

For each t and s,

$A_{t,s}$ = *Electrical Connectivity Matrix*

$E_{t,s}$ = *Hydrological Connectivity Matrix*

$P_{t,s}$ = *Probability of 's' happening on 't'*

$C_{t,s}$ = *Operation and Penalty Costs Vector*

$B_{t,s}$ = *Maximum Connectivity Vector*

$X_{t,s}$ = *State Vector (Electricity Generation or Water Use)*

$f_T\left(X_{T+1,s}\right)$ = *Future Cost Function on the last simulation time stage*

The minimization problem shown by equation (3.3) is extremely large, therefore is necessary to use advanced solving techniques to solve the problem.

OSE2000 uses Blenders' decomposition to obtain solutions to this problem considering $f_T\left(X_{T+1,s}\right)=0$.

Using Benders decomposition allows obtaining a solution for the problem using an iterative algorithm, where time stages are decoupled, representing the future operation with a relaxed future cost function for each decision stage. The relaxed optimization problem showing only one decision stage 't' and one simulation sequence 's' can be written as follows:

$$P\,)Min\left[P_{t,s}\cdot\left(C_{t,s}\cdot X_{t,s}+(1+d)^{t}\cdot f_t\left(X_{t+1,s}\right)\right)\right] \tag{3.4}$$

$$\begin{aligned}
&\textit{subject to}\\
&A_{t,s}\cdot X_{t,s}+E_{t,s}\cdot X_{t+1,s} &=&\quad B_{t,s}\\
&A_{T,s}\cdot X_{T,s} &=&\quad B_{T,s}
\end{aligned}$$

Benders' algorithm builds the future cost function $f_t\left(X_{t+1,s}\right)$ iteratively until achieving an operation cost equal to the operation cost estimated by the relaxed future cost function, this means:

$$(1+d)\cdot\sum_{s=1}^{N_S}\left[P_{t,s}\cdot f\left(X_{t+1,s}\right)\right]+Z_t^{*}-k\cdot\sigma\le Z^{*}\le(1+d)\cdot\sum_{s=1}^{N_S}\left[P_{t,s}\cdot f\left(X_{t+1,s}\right)\right]+Z_t^{*}+k\cdot\sigma \tag{3.5}$$

$$\begin{aligned}
&\textit{where,}\\
&Z^{*} &&=\sum_{t=1}^{N_T}Z_t^{*}\\
&Z_t^{*} &&=\sum_{s=1}^{N_S}\left[P_{t,s}\cdot\frac{C_{t,s}\cdot X_{t,s}}{(1+d)^{t-1}}\right]\\
&Z^{*} &&=\textit{Expected Optimal Operation Cost Present Value}\\
&Z_t^{*} &&=\textit{Expected Optimal Operation Cost Present Value on Stage 't'}\\
&\sigma &&=Z^{*}\ \textit{Standard Deviation}\\
&k &&=\textit{Wanted Precision}
\end{aligned}$$

3.2.2 OSE2000 in the SING

When modeling the SING using OSE2000 is necessary to enter every characteristic of the system into the input files in the model. Is important to know that in the SING the model gets simplified; this because the electrical system is only thermal and therefore does not have to face the hydrological variability. Due to the hydrological variability inexistence the mathematical model becomes a multinodal thermal dispatch and therefore the model shown by equation (3.4) gets simplified. The mathematical model for the SING would be:

$$P\,)Min\left[C_{t,s}\cdot\left(g_{t,s}^{th}+f_{t,s}\right)\right] \tag{3.6}$$

$$\begin{array}{lcll}
\textit{subject to} & & & \\
A_{t,s}^{B}\cdot g_{t,s}^{th}+F_{t,s}\cdot f_{t,s}+P_{t,s}\left(f_{t,s}\right) & = & D_{t} & (1)\\
A_{t,s}^{F}\cdot\theta_{t,s} & = & 0 & (2)\\
C_{t,s} & = & \left[C_{t,s}^{th},C_{t,s}^{flow}\right] & (3)\\
\breve{g}_{t,s}^{th}\le g_{t,s}^{th}\le\widehat{g}_{t,s}^{th} & & & (4)\\
\breve{f}_{t,s}\le f_{t,s}\le\widehat{f}_{t,s} & & & (5)\\
\breve{\theta}_{t,s}\le\theta_{t,s}\le\widehat{\theta}_{t,s} & & & (6)
\end{array}$$

$$\begin{array}{ll}
\textit{where,} & \\
(1) & =\textit{Kirchoff Current Law Balance}\\
(2) & =\textit{Kirchoff Voltage Law Balance}\\
(3) & =\textit{Cost Vector (Thermal Cost, Line Use Cost)}\\
(4) & =\textit{Thermal Generation Restriction}\\
(5) & =\textit{Line Flow Restriction}\\
(6) & =\textit{Connection Node Angle Restriction}\\
D_{t} & =\textit{Connection Node Demand Vector}\\
P_{t,s}\left(f_{t,s}\right) & =\textit{Transmission System Losses Function}
\end{array}$$

3.2.2.1 Wind Energy Inclusion

To be able to include wind energy, the model was adapted by adding the wind farm as if it was a run-of-river generating unit, this to be able to introduce the wind variability. Using the wind generation potential is possible to include it into the model by introducing this data in the 'run-of-river hydrology', which is the affluent file, making sure that the input file is receiving energy data instead of volume flow rate. This data is included weekly, which allows showing some variability of the wind.

Due to model limitations, the software will not be able to perceive daily or even hourly wind variability and therefore will not be able to know exactly how the system will behave. Albeit, due to wind characteristics, analyzing wind energy using OSE2000 is a good approximation and the real behavior should not be excessively different.

3.2.3 Simulation Scenarios

The simulation scenarios considered in the model were twenty different cases, which tried to represent different situations in which the electrical system could behave differently under the inclusion of a wind farm. The scenarios considered three different connection nodes, three different wind farm sizes and two cases of demand growth. Also were included two base cases without wind energy inclusion, one for each demand scenario. The simulation cases are detailed below.

$$Connection\ Nodes = \begin{cases} O'Higgins\ 220 \\ Calama\ 110 \\ Crucero\ 220 \end{cases} \qquad Wind\ Farm\ Sizes = \begin{cases} 57.75MW \\ 90.75MW \\ 173.25MW \end{cases}$$

$$Demand\ Scenario = \begin{cases} Normal\ Growth\ Demand \\ High\ Growth\ Demand \end{cases}$$

3.2.3.1 Demand Scenarios

For the demand, is necessary to define six demand blocks for the load duration curve definition. As shown previously, the demand cases represent two different demand growths, one is a normal demand growth, which is the growth assumed by the National Energy Commission (CNE) and the other tries to show a high growth demand, which could represent a new mining project (large demand) that could be developed in the SING without advising the electricity market operator (CDEC-SING); this means that the system will not be ready to adapt it self to a cheaper technology when the new mining facility starts demanding electricity.

3.2.3.2 Base Cases

As mentioned before, there are two base cases, one for normal demand and the other for high demand. The base cases of the simulation were essentially taken from the actual behavior of the SING with data obtained from the CDEC-SING and from the CNE. Usually CNE is very slanted to the wellbeing of the prices behavior in the SIC, but in the SING, because there is not a very diversified energy matrix and also because the demand is mostly large industrial clients, there is not much difference between the reality and what is published by CNE in the Technical Reports every six months. Hence, there are essentially three main aspects that have to be considered to outline the base case, these aspects are: fuel prices, generation expansion plan, demand forecast.

3.2.3.3 Fuel Prices

For determining the fuel prices, the value informed by CDEC-SING in the letter CDEC-SING A-0049/2007 was taken as reference, also the historical data published in the CDEC-SING website and the last reference was the price projections published in the document ‘Projected Costs of Generating Electricity’ done by the NEA and IEA, 2006. All the prices are modulated depending on the prices that each generating plant is facing today.

To represent the SING reality about natural gas supply and prices, the natural gas prices were pulled up to a realistic price. These prices have to show the real expectative that exists for the prices of liquefied natural gas on a close to 100% argentine natural gas restriction.

3.2.3.4 Expansion Generation Plan

It is important to establish two different expansion plans. One is the expansion plan that is supposed to be more realistic, showing real investment intentions that will take place in the SING, and the second is a simulation with a coal adapted expansion plan, which assumes additional investment to achieve lower system prices when adapting the system demand to a cheaper technology.

With these two expansion plans is possible to put wind energy projects on two different marginal cost scenarios and thus expect different behaviors on the profitability of the projects as will be seen in the results analysis.

3.3 Energy Generation Potential

To be able to introduce the wind generation into the electrical system simulation model is essential to know the capabilities of the wind farm to generate energy. Basically, this could be achieved by calculating the energy that can be generated from obtained wind speed data and restricted by the characteristics of a specific wind turbine.

In this case, for a numerical evaluation, the turbine used is the Vestas V.82 1.65MW turbine, which has specific characteristics under certain conditions of wind and air density. On this turbine's datasheet is possible to find the power curve and power coefficient for the turbine. Is important to notice that the power curve is calculated for an air density of 1.225[kg/m^3], therefore is essential to extrapolate the power curve to an air density of the site under analysis, which is 0.95[kg/m^3], and being careful with preserving the power coefficient curve.

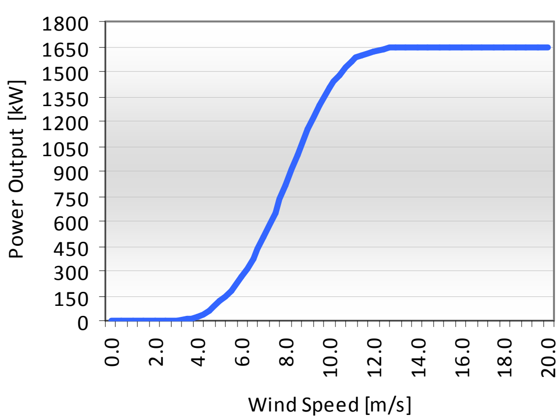

Figure 3-13: Vestas V.82 power curve [Source: Vestas webpage]

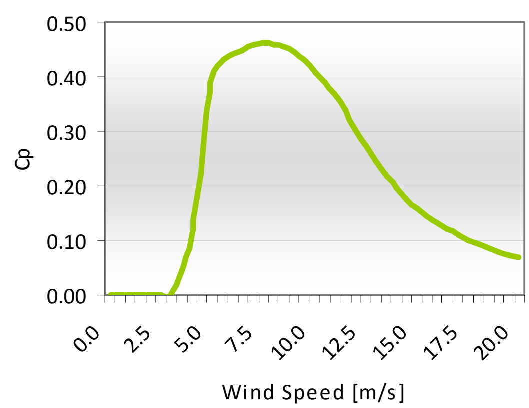

Figure 3-14: Vestas V.82 Power Coefficient [Source: Vestas webpage]

Note that the power coefficient of a turbine represents the efficiency of the turbine under different wind speeds; this means the curve shows how efficient is the turbine converting wind power (P_W) into electricity (P_E) as the following equation shows.

$$C_P = \frac{P_E}{P_W} \tag{3.7}$$

3.3.1 Power Curve Calculation

Hence, for calculating the power curve for the air density of 0.95[kg/m^3] is necessary to calculate the power of wind at the turbine's hub. This can be achieved by using the following equation.

$$P_W = \frac{1}{2} \times \rho \times V^3 \times A \tag{3.8}$$

$$\begin{aligned}
&where,\\
&P_W = Wind\ power\ at\ the\ turbine\ [W]\\
&\rho = Air\ Density\ \left[{}^{kg}\!/\!{}_{m^3}\right]\\
&V = Wind\ Speed\ at\ tubine\ hub\ \left[{}^{m}\!/\!{}_{s}\right]\\
&A = Swept\ area\ of\ the\ rotor\ \left[m^2\right]
\end{aligned}$$

Therefore, taking the power coefficient equation and the wind power equation is possible to obtain the power curve for an air density of 0.95[kg/m^3]. The obtained power curve is shown on Figure 3-15.

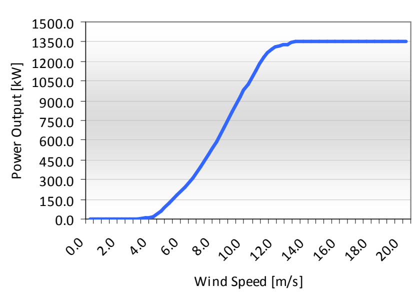

Figure 3-15: Power Curve @ 0.95[kg/m^3]

3.4 Wind Farm Firm Capacity

Considering the calculation methodology included in the appendices for firm capacity is possible to calculate the firm capacity for a wind farm located in the SING. Therefore, to calculate the firm capacity for the wind farm is important to assume that the forced and unforced unavailability include all the hours along the year that the generation of the wind farm is zero not matter the cause of the non generation stage. To calculate the generating hours of the farm, the wind data from WP site was taken and converted to generated power with the turbine's power curve, this because is the actual potential of the turbine to generate power. Hence, the unavailability ratio for a wind farm of any of the three sizes is:

$$U = \left[\frac{T_{OFF}}{T_{ON} + T_{OFF}}\right] = \frac{1140}{8760} = 13.01\% \tag{3.9}$$

Then, for calculating the initial power, the generation histogram was built from the original WP site wind data. Consequently, the calculated initial power is:

$$IP_{wind} = \begin{cases} 69.5MW & \text{, for 173.25MW wind farm} \\ 36.4MW & \text{,for 90.75MW wind farm} \\ 23.2MW & \text{,for 57.75MW wind farm} \end{cases} \tag{3.10}$$

Another assumption necessary to be able to calculate the firm capacity is that the farm does not have any own consumption. Moreover, it is assumed that the system's LOLP does not change whether or not the farm is accounted into the LOLP of the system, subsequently the ratio between the probability with and without the wind farm equals one; therefore the preliminary firm capacity formula reduces to:

$$PFP_{wind} = IP_{wind} \times (1 - U)_{wind} \tag{3.11}$$

where,

$IP_i = \text{Initial Power of 'i'}$

$U\text{=Plant Unavailability Ratio}$

Applying this formula results the following:

$$PFP_{wind} = \begin{cases} 60.46MW & ,\textit{for 173.25MW wind farm} \\ 31.67MW & ,\textit{for 90.75MW wind farm} \\ 20.15MW & ,\textit{for 57.75MW wind farm} \end{cases} \tag{3.12}$$

After calculating the preliminary firm capacity is indispensable to know the sum of the other unit's PFP to be able to calculate the firm capacity. Also, the system maximum demand has to be considered. The PFP of the all the SING power plants was obtained from the "2007 Preliminary Firm Capacity report" published by CDEC-SING on its webpage. Subsequently, the firm capacity for each wind farm size is:

$$FP_i = PFP_i \times \left[\frac{D_{\max}}{\sum_j PFP_j} \right]$$

$$FP_{wind} = \begin{cases} 60.46 \times \left[\dfrac{1773.7}{1833.33} \right] = 58.49MW & ,\textit{for 173.25MW wind farm} \\ 31.67 \times \left[\dfrac{1773.7}{1804.54} \right] = 31.13MW & ,\textit{for 90.75MW wind farm} \\ 20.15 \times \left[\dfrac{1773.7}{1793.02} \right] = 19.94MW & ,\textit{for 57.75MW wind farm} \end{cases} \tag{3.13}$$

Using the real generation obtained from OSE2000 output is possible to calculate the correction ratio due to transmission and other system limitations. Including these limitations through the correction ratio the final firm capacity is:

$$FP_{wind} = \begin{cases} 58.49 \times (1 - 0.0221) = 57.20MW & ,\textit{for 173.25MW wind farm} \\ 31.13 \times (1 - 0.0221) = 30.44MW & ,\textit{for 90.75MW wind farm} \\ 19.94 \times (1 - 0.0221) = 19.50MW & ,\textit{for 57.75MW wind farm} \end{cases} \tag{3.14}$$

3.4.1 Firm Capacity Income

From the firm capacity values found in the results in (3.14) is possible to estimate the payment received from firm capacity. For this, the power node price obtained from the simulation model is used. Basically the node price [US$/MWh] is multiplied by the amount of peak hours to be paid, which is 1284 for the SING case. From this calculation a proper power node price is obtained [US$/MW], therefore is possible to multiply the obtained valued by the amount of firm capacity corresponding to the wind farm sizes under analysis.

$$Payment = FP_{wind}\left[MW\right] \times NP_{Power}\left[{}^{US\$}\!\big/_{MWh}\right] \times 1284 \tag{3.15}$$

3.5 Emission Displacement

The emission displacement is an important factor when it comes to analyze the feasibility of renewable energy installation because, depending on where in the world the renewable energy project is installed could be eligible to become a CDM project. The Clean Development Mechanism (CDM) is an arrangement under the Kyoto Protocol allowing industrialized countries with a greenhouse gas reduction commitment (Annex 1 countries) to invest in projects that reduce emissions in developing countries as an alternative to more expensive emission reductions in their own countries. Therefore, any renewable energy project developed in Chile is eligible as a CDM project and hence is capable of generating Certified Emission Reductions (CERs, equivalent to one tonne of CO2 displacement), and thus perceive a certain income due to this.

For this matter, a method to calculate the emission displacement was developed to be able to calculate the emission displacement in the SING (Keith, Biewald, Sommer, Henn, & Breceda, 2003; Keith, Biewald, & White, 2004). This technique has two ways to be applied; one is assuming that the displaced emission is unique and the other is generalizing the first one by considering the possibility of displacing more the one technology.

3.5.1 Emission Displacement Calculation

To calculate the emission displaced by a certain renewable technology is necessary to know the generation scheme (merit list) of the system where the renewable energy plant is planned to be located. Basically real generation data has to be taken and with this generate a Load Duration Curve (LDC). This is done with the purpose of defining the technology mix in the system’s real demand and also establishing the demand levels where each technology starts and ends its generation. Figure 3-16 shows the LDC for a generic electrical system with its technology mix demand levels.

On the LDC, any technology located above the minimum demand is considered to be a marginal technology. These technologies work as marginal technologies at some stage of the year, or of the period of analysis, and are the first technologies displaced by a potential renewable energy generation. As shown on Figure 3-16, with the LDC is possible to define the demand ranges where each technology generates, for this case, this demand levels were numerated starting from the cheapest to the most expensive technology.

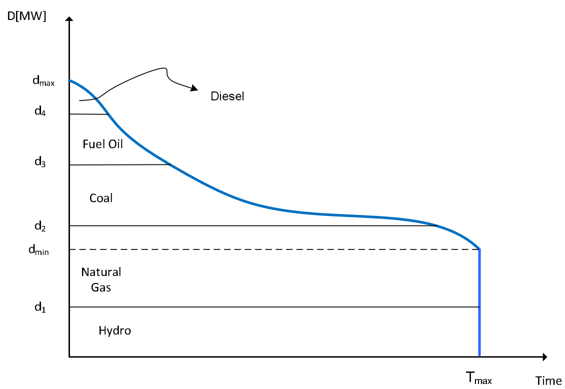

Figure 3-16: Load Duration Curve and Technology Mix

The previous load duration curve is a generic one. The SING year load duration curve, given the high industrial load component, is different, as shown on Figure 3-17. It is flatter, includes more technologies, and it is essentially thermal.

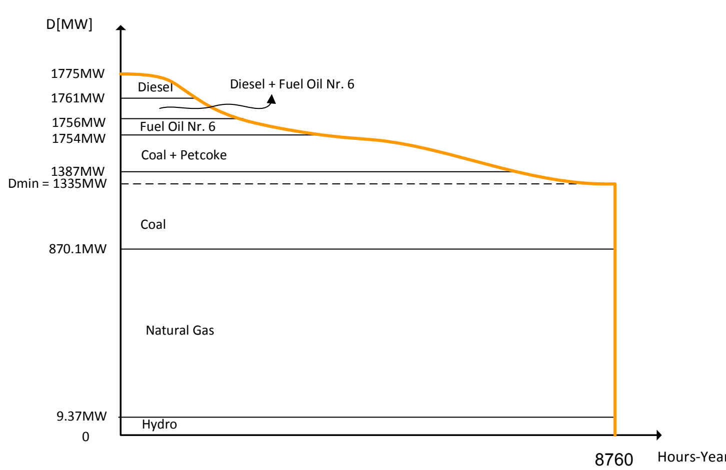

Figure 3-17: Year Load Duration Curve and Technology Mix at the SING, 2005

By knowing the technologies included on a specific system, it is possible to create a marginal emissions curve (Figure 3-18), which is obtained from the demand levels established on Figure 3-16. The marginal emission level has to be obtained per technology depending on the characteristics of the power plants present in the electrical system. The marginal emission per technology is obtained as follows.

$$E_{mg} = C_S \times LHV \times EF \tag{3.16}$$

where,

E_{mg} = *Marginal Emission* $\left[{}^{ton CO_2}\!/_{MWh} \right]$

C_S = *Specific Consumption* $\left[{}^{kg}\!/_{MWh} \right]$

LHV = *Lower Heating Value* $\left[{}^{Kcal}\!/_{kg} \right]$

EF = *Emission Factor* $\left[{}^{ton CO_2}\!/_{Kcal} \right]$

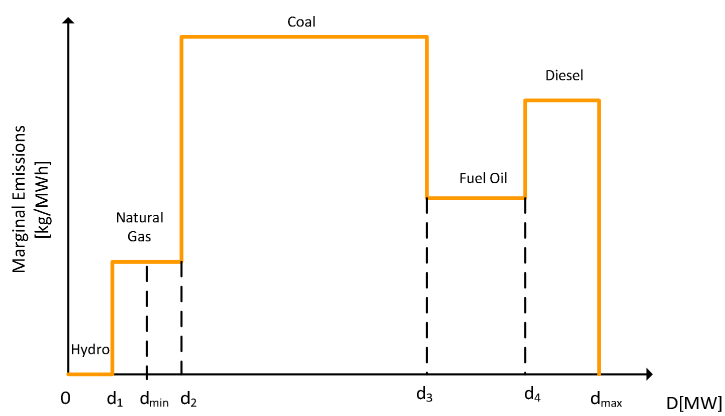

Figure 3-18: Marginal Emissions Curve

As mentioned before, there are two different cases when it comes to calculating the emission displacement. These two cases depend on the sizes of the generating plant installed and the characteristics of the marginal technologies of the electrical system under analysis. Hence, the two cases are:

- *Displacement of a unique technology:* This case occurs when the marginal technology has a large demand interval to cover and/or the renewable energy technology penetration level is small.
- *Multi-technology displacement:* This situation usually occurs when the marginal technologies are too atomized and/or when there is a large amount of renewable energy generation.

The displacement calculation technique of a unique technology (marginal technology) will be explained first and then this technique will be generalized into the multi-technology approach.

3.5.1.1 Marginal Technology Displacement

As stated before, in the case the renewable energy generation is capable of displacing only one technology, which is the marginal technology at the moment of analysis. To be able to calculate the amount of emissions displaced by a certain renewable energy technology is indispensable to estimate the level of displaced emissions on a specific time of period of time. For this, a marginal emissions curve function of time is needed. To achieve this, the system's demand curve is needed. Once this curve is obtained, is necessary to take the demand levels shown on Figure 3-16 and the marginal emissions on Figure 3-18.

Then, the demands levels obtained in the LDC are superposed on the demand curve to be able to know which technologies are used to generate on a given time. With this the marginal emission for each instant is defined and then is possible to know the value of the marginal emission for the displaced technology. Is important to remember that the level of emissions of marginal emission is obtained marginal emission curve, which is function of the demand level.

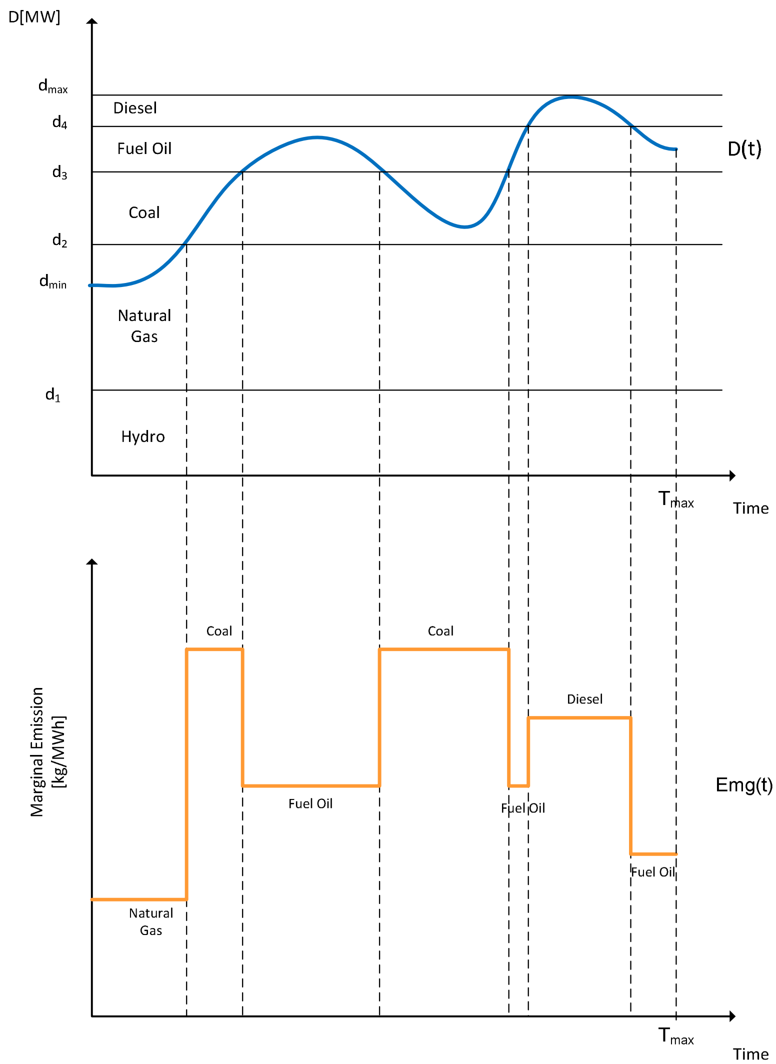

Figure 3-19: Marginal Emission as Function of Time

To obtain the emission displacement, a certain renewable generation level has to be assumed if the calculation is done a priori or consider a measured generation if is done after a period. A generic generation curve is shown by Figure 3-20; where the variability could be owed to the type of technology, if the technology is wind energy for example there will be a more intermittent generation scheme. The generation curve will be defined as W(t).

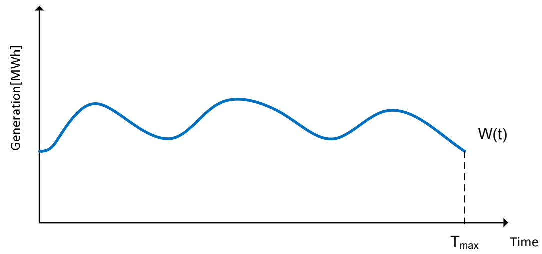

Figure 3-20: Renewable Energy Generation

Considering the marginal emissions curve as function of time, Emg(t), is possible to determine the emission displacement level done by the renewable energy technology. Clearly, to apply this method is assumed that the renewable technology generates without and scheduling or dispatching control.

Therefore, the displaced emission as function of time is:

$$E(t) = W(t) \times Emg(t) \tag{3.17}$$

Then, the total emissions for a determined period will be:

$$E = \int_{t_1}^{t_2} \left[W(t) \times Emg(t) \right] dt \tag{3.18}$$

Nevertheless, is possible to calculate the average emission value for a specific period, this expression could be identified as the "Period's Emissions Factor". This factor can be calculated as shown below:

$$\overline{Emg} = \frac{\int_0^T W(t) \times Emg(t)\, dt}{\int_0^T W(t)\, dt} \tag{3.19}$$

Is important to know that in real life data is not continuous and a discrete form of the formulas mentioned above have to be applied to perform the calculation. Hence, the discrete formulas to calculate the emissions displacement are:

$$E[t] = W[t] \times Emg[t] \tag{3.20}$$

$$E = \sum_i \left(W[i] \times Emg[i] \right) \tag{3.21}$$

$$\overline{Emg} = \frac{\sum_i \left(W[i] \times Emg[i] \right)}{\sum_i W[i]} \tag{3.22}$$

3.5.1.2 Multi-Technology Displacement

When there is a higher penetration of renewable energy (RE) is more likely to displace more than one technology on one instant, this means that at a certain time the generation of RE is higher than the amount of generable amount of marginal technology. When this happens is essential to generalize the technique explained before to be able to account the displacement of more than one technology.

To calculate Emg(t), first is necessary to know how many and which technologies is the RE generator displacing. To achieve this, two different emission technology displacement curves have to be defined; one is the curve obtained from the first technologies displaced, which will be defined as HT(t) and the other is the curve that represents the last technologies displaced, this curve will be defined as LT(t).

- *HT(t) calculation:* to obtain this function is necessary to perform the same procedure as in the situation when only one technology is displaced, this means that is required to do what is shown on Figure 3-19. This means that HT(t) equals Emg(t) for the case of one technology.

- *LT(t) calculation:* for this function additional calculations are required. First is necessary to obtain what will be called *reduced demand ($D_{red}(d)$)*, this demand is obtained from the difference the system's demand D(t) and the RE generation W(t) as shown on equation (3.23).

$$D_{red}(t) = D(t) - W(t) \tag{3.23}$$

Graphically the reduced demand is shown on Figure 3-21.

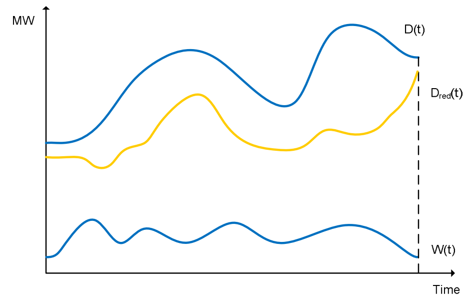

Figure 3-21: Reduced Demand

Then, after obtaining the reduced demand is possible to obtain LT(t) using the technique used for one technology but instead of doing it for D(t), it will be applied for $D_{red}(t)$. The resulting curve is shown on Figure 3-22.

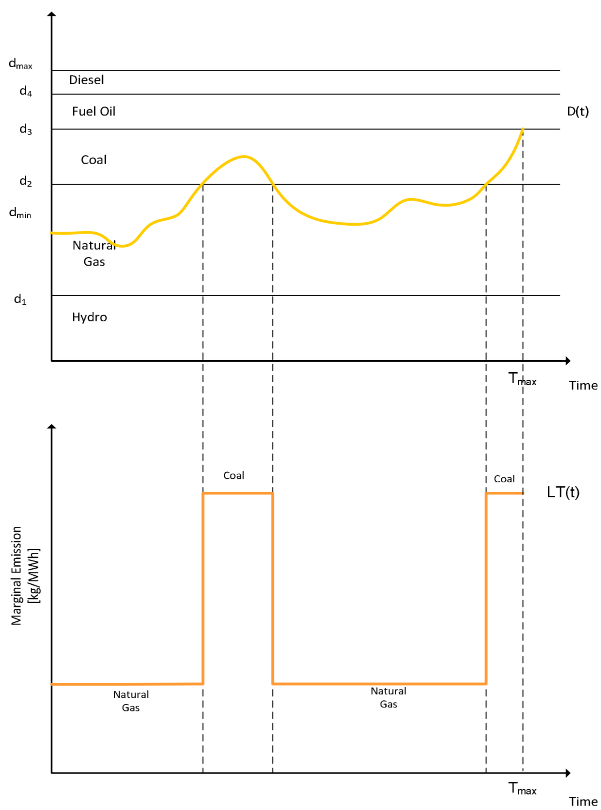

Figure 3-22: LT(t) Calculation

After obtaining both curves, HT(t) and LT(t), is necessary to compare both curves to see if more than one technology was displaced. To achieve this, both curves have to be superposed; the curves will be different on times where more than one technology is displaced and HT(t) will equal LT(t) on periods or instants where there was only one technology displaced. Figure 3-23 shows both curves superposed

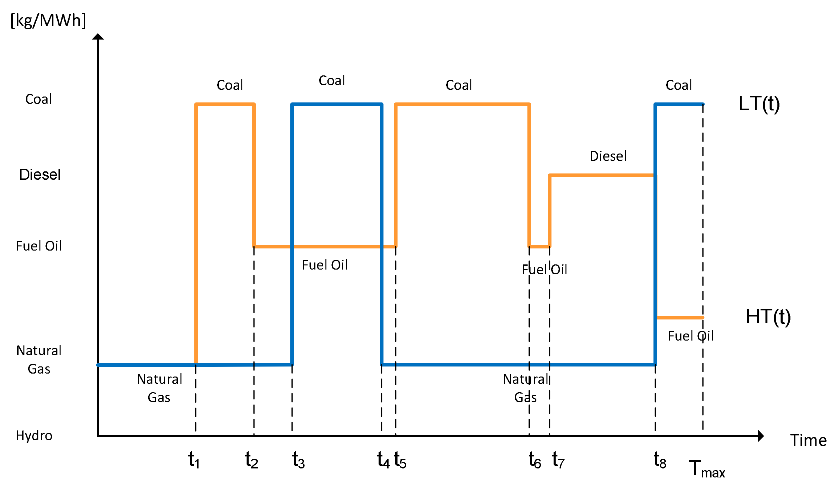

Figure 3-23: LT(t) and HT(t) superposed

To determine how many and which technologies are displaced the dispatch merit list is needed, this means, the merit list used to build the LDC on Figure 3-16. For the generic system under analysis the merit list is as follows:

1. Hydro
2. Natural Gas
3. Coal
4. Fuel Oil
5. Diesel

Considering the dispatch order specified above is possible to find out how many technologies are displaced and identify each one of them. Figure 3-23 shows the different time intervals where both curves present some change. With this time intervals and using the list of dispatch order is possible to build a table that shows the technologies displaced on each interval. Is good to remember as a way to check the table, that the first displacement is represented by HT(t) and the lower displacement by LT(t).

Table 3-2: Displacement per Period

Period	First Displacement	Second Displacement	Third Displacement	Forth Displacement
0-t1	Natural Gas			
t1-t2	Coal	Natural Gas		
t2-t3	Fuel Oil	Coal	Natural Gas	
t3-t4	Fuel Oil	Coal		
t4-t5	Fuel Oil	Coal	Natural Gas	
t5-t6	Coal	Natural Gas		
t6-t7	Fuel Oil	Coal	Natural Gas	
t7-t8	Diesel	Fuel Oil	Coal	Natural Gas
t8-tmax	Fuel Oil	Coal		

Therefore, in now possible to calculate the emissions function E(t), which will be able to represent all the displaced technologies. Hence, the function E(t) is defined as follows:

$$E(t)= \left[D(t)-d_i\right]\times Emg_{i+1} + \begin{cases} \sum_n \left(\left\{ \left[d_k - d_{k-1} \right] \times Emg_k \right\}\Big|_{i \geq k \geq j} \right)_n & \text{, if a technology is completely displaced} \\ 0 & \text{, if no technology is completely displaced} \end{cases} + \left[d_j - \left(D(t) - W(t) \right) \right] \times Emg_j \qquad (3.24)$$

$$
\begin{aligned}
&where, \\
&D(t) && = System's\ demand \\
&W(t) && = Renewable\ energy\ generation \\
&Emg_x && = Technology\ 'x'\ marginal\ emission \\
&d_i && = Maximum\ demand\ level\ of\ technology\ 'i' \\
&n && = Number\ of\ completely\ displaced\ technologies \\
&j && = Last\ displaced\ technology
\end{aligned}
$$

To calculate the total emissions and the emission factor for a period of time the following formulas have to be used:

$$E = \int_{t_1}^{t_2} E(t)\,dt \tag{3.25}$$

$$\overline{Emg} = \frac{\int_{t_1}^{t_2} E(t)\,dt}{\int_{t_1}^{t_2} W(t)\,dt} \tag{3.26}$$

3.5.2 Methodology Applied to the SING with Wind Energy Inclusion

To apply the multi-technology emission displacement methodology in the SING is necessary to calculate the marginal emissions per technology because this information is not available in the electrical system. Thus, applying equation (3.16) to the each SING power plant and then obtaining a weighted average per technology the results are:

Table 3-3: Marginal Emissions per Technology in the SING

FUEL TYPE	SC [kg/kWh]	LHV [Kcal/kg]	EF [kg CO2/TJ]		Marginal Emissions [ton CO2/MWh]
COAL	0.4398	6000	94600		1.044373
COAL + PETCOKE	0.4387	7500	96050		1.322334
DIESEL	0.2229	10355	73300		0.707907
DIESEL + FUEL OIL	0.2477	10000	73700		0.763725
FUEL OIL Nr.6	0.2566	9975	74100		0.793653
NATURAL GAS	0.2278	8407	56100		0.449508

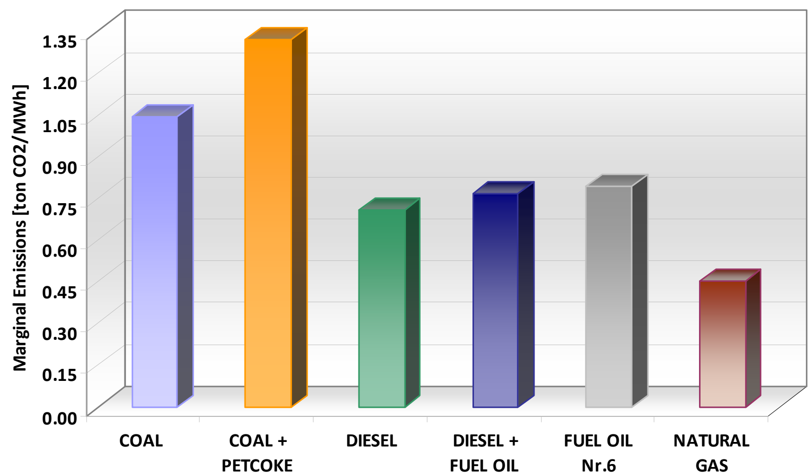

Figure 3-24: Marginal Emissions per technology in the SING

After obtaining the emissions per technology for the SING, three different scenarios of emission displacement were analyzed. These three cases are:

- *System before curtailment:* For this case the data used is historical data obtained from CDEC-SING for years before curtailment.
- *System with curtailment:* In this case the data used was data from the CDEC-SING for the last months (second semester of 2007) were curtailment reaches almost 100%.
- *Coal adapted system:* For a coal adapted system was assumed that the natural gas situation only improves in a very small way and all the remaining not covered demand is supplied by coal-fired plants installed in the future.

Each situation is schematized with a chart that shows the generation matrix distribution for each technology.

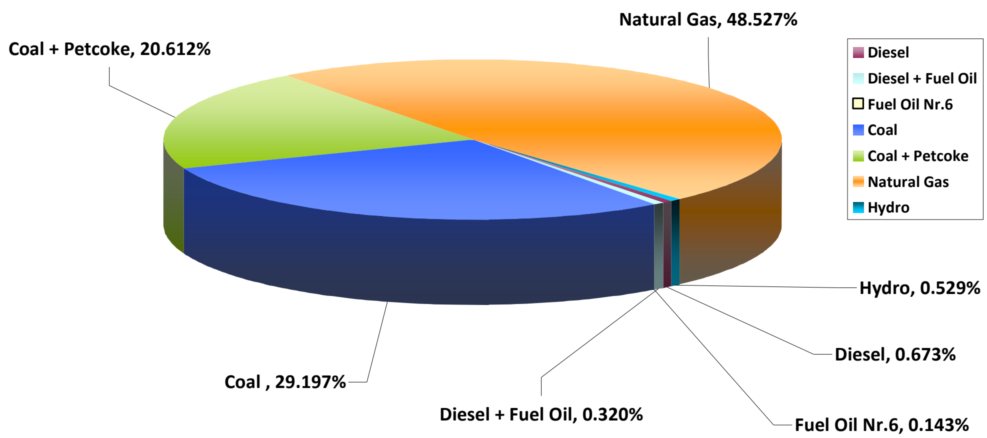

Figure 3-25: Technology Mix before Curtailment

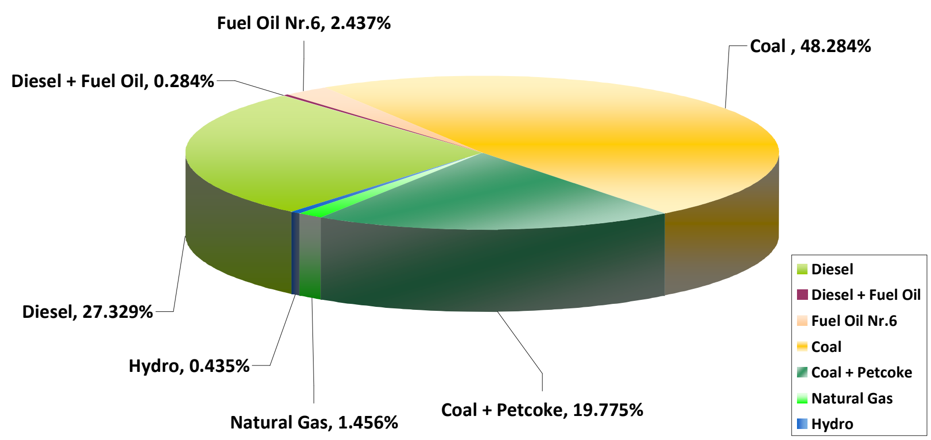

Figure 3-26: Technology Mix under Curtailment

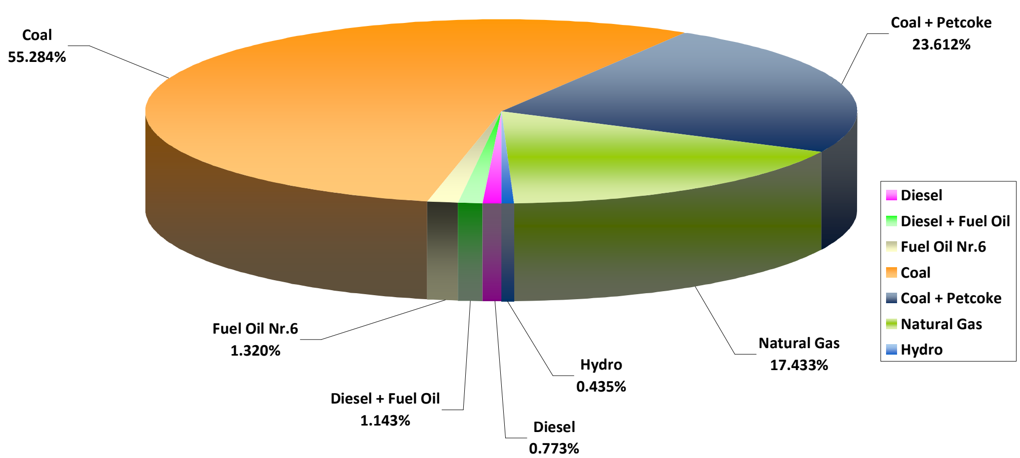

Figure 3-27: Technology Mix for Coal Adapted System

Also, the emissions were calculated for three different levels of wind energy penetration. These penetration levels are:

- 57.75MW.
- 90.75MW.
- 173.25MW.

Therefore, the emissions will be calculated for 9 different cases. For each technology mix case without wind inclusion, the LDC was calculated, defining the dispatch order, demand levels for every situation and the maximum and minimum demand.

Table 3-4: Demand levels for each calculation case [MW]

	Fuel Type	Before Curtailment	Curtailment	Coal Adapted
dmax	Diesel	1773.70	1738.30	1738.30
d6	Diesel + Fuel Oil	1761.76	1263.24	1724.86
d5	Fuel Oil Nr.6	1756.08	1258.30	1704.99
d4	Coal	1753.55	1215.93	1682.04
d3	Coal + Petcoke	1235.68	376.61	721.05
d2	Natural Gas	870.09	32.87	310.60
d1	Hydro	9.37	7.57	7.57

Table 3-5: Max and Min Demand [MW]

	Before Curtailment	Curtailment	Coal Adapted
D min	986	1335.4	1335.4
D max	1773.7	1738.3	1738.3

Considering real wind data and estimating the generation that each wind farm will have in case of being installed in the SING the W(t) is:

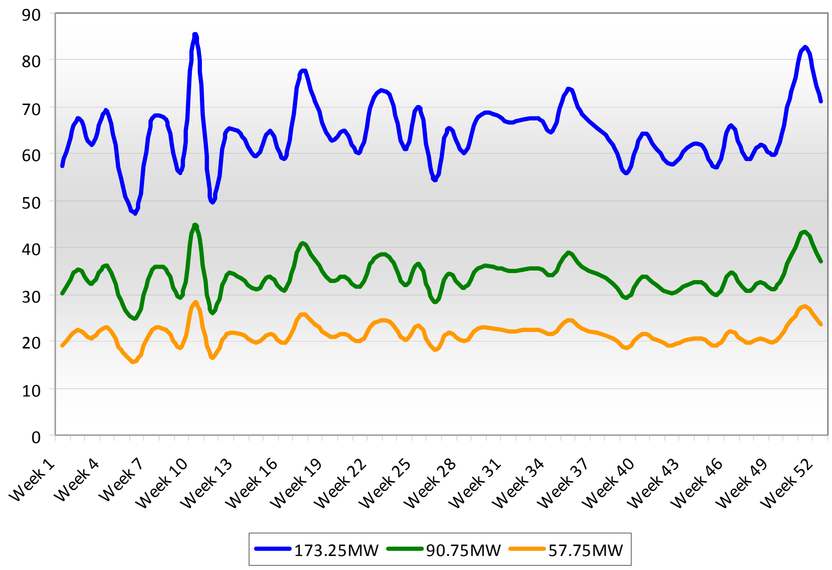

Figure 3-28: Average Weekly Generation [MW]

With all this data gathered from the SING is possible to apply the method to obtain the marginal emission and total emission for a year and with that be able to estimate the income that each plant size would receive in case of being installed in the SING. Therefore, applying the emission displacement technique in the SING the following results are obtained:

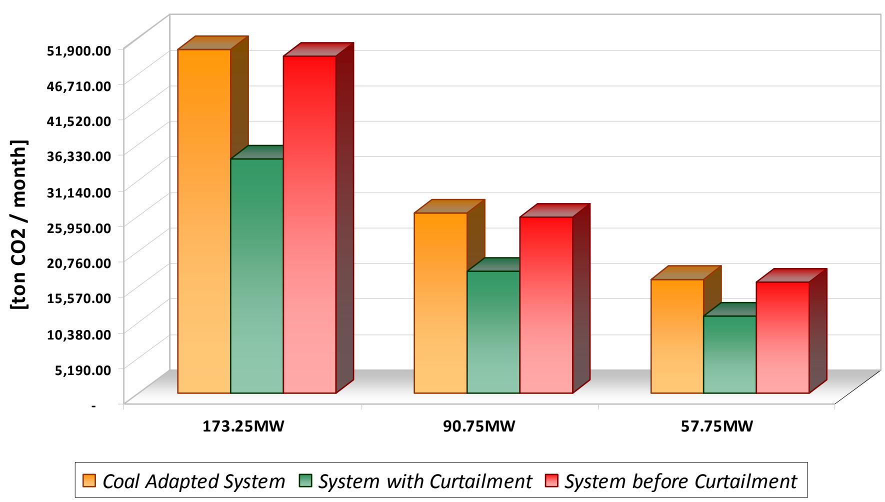

Figure 3-29: Monthly Emission Displacement in the SING

$$Coal\ Adapted\ System = \begin{cases} 50,277.70\left[ton\ CO_2/month\right] & ,173.25\ wind\ farm \\ 26,335.94\left[ton\ CO_2/month\right] & ,97.75\ wind\ farm \\ 16,759.23\left[ton\ CO_2/month\right] & ,57.75\ wind\ farm \end{cases}$$

$$System\ with\ Curtailment = \begin{cases} 34,282.53\left[ton\ CO_2/month\right] & ,173.25\ wind\ farm \\ 17,957.51\left[ton\ CO_2/month\right] & ,97.75\ wind\ farm \\ 11,427.51\left[ton\ CO_2/month\right] & ,57.75\ wind\ farm \end{cases}$$

$$System\ before\ Curtailment = \begin{cases} 49,300.59\left[ton\ CO_2/month\right] & ,173.25\ wind\ farm \\ 25,769.29\left[ton\ CO_2/month\right] & ,97.75\ wind\ farm \\ 16,386.38\left[ton\ CO_2/month\right] & ,57.75\ wind\ farm \end{cases}$$

3.6 Energy Purchase Contract

On many electricity markets there is the possibility of selling generated energy under a bilateral energy purchase contract. Usually this contract reflects what the generating plant expects to receive from its generated energy. This value, in a competitive market, is the calculated marginal cost of the generating plant. In the case of a wind farm would be the cost of generating due to investment recovery and additional incomes perceived by the generating plant. Therefore, the price established for a contract would be:

$$P_{contract} = C_{development} - FP - CER \tag{3.27}$$

where,

$P_{contract}$ = *Price of Purchase Contract*

$C_{development}$ = *Wind Development Cost*

FP = *Firm Power Payment*

CER = *Certified Emission Reduction Payment*

On equation (3.27) the wind development costs represents the amount of revenues per MWh that the wind farm should receive to be economically feasible, therefore this cost would be the contract price in case of not receiving firm capacity and CERs payment.

3.6.1 Contract Price in the SING

To calculate the contract price that a wind project would establish in the SING, was assumed that the annual amount of revenues received for Emission Reduction Certificates is constant. Also, for the case of the Firm Capacity revenues, the highest value obtained from the system simulation was considered to be the value for contract price calculation, putting the wind farm project under the worst case scenario, which means the lowest value that a wind project in the SING could offer. Consequently, the value for the energy purchase contract varies depending on the size of the wind farm and on which is the wind farm connection node. Also, for each simulated case there is a different power payment. Therefore, for the simulation there in one contract price for each simulated scenario. When the wind installed capacity is bigger, the additional payment (Firm power and CERs) is larger and therefore the contract is lower.

3.7 Investment Feasibility Analysis

Non-conventional renewable energy investments in the SING is an absolutely new aspect for this interconnected system and with the changes on the law has become of a great interest of many companies. A methodology for analyzing how feasible the installation of a renewable energy project is, specifically wind energy, will be explained now (Botterud & Korpas, 2004; Denny et al., 2006; Denny & O'Malley, 2006; Moreno, Mocarquer, & Rudnick, 2006). This analysis will be separated into two global aspects: the Economic Viability and the Regulatory Incentives; this because the economic viability could show that investing on wind energy is feasible although the law could not be giving incentives to invest on this kind of technologies.

3.7.1 Economic Viability

3.7.1.1 Initial Feasibility Analysis

The initial feasibility has to be done, before running a full evaluation, to know if the project would survive. To do this analysis, is necessary to have an estimation of the future system marginal costs, which in this case is done through running a simulation model of the SING. Moreover, is necessary to calculate the wind development cost assuming that will be installed in the system under study.

With both data is possible to compare the behavior of the marginal costs with the development cost. This comparison will only show if the prices in the system are high enough to be able to install a wind farm. Here, additional revenues are not considered, this means that the wind investment is demanding greater system marginal costs than what the project really needs to survive.

3.7.1.2 Economic Evaluation

Here a classical Net Present Value evaluation is done, analyzing different simulation cases to be able to know is the project can take place under the system prices reality and establishing appropriate variables to sensibilize.

3.7.1.3 Marginal Income Analysis

To generate a clearer view of the economic viability of a wind project, the marginal income, which will be explained later, is compared with the system marginal cost to observe the actual survivability of wind projects in the SING. Basically the marginal income has to be equal or above the system marginal cost to be economically viable.

3.7.2 Regulatory Incentives

3.7.2.1 Law Incentives Analysis

Through the modifications of the electricity law, the government intends to promote new investments on non-conventional renewable energy (NCRE) technologies. To see how effective the law will be, a decision analysis is done where the project NPV is compared with the law penalty NPV and with this be able see if the decision is to invest in the worst case scenarios. As will be explained, the investment decision is positive when the project NPV is greater than the law penalty NPV, considering that the law now obligates the generating companies to generate a 5% of its generation with NCRE technologies.

Also, the incentives will be analyzed from a large client point of view, this to observe real incentives that the law generates for these clients to engage contracts with generating companies that have or will install renewable energy technologies, in particular wing energy generators.

4 SIMULATION RESULTS AND ANALYSIS

4.1 Initial Feasibility Analysis

4.1.1 Wind Project Development Cost

The development cost on any project comes with great importance to see the level of prices the project has to face to have a chance of being profitable. On a first look, the system price (marginal price) evolution can be compared to the development cost each year to see if is worth to generate a bilateral contract with a wind energy plant. Clearly is much more reliable to study the real behavior of the project through a cash flow analysis, which is done in this investigation as well.

To calculate the development cost of the project is necessary to consider all costs included on installing the wind farm in the WP site. The life defined to calculate the cost is 20 years and a WACC of 10%. Also, as an only Chilean situation, the revenue tax was included and considered to be 17%. This is done because of the tributary benefits that come with paying the tax in relation with the costs. Therefore, to calculate the development cost the following formula was used.

$$C_{development} = \frac{A + (1-17\%) \times C_T - 17\% \times D}{1-17\%} \tag{4.1}$$

where,

$C_{development}$ =*Development Cost* $\left[{US\$}/{MWh}\right]$

A =*Investment Annuity* $\left[{US\$}/{MWh}\right]$

C_T =*Total Costs (including Variable and Fixed Costs)* $\left[{US\$}/{MWh}\right]$

D =*Assets Depreciation* $\left[{US\$}/{MWh}\right]$

All investment costs were obtained from Vestas for a V.82 turbine. These costs include needed items, construction costs, freight, installation supervision labor and maintenance costs. In the case of fixed costs, they were separated into to categories; one is the fixed operational costs, which represent 1% of the investment annuity excluding the construction costs; the second category are the administration and sales fixed costs, which represent 1.5% of the investment annuity excluding the construction costs. In relation to the variable costs, standard wind industry costs were considered. Table 4-1 shows the development costs for the three wind farm sizes evaluated in this investigation (EWEA, 2004; Vestas, 2007).

Table 4-1: Wind Farm Development Cost

		Wind Farm [MW]		
		173.25	90.75	57.75
Life	Years	20.00	20.00	20.00
WACC	%	10%	10%	10%
Revenue Tax	%	17%	17%	17%
Cap Cost	US$/MW	2,349,714.30	2,382,998.72	2,422,940.03
Capacity Factor	%	33.96%	33.96%	33.96%
Annuity	US$/MW	275,996.56	279,906.14	284,597.63
Generated Energy	MWh-year	515,334.00	269,940.00	171,779.00
Depreciation	US$/year	117,485.71	119,149.94	121,147.00
	US$/MWh	0.23	0.44	0.71
Fixed Costs	US$/MWh	1.76	1.77	1.78
Variable Cost	US$/MWh	10.00	10.00	10.00
Annuity	US$/MWh	92.79	94.10	95.68
Wind Development Cost	**US$/MWh**	**123.51**	**125.05**	**126.91**

When calculating the development cost is possible to observe that the cost decreases as the size of the wind farm increases. This expresses the existence of Economies of Scale. In a further section of this thesis is shown how economies of scale related to marginal incomes change when the electrical system imposes its restrictions such as transmission limit.

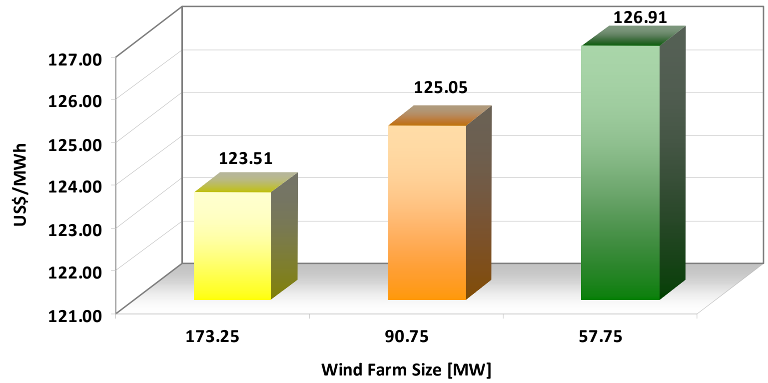

Figure 4-1: Wind development cost

4.1.2 System Marginal Costs

To obtain the system marginal costs the model was ran for 20 different cases, these cases were specified in the model description section. Each simulation output gives the marginal cost evolution for the 15 years, which is the amount of years the model was asked to simulate. The system marginal cost in the SING is considered to be the marginal cost on Crucero 220, which is the reference node for the whole system.

4.1.2.1 Normal Demand Scenario

In the short term, the marginal costs behaved as expected. They went up as the system experienced natural gas curtailment from Argentina. Then, the system started adapting to coal through projects included from 2010. Also, the system is expected to start receiving LNG, which translates into a lower price but not as low as generating with coal, at least at the beginning, when the LNG should be a dearer than the price that Chile used to have on RNG (Argentine Natural Gas). On the last years of simulation the price tends to stabilize on a value; this happens because from the 10th year the fuel prices were assumed to be constant as is impossible to have a better prediction for fuel prices on more than 10 years.

For the three connection nodes the behavior of the marginal costs is the same and as expected. On the other hand the values are not that different either. Between the values there is only a variation of less than a U.S. dollar. Therefore, the prices behavior will now be shown considering only one connection node (Calama 110). All values are included in the appendix section.

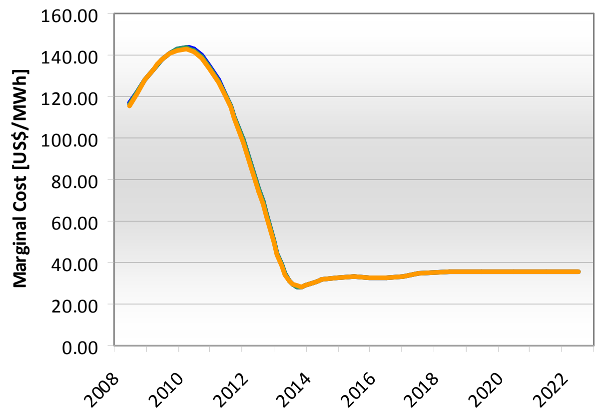

Figure 4-2: System Marginal Cost - Calama 110 Connection, Normal Demand, Coal Adapted

Figure 4-2 shows the costs values and behaviors for three different size wind farm connected to Calama 110 with an expansion plan that adapts the system to coal-fired plants. The large variation of the value during the first years are owed to the curtailment existing in the SING until the coal-fired power plants start working, which starts happening from 2011. It is also possible to observe that with higher wind penetration the system marginal costs tent to go down, this effect will be analyzed on a further section. For a system adapted to coal, the system marginal costs (prices) are expected to be lower because the price dominating the market will be the coal marginal cost.

In this case the system adapts itself to coal-fired plants, which is a cheaper technology, from 2010 starts stabilizing the price to a price close to coal marginal cost. This scenario is less favorable to install more expensive technologies, such as wind energy.

4.1.2.2 High Demand Scenario

In the case where the demand grows rapidly, without the system being able to adapt to cheaper technologies, the marginal costs go up. As it was expected, the marginal costs went up on the first couple of years, where the Argentine Gas curtailment and demand growth were the main responsibles. As seen on Figure 4-3, after the first marginal cost peak, there is a cost reduction; this is owed to the incorporation of coal-fired generators during that period. Following to that period the cost goes up because the cheap generators (coal-fired) are not capable of keeping the prices down and the system does not have enough time to adapt its self to a cheaper technology, which is coal for this case.

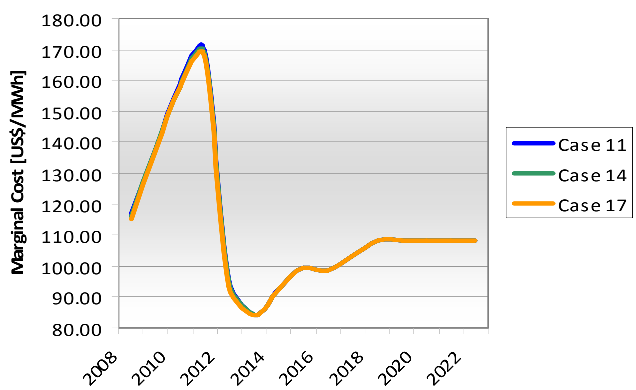

Figure 4-3: System Marginal Cost - Calama 110 Connection, High Demand, Coal Adapted

Figure 4-3 also shows a slight marginal cost reduction around 2016, this is because of the inclusion of the last stages of a coal-fired generating plant, which is not large enough to pull the system marginal costs back down and because the demand keeps growing at a vegetative state. The cost goes back up reaching US$110 per MWh. Clearly these costs are not good for the consumers, but good for the generators side as they perceive higher revenues.

In this case the system is capable of pulling the prices down after 2010, this due to the amount of investment in coal-fired plants. The system does not adapt totally to coal and thus the price does not stay as low as should be. Figure 4-4 shows the difference between the Normal and High Demand scenarios for the base case without wind energy inclusion and with a system adapted to coal-fired plants.

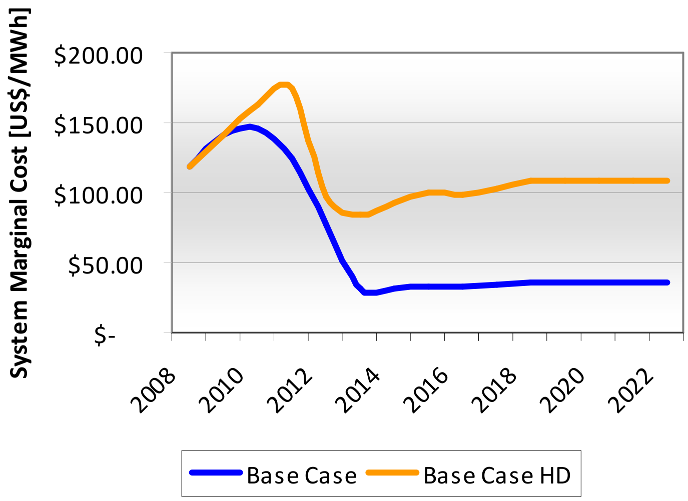

Figure 4-4: Normal and High Demand Base Case Comparison, Coal Adapted

4.1.2.3 SING Marginal Price Variation

From the results obtained from the electrical system model simulation (Kas Ingeniería, 2005), is possible to compare these values to be able to obtain the variation of the system marginal prices caused by the wind energy inclusion. The values taken as reference are two sets of values; one set is the values from a simulation without any wind inclusion and considering a normal demand growth which is considered to be more probable to happen in the future if a big mining facility does not appear suddenly; the other set of values are the ones obtained from the simulation of a case without wind but with a system facing a huge increase on its demand caused by an incorporation of a mining project, which would have a similar consumption scheme to the mining facilities already installed.

On the model, there were three connection nodes considered as potential substations for the wind farm connection. Due to system characteristics, the variations of the system marginal prices for a same size wind farm vary from node to node but not considerably. Moreover, the behavior of the variations throughout the years is the same. To analyze the results, only the Calama 110 connection node will be shown.

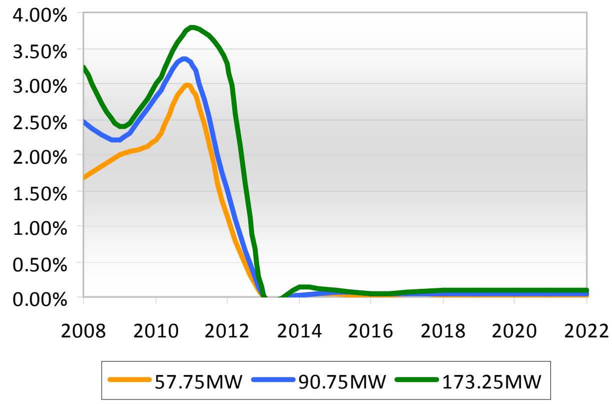

Figure 4-5: CMg Reduction on Calama 110 – Normal Demand – Adapted System

Figure 4-5 shows the reduction of the marginal price produced by three different wind farm sizes in the SING. These variations decrease on the last years of the simulation because wind energy does not displace any technology and most generation is done through coal-fired plants. By analyzing the curves is possible to say that when the wind penetration is higher the reduction of the marginal cost is higher. The cost reduction is caused only because of an inclusion of a cheaper technology and the assumption of a system that does not suffer instability costs due to the intermittency of the wind source; this can be assumed due to the amount of wind included in the simulations. For even higher wind penetration there could be a cost increase instead of a cost reduction, as has been observed in some parts of the world (MMA, 2003).

As mentioned before, other systems in the world have encountered an increase of the prices when facing high levels of wind penetration. This level can not be determined, because depends on the characteristics of each system and how expensive is to keep higher amounts of spinning reserve.

4.1.2.4 Marginal Costs Reduction Discussion

Observing the variations suffered by the system every year is possible to see that the marginal cost reductions depend on the systems prices (marginal costs), which depends on the marginal generating technology. The first years the system prices tend to be high because of curtailment situations; the system is forced to generate with expensive technologies and facing big variation on its price. When coal-fired plants start generating, they pull the prices down and this causes for the wind energy generators to have less effect on the system prices.

High prices in the system are caused by generating electricity with expensive technologies. When this happens, wind energy generation contributes to lower these prices by displacing expensive generation in some periods. On the SING, high prices are caused by generating with diesel and lower prices are caused by generating with coal-fired plants or cheaper technologies.

On the last years of the simulation, the system price stabilizes on prices close to coal marginal prices because of a system adaptation. Because the system is adapted to coal, wind generation is not big enough to pull prices down and hence the reduction of the system marginal cost is close to zero.

4.1.3 System Marginal Cost vs. Wind Development Cost

As a preliminary investment feasibility analysis is possible to compare the system marginal cost and the wind development cost. This comparison will only show if the prices in the system are high enough to be able to install a wind farm. Here, additional revenues are not considered, this means that the wind investment is demanding greater system marginal costs than what the project really needs to survive. Also, here the marginal cost used were obtained from

The SING was simulated, as mentioned before, for different amounts of wind penetration, two different demand scenarios (Normal and High), and two different expansion plans. For the case of high demand and non-adapted system, prices are very high, as seen on previous sections. Due to this is clear that a wind project would survive under these kinds of prices. In the cases where the system is adapted to coal-fired plants the prices are very low and a wind project would not be economically viable, at least from this first look.

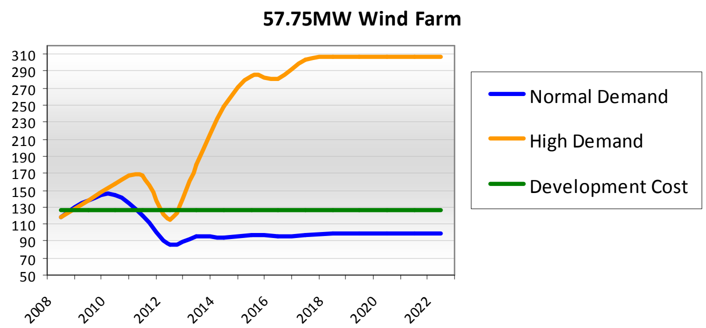

Figure 4-6: System Marginal Cost vs. Development Cost Comparison – Not Adapted

Figure 4-6 shows the system price evolution vs. the winds development cost for a 57.75MW wind farm connected to Calama 110 in the SING. As is possible to observe, the system marginal costs for the high demand scenario is much greater than the development cost most of the time, this represents clear incentives to invest in case of a scenario where the system is facing a high demand and does not have time to adapt to a cheaper technology.

For the case of normal demand there is an opposite situation, the system marginal cost tends to go under the development cost most of the time. Figure 4-7 shows the difference between the wind development cost and the system marginal costs. From 2011 the system costs go below the development cost, which could mean that if the wind farm sells its energy at system marginal cost it would simply not be economically feasible.

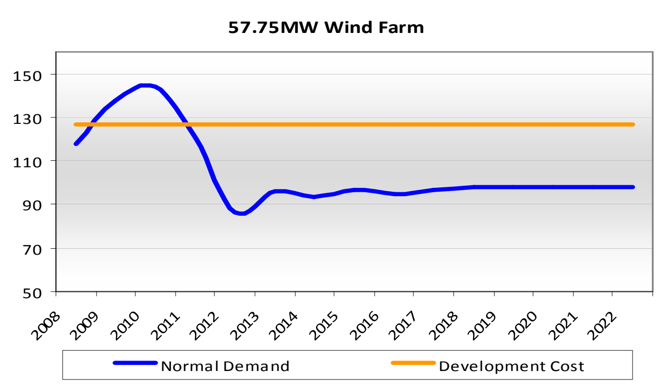

Figure 4-7: Normal Demand System Prices vs. Development Cost

Table 4-2 shows the difference between the system marginal cost and the wind development cost for wind farms connected to Calama 110. The actual difference shown in the table is the net present value of every difference. Is clear that, for investment under a normal demand, is necessary additional revenues other than the payment received by selling the energy to the system at the system marginal price.

Table 4-2: Difference between System Marginal Cost and Development Cost

	57.75		90.75		173.25	
	Normal Demand	High Demand	Normal Demand	High Demand	Normal Demand	High Demand
2008	-$ 9.20	-$ 9.20	-$ 9.99	-$ 9.99	-$ 11.62	-$ 11.62
2009	$ 10.61	$ 10.61	$ 11.27	$ 11.27	$ 8.41	$ 8.41
2010	$ 17.00	$ 30.77	$ 16.30	$ 30.39	$ 14.84	$ 26.37
2011	-$ 6.24	$ 41.53	-$ 6.72	$ 40.11	-$ 8.69	$ 32.03
2012	-$ 40.40	-$ 11.38	-$ 38.81	-$ 11.63	-$ 39.49	-$ 12.01
2013	-$ 30.95	$ 53.95	-$ 29.90	$ 52.12	-$ 32.78	$ 41.57
2014	-$ 33.26	$ 121.81	-$ 32.08	$ 118.55	-$ 31.13	$ 101.65
2015	-$ 30.38	$ 157.53	-$ 28.70	$ 154.57	-$ 27.96	$ 148.16
2016	-$ 32.14	$ 154.54	-$ 30.82	$ 149.71	-$ 30.47	$ 141.36
2017	-$ 30.26	$ 175.60	-$ 29.09	$ 175.45	-$ 28.07	$ 175.06
2018	-$ 28.83	$ 179.79	-$ 27.28	$ 181.06	-$ 26.20	$ 180.02
2019	-$ 28.83	$ 179.79	-$ 27.28	$ 181.06	-$ 26.20	$ 180.02
2020	-$ 28.83	$ 179.79	-$ 27.28	$ 181.06	-$ 26.20	$ 180.02
2021	-$ 28.83	$ 179.79	-$ 27.28	$ 181.06	-$ 26.20	$ 180.02
2022	-$ 28.83	$ 179.79	-$ 27.28	$ 181.06	-$ 26.20	$ 180.02
Actual Difference [US$/MWh]	-$132.31	$607.28	-$127.08	$601.36	-$132.48	$565.92

Among the possibilities to make a wind project economically viable under normal demand there is the arrangement of a bilateral contract, which would assure the income of the wind farm. The setting of a price for a contract is detailed on further sections. Is important to remember that the energy revenues perceived by the wing farm on a real system operation is not the direct product between the node marginal price and the generated energy; this because the wind farm also sells energy on other nodes which have different prices and this translates into differences between the direct product and the actual energy revenue.

To have a preliminary idea of the amount of additional revenues that the wind farm would have to face to become economically viable when selling its energy at marginal price the income will be calculated as the direct product between the generated energy and the marginal cost, remembering that is only a preliminary calculation and is not the way it is done in the SING. Table 4-3 shows net present value of the revenues needed by the wind farm to become economically viable using 10% of discount rate.

Table 4-3: Additional Revenues Needed (Preliminary)

	Normal Demand		
	57.75	90.75	173.25
Revenues Needed [US$]	-$ 22,728,718.07	-$ 34,305,001.07	-$ 68,271,107.90

For the case of an adapted system the system marginal costs are, as mentioned before, very low for the normal demand scenario. Therefore the development cost goes above the price evolution most of the time and the situation is worst than what was seen in the case with normal demand and non-adapted system (Figure 4-8).

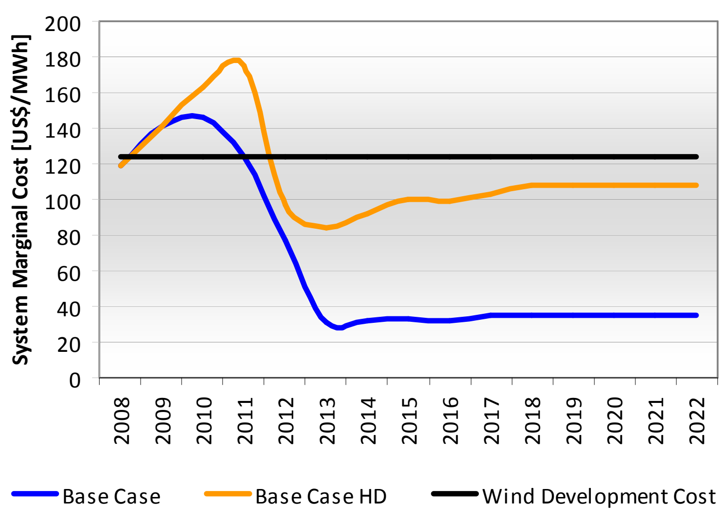

Figure 4-8: Normal Demand System Prices vs. Development Cost – Adapted System

4.2 Economic Evaluation

As specified earlier there were 18 cases modeled plus 2 base cases (Normal and High demand). For each one of the 18 cases, where wind energy was included into the electrical system, a NPV was obtained. Also, the results were sensibilized through:

- *The possibility of not receiving firm capacity payment.*
- *Two different prices for the emitted CERs* (Registered and Unregistered CDM project). In the primary market, CERs prices from registered projects are valued between US$16.2-19.7, depending on payment terms, while CERs from unregistered projects are quoted between US$11.2-16.2 (Point Carbon, 2007).
- *Three different discount rates* (10%, 11%, 12%).
- *Possibility of an energy purchase contract;* the calculation of the contract price assumed was explained on a previous section.

All these cases were evaluated due to the possibility of happening depending on the project development and the regulatory reality, which does not state clearly for example how a wind farm should be paid for its firm capacity. The assumptions made to economically evaluate the installation of the wind farm are:

- *Evaluation period:* 20 years
- *Turbine Model:* Vestas V.82 1.65MW
- *Capacity Factor:* given by the wind availability
- *Firm Capacity:* Calculated on a previous section
- *CERs price:* US$11.2 for unregistered and US$16.2 for registered project
- *Emission Displacement:* Calculated with developed technique explained earlier

- *Wind Farm Cost:* Obtained from Vestas South America (US$2500/kWh installed)
- *Fixed Operational Costs (US$/year):* 1% of annualized equipment and machinery investment.
- *Administration and Sales Costs (US$/year):* 1.5% of annualized equipment and machinery investment.
- *Linear Depreciation in 20 years*
- *Maintenance, Service and Supervision Costs:* Constant for every wind farm size.
- *Wind Availability:* Same wind availability for every year.

The results for each case will be presented through charts showing every case on normal demand scheme for each sensibilized variable with a non-adapted system; this means that there are 8 scenarios in which the NPV for each case on normal demand is presented. In this analysis only 5 scenarios will be analyzed and they are as follows:

Table 4-4: Analyzed Scenarios

	Firm Power	Energy Purchase Contract	Registered CDM Project
1st Scenario	NO	NO	NO
2nd Scenario	YES	NO	NO
3rd Scenario	NO	NO	YES
4th Scenario	YES	NO	YES
5th Scenario	YES/NO	YES	YES/NO

The high demand cases were excluded because always show positive NPV under any sensibilized variable; this occurs because the prices on a high demand scheme are too high, and thus the energy revenues become excessively high and any other revenue perceived is not large enough to actually affect the NPV of the project. For each graph the cases are as follows:

$$Normal\ Demand\ Cases = \begin{cases} 57.75MW & \begin{cases} Case\ 1 & : O'Higgins\ 220 \\ Case\ 2 & : Calama\ 110 \\ Case\ 3 & : Crucero\ 220 \end{cases} \\ 90.75MW & \begin{cases} Case\ 4 & : O'Higgins\ 220 \\ Case\ 5 & : Calama\ 110 \\ Case\ 6 & : Crucero\ 220 \end{cases} \\ 173.25MW & \begin{cases} Case\ 7 & : O'Higgins\ 220 \\ Case\ 8 & : Calama\ 110 \\ Case\ 9 & : Crucero\ 220 \end{cases} \end{cases}$$

Furthermore, an additional scenario will be analyzed considering the case where a coal adapted system expansion plan is simulated. For this case, only the best case scenario will be shown.

4.2.1.1 1st Scenario: No Firm Capacity Payment, No Energy Purchase Contract and Unregistered CDM Project

This is the worst case scenario that the wind farm could face. In this scenario there is not additional revenues perceived from firm capacity payment and the revenues perceived by the emission displacement is with low CER prices.

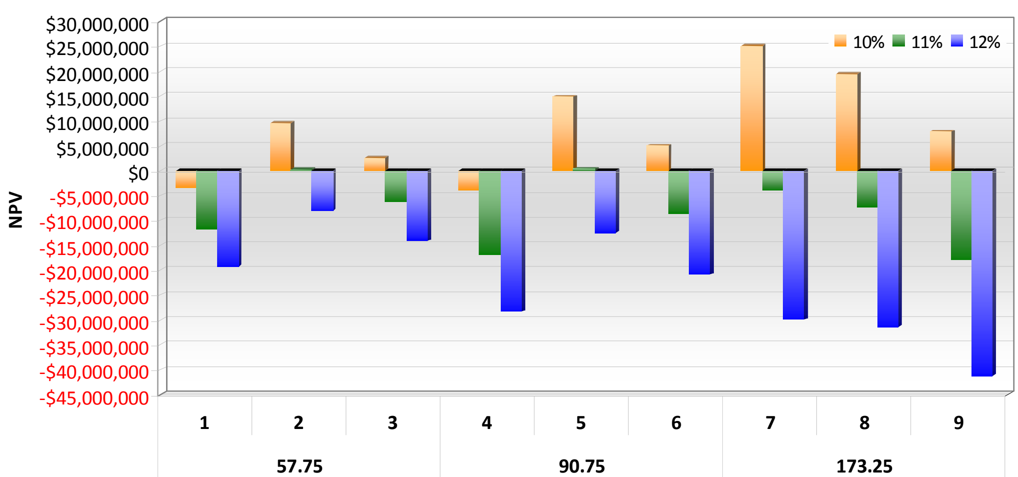

Figure 4-9: NPV for 1st Scenario

On Figure 4-9 is possible to observe that for a simulation case with 10% of discount rate, the most profitable situation is installing a 173.25MW wind farm connected to O'Higgins 220 and the second is with the same wind farm size but connecting it to Calama 110. In this scenario is not possible to request high returns from the project. In case of requesting 12% of return all the possibilities become unprofitable and this would lead to deciding not to invest.

Figure 4-10 shows the internal rate of return (IRR) for each evaluated case. Is possible to see that the IRR is very low and does not allow having a return higher than 11%, which is represented by the negative NPV on Figure 4-9 for the case of 12% discount rate.

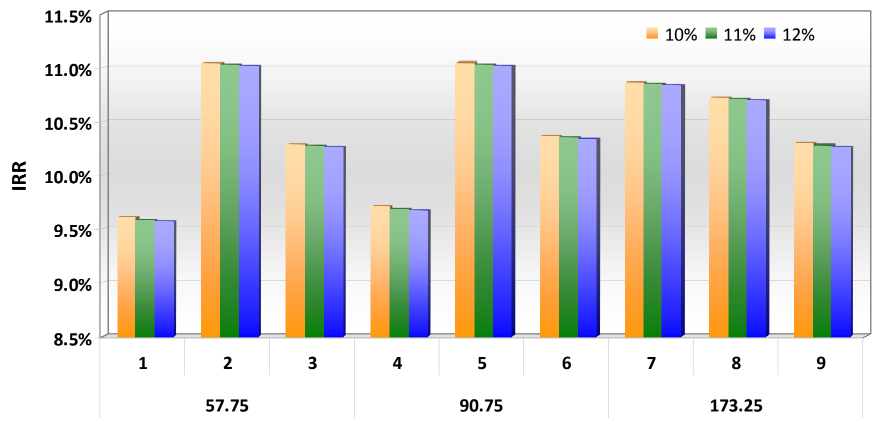

Figure 4-10: Internal Rate of Return for 1st Scenario

4.2.1.2 2nd Scenario: Firm Capacity Payment, No Energy Purchase Contract and Unregistered CDM Project

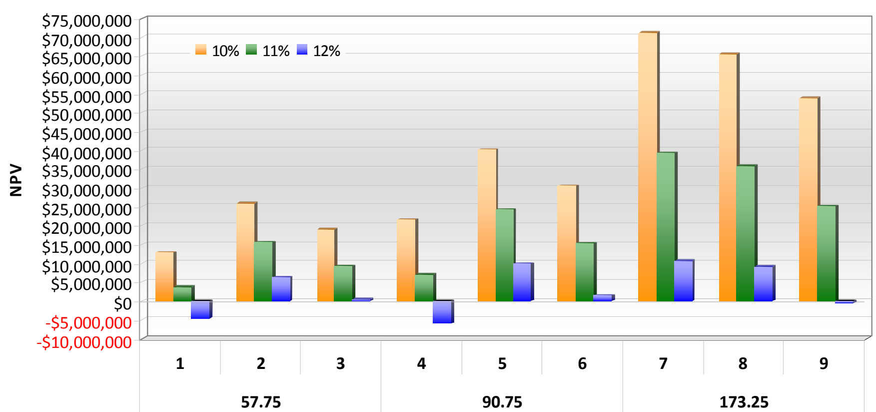

Figure 4-11: NPV for 2nd Scenario

Figure 4-11 shows that the situation improves in relation to the first scenario. The project becomes more profitable and is possible to demand a greater return in most cases. The connection on O'Higgins 220 is the less profitable for 57.75MW and 90.75MW wind farms. Once again the most profitable investment is the 173.25MW wind farm connected to O'Higgins 220.

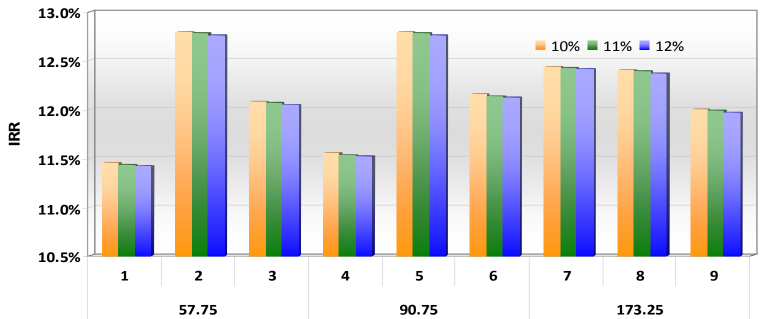

Figure 4-12: Internal Rate of Return for 2nd Scenario

The IRR improves considerably in relation to the 1st scenario, in this case is possible to request a higher return from the project in most of the cases as mentioned before.

4.2.1.3 3rd Scenario: No Firm Capacity Payment, No Energy Purchase Contract, Registered CDM Project

In this case the project perceives higher incomes from selling CERs; this happens because the on CERs market the prices for registered projects are set higher.

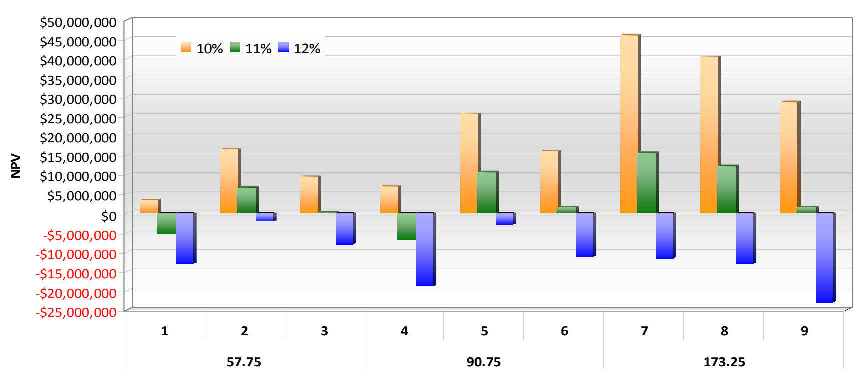

Figure 4-13: NPV for 3rd Scenario

Figure 4-13 shows that for a registered CDM project, the project becomes more profitable than the first scenario but still needs the firm capacity payment to be able to demand a higher return. In this scenario, as well as the first one, the project shows negative NPV for a discount rate of 12%.

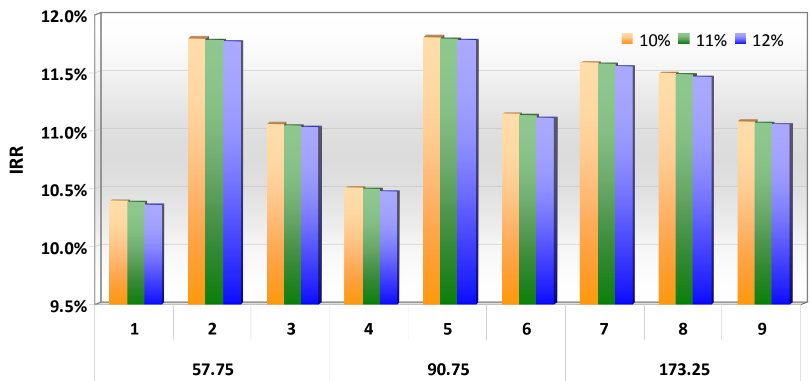

Figure 4-14: Internal Rate of Return for 3rd Scenario

4.2.1.4 4th Scenario: Firm Capacity Payment, No Energy Purchase Contract, Registered CDM Project

This scenario is the best case scenario. In this scenario all additional revenues are considered and due to the system price, the project has very good returns.

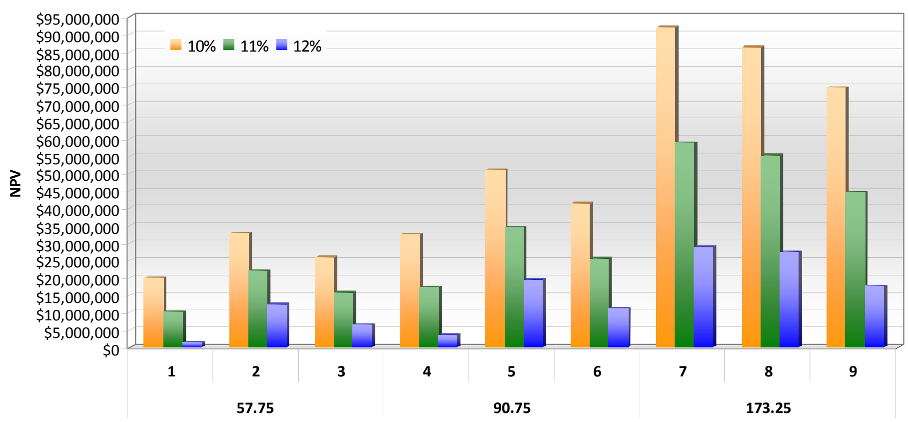

Figure 4-15: NPV for 4th Scenario

Figure 4-15 shows, how the project becomes more profitable with additional revenues, in this case is possible to demand higher returns from the project no matter the sizes or the connection node of the wind farm; this means that the project, for all discount rates, has positive NPV.

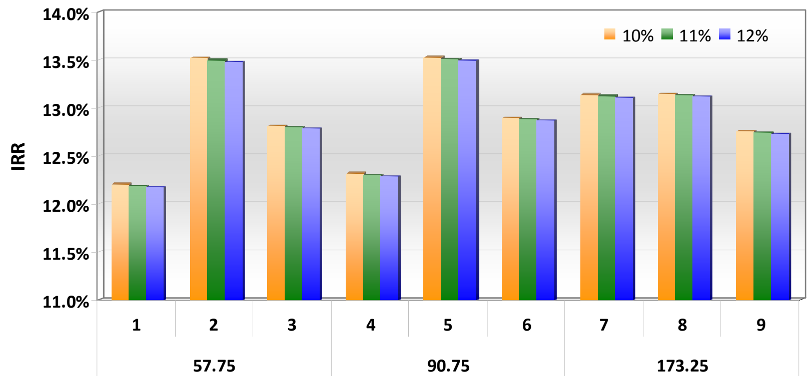

Figure 4-16: Internal Rate of Return for 4th Scenario

Figure 4-16 shows the profitability of the project. The graph shows that all the IRR are greater than 12%, which reaffirms the NPV data shown before, where for every discount rate it was positive. In this scenario, for some cases, is possible to demand returns above 12% and the project would still have positive NPV.

4.2.1.5 5th Scenario: Energy Purchase Contract

This scenario puts together the last four possible combinations of sensibilized variables. It is done because the variation in the NPV between the last four combinations is not very high. This happens given that the purchase contract price varies depending on the costs and the revenues perceived, as explained earlier, therefore when there are additional revenues the contract price is set lower than when the farm is not facing any other income apart from the energy revenues.

Furthermore, there is a special situation on this scenario, when there is no firm capacity revenue the wind farm has to establish a higher price for the generated energy, which at the end of the evaluation, translates into higher net present value for the project and thus higher internal rates of return.

Another characteristic of the energy purchase contract is that no matter the connection node, the wind farm always gets the same revenues for the generated energy, because the contract price is a function of the costs and incomes, and does not consider the system behavior, like node decoupling. Consequently, due to the similarity of the last situations, only one situation will be shown to express the behavior of the energy contract consideration.

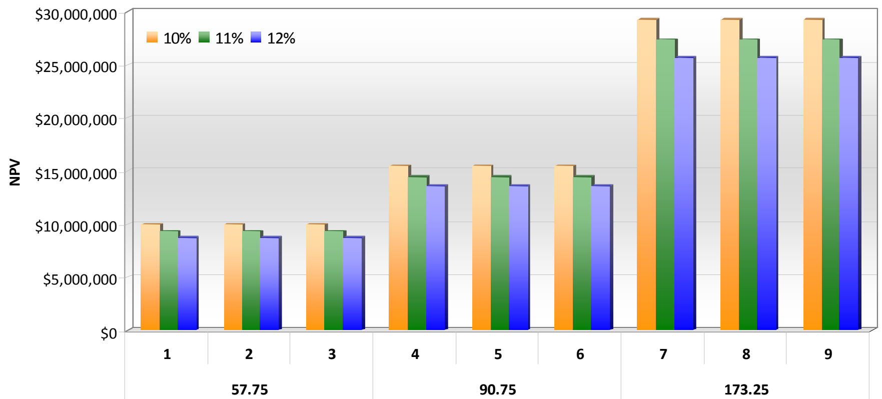

Figure 4-17: NPV for Energy Purchase Contract – No Firm Capacity and Unregistered CDM

In Figure 4-17 is possible to see how invariant is the NPV is among the same wind farm size, as explained before. Figure 4-18 shows that the IRR barely varies in function of the wind farm sizes, which happens due to the same reason mentioned above, the wind farm gets paid in function of its cost and additional revenues regardless of the system characteristics, therefore the wind farm size does not affect the connection node and neither the energy revenues received.

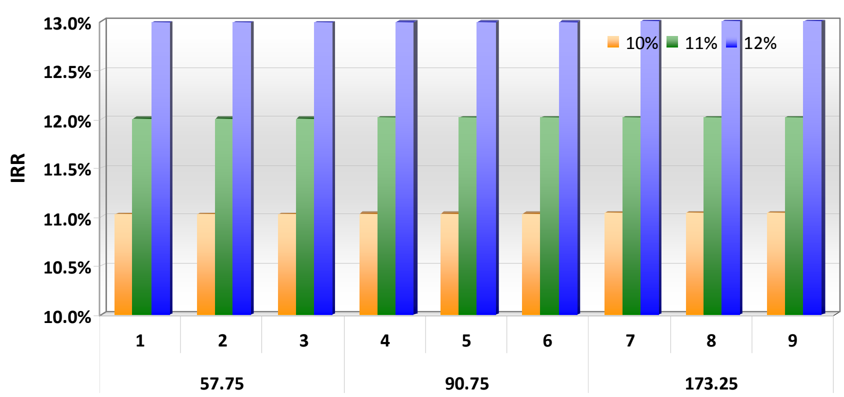

Figure 4-18: IRR for Energy Purchase Contract – No Firm Capacity and Unregistered CDM

4.2.1.6 Scenario under a Coal Adapted System

For a coal adapted system the system price is very low and all the possible simulation cases result on negative NPV, due to this, the only case analyzed here will be the best case scenario, which puts the wind project under firm capacity payment and assumes that the project is registered as a CDM project under the Kyoto Protocol. On this scenario the NPV is also negative but not as negative as the other cases.

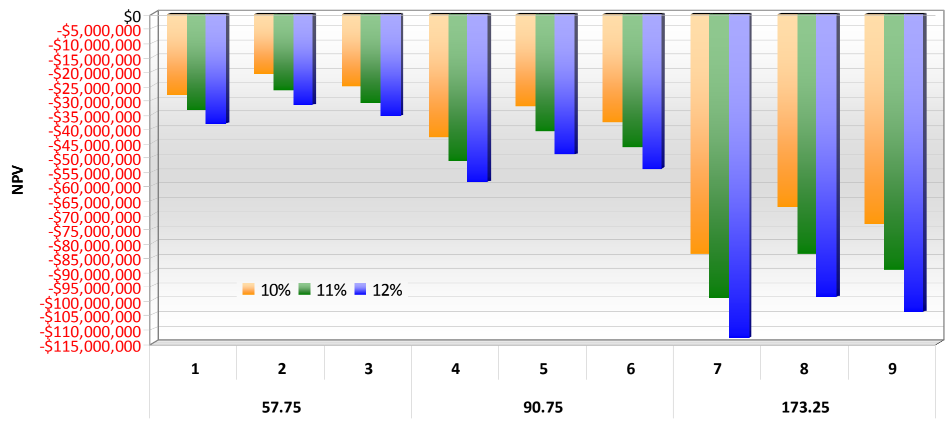

Figure 4-19: Coal Adapted System Situation

Clearly, from the negative NPV shown on Figure 4-19, the IRR is expected to be smaller than 10%. Figure 4-20 shows the values if IRR obtained for each case, the values, as expected, are smaller than 10% and hence, the NPV is negative for al simulated cases.

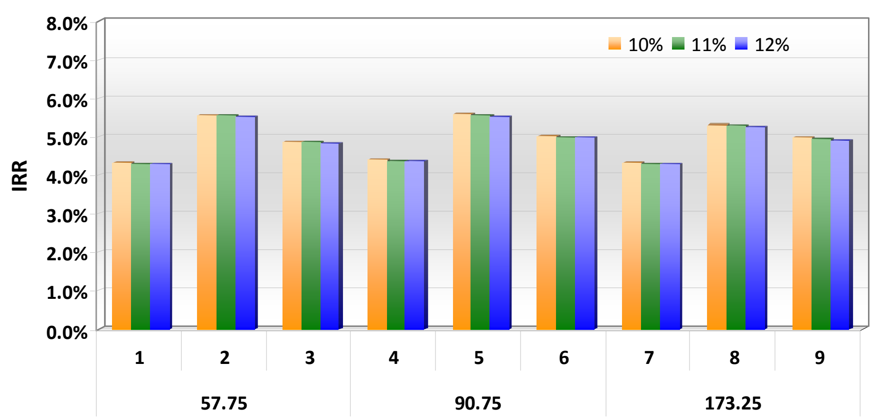

Figure 4-20: IRR on a Coal Adapted System

4.3 Marginal Income Analysis

Considering the cash flows obtained in the simulation of the wind farm inclusion is possible to calculate the Marginal Incomes, which, in this case, are calculated by dividing the annual cash flow (US$-year) by the amount of energy generated on that year (MWh-year); from that, the Marginal Income is represented by US$/MWh per year. With these values is possible to obtain the Net Present Value, which will represent the NPV per generated MWh, this term is named here as Marginal NPV. The following equation shows how to obtain the Marginal NPV mathematically.

$$NPV_{marginal} = -\frac{I}{\overline{E}} + \sum_{i=1}^{n} \frac{NI_i / E_i}{(1+r)^i} \tag{4.2}$$

$$\begin{aligned}
&where, \\
&NPV_{marginal} &&= \text{Marginal Net Present Value} \\
&E_i &&= \text{Energy Generated on Year 'i'} \\
&\overline{E} &&= \text{Average Energy} \\
&n &&= \text{Years of Evaluation}
\end{aligned}$$

Using equation (4.2) is possible to calculate the Marginal NPV for each simulated case. From the results obtained from the equation was possible to observe the same behavior for all cases except in one. These two behaviors will now be analyzed.

4.3.1 Marginal NPV Behavior

4.3.1.1 Decremental Marginal NPV

The results show the presence of a decremental marginal NPV. This means that when the wind farm installed is bigger has less income per generated MWh. The main reason for this to happen is, basically, the electrical system characteristics. There are two main situations that could happen: on one hand, there is the energy flow direction (Figure 4-21) to the connection node, where is assumed that the load is in the connection node and receives energy from the surrounding nodes, when the wind generation increases the load gets satisfied, on a higher amount, by the wind farm and thus reduces the flow of energy from the other nodes, this translates into lower and lower prices approaching the wind generation cost, which is zero, therefore lower income for the wind farm at higher generations.

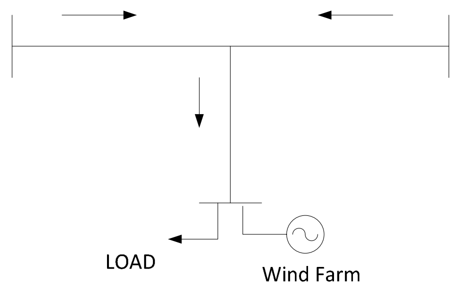

Figure 4-21: Load Direction Situation

On the other hand is the amount of generated energy; in some cases the wind farm can not inject all the possible generable energy into the system and this causes the generator to perceive less income.

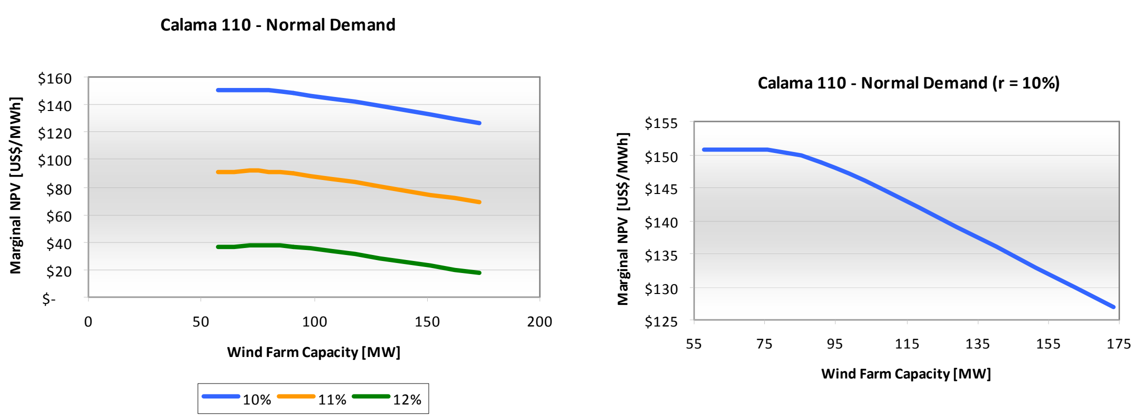

Figure 4-22: Decremental Marginal NPV Situation without Contract

When the wind farm signs a contract with a customer, establishing a determined price for the generated energy; one of the risks is no being predict the behavior of the system prices and this could translate into a reduction of the project profits. On the simulation, due to the system price evolution, happened the contrary; this means the installation of a wind farm becomes more profitable with the existence of an energy purchase contract. Is important to know that the contract price simulated is the lowest price at which the wind farm could sell its electricity due to investment payback and annual additional incomes (Firm Capacity and CERs).

On Figure 4-22 and Figure 4-23 is possible to see the decremental trend of the marginal NPV for the case of a farm connected to Calama 110 in the SING. On each graph there are three lines showing the different discounts rates considered in the simulation. Figure 4-23 shows higher marginal NPV; this is due to the contract price, which generates higher incomes than the marginal prices obtained in the simulation. The positive aspect of signing a contract is that is much easier to expect a higher return from the project because assures certain price in the energy generated and this avoids the variability of the system price, which sometimes could benefit but others damage the profitability of the project. On the simulation the results show that the marginal NPV is higher in the case with a purchase contract. Also with a contract there is less variability between the different discount rates.

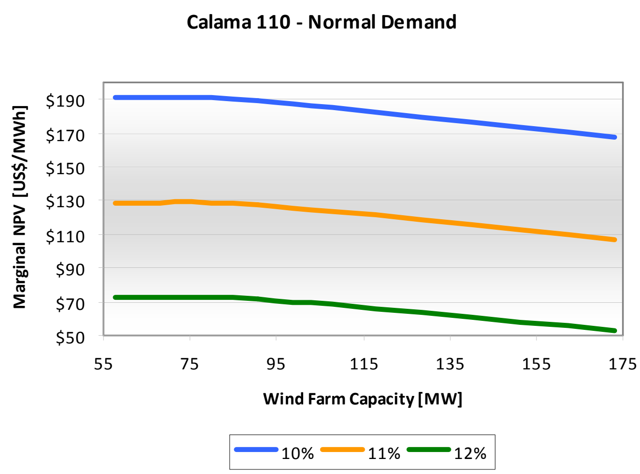

Figure 4-23: Decremental Marginal NPV Situation with Contract

4.3.1.2 Decoupled Connection Node

The situation where the connection node gets decoupled, happens when the line is at its capacity limit; in this situation is assumed that the wind farm is supplying energy to loads located away from the connection node as well as possible local loads, this means that the electricity flow goes away from the wind energy generation, so when there is a large wind farm, its generation easily tends to start filling the surrounding line capacities, this translates into lower price every time the generation increases because the node tends to assume the wind generation cost, but the problem appears when the system gets decoupled.

When this happens, the generator sells energy at more than one price. On one hand there is the price that stays in the connection node which is a low price as seen in the Decremental Marginal NPV situation and on the other hand is the price of the decoupled nodes, where energy is sold at higher prices and the wind farm sells part of its energy on these nodes (all the injected energy before decoupling).

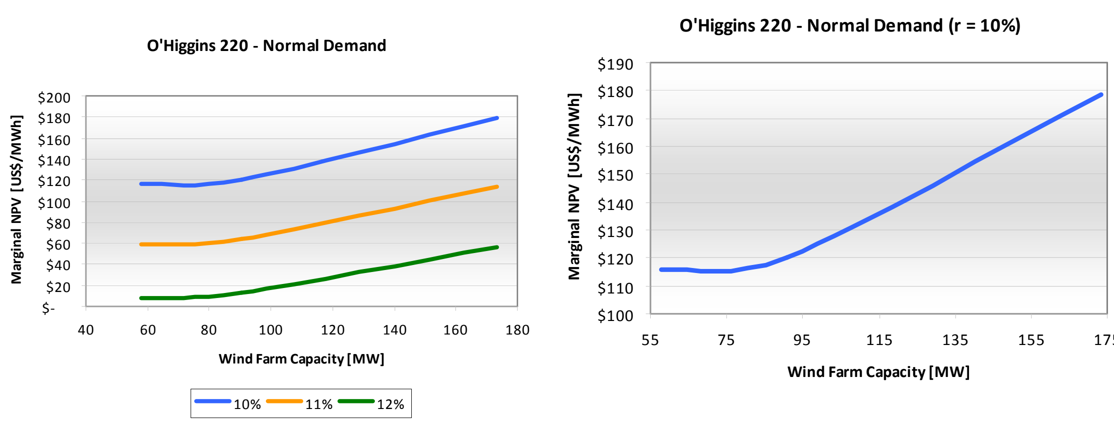

Figure 4-24: Decoupled System Situation

Figure 4-24 shows the situation for the simulation ran in the SING. Is possible to see that up to about 75MW of wind capacity, the connection node does not decouples, from that point the surrounding lines star decoupling and the wind generator starts perceiving higher incomes per MWh.

4.3.2 System Marginal Price vs. Annual Marginal Income

Considering the annual marginal incomes calculated to obtain the marginal NPV is possible to analyze these values by comparing them with the system marginal costs obtained in the simulation of the electrical system. Through this, an investment incentive or disincentive is shown by taking into account that the annual marginal incomes should be higher than the system marginal cost under a situation where the additional revenues and the cost make the wind farm profitable; in a case where the annual marginal incomes are lower than the marginal price the project will show a negative NPV and this symbolizes a unprofitable project and does not encourages the investment on wind technology in the SING.

Therefore, this comparison is useful to get a preliminary view about effective additional incomes that encourage the investment on a renewable energy project. In the case of the wind farm considered in the system simulation, there are two additional revenues perceived by the generating plant; one is the firm capacity revenue and the other is the revenue perceived due to CERs sales.

4.3.2.1 Firm Capacity Payment

To distinguish how feasible the installation of a wind farm in the SING is, two situations will be presented. In one hand there is the situation of assuming that the wind farm will receive firm capacity payment and on the other hand considering the situation where the wind farm do not qualify to be paid for firm capacity. With this is also possible to see how much the firm capacity contributes into the feasibility of the project.

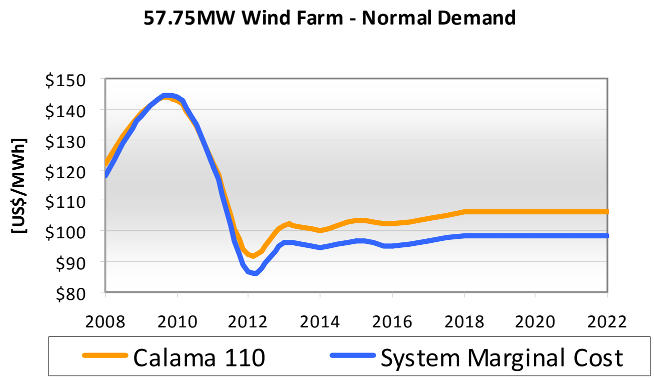

Figure 4-25: Marginal Price vs. Marginal Income (Calama 110) with Firm Capacity Payment

Figure 4-25 shows that the marginal income is equal or greater than the system marginal price most of the time, therefore a wind project with similar behavior to the one simulated should be economically feasible. For the simulation shown by the figure was considered a low CER price assuming that the wind farm is an unregistered CDM project. In case of registering the project the CER prices are higher and the farm shows higher probability of being profitable.

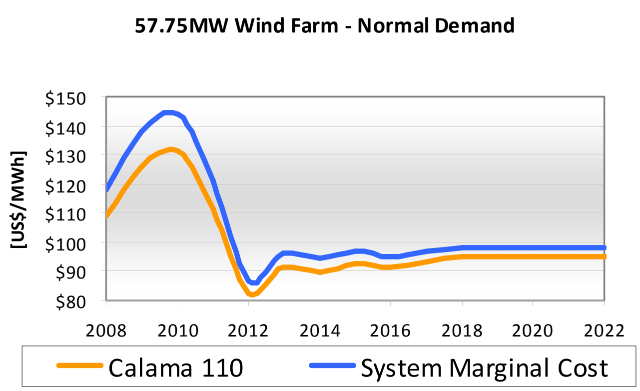

Figure 4-26: Marginal Price vs. Marginal Income (Calama 110) without Firm Capacity Payment

Figure 4-26 shows the opposite situation than what on Figure 4-25, in this case the marginal income goes below the system marginal cost, from this is possible to intuit that the wind farm under this situation will not be able to financially survive. The inexistence of firm capacity payment, in general for any renewable project, causes the reduction of annual incomes which can be a deciding factor when it comes to invest on renewable energy capacity.

4.3.2.2 CDM Registered Project

Depending on the characteristics of each project, the firm capacity payment might not be necessary. This happens when the income produced by the generation of CERs helps to avoid the losses caused by the lack of firm capacity payment. To achieve higher earnings is necessary to consider the wind farm or renewable energy project as a registered CDM project. On the CERs market, there are to sets of prices, one is the prices set for the unregistered projects, which are much lower that the set of prices at which the CERs for registered projects are traded. In the primary market, CERs prices from registered projects are valued between US$16.2-US$19.7, depending on payment terms, while CERs from unregistered projects are quoted between US$11.2-US$16.2 (Point Carbon, 2007). Therefore, if the renewable energy project is considered to be CDM registered project is considered to sell its CERs at US$16.2.

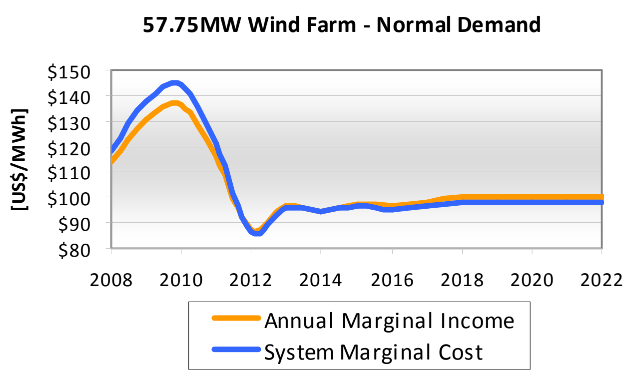

Figure 4-27: Simulation with Registered Project and without Firm Capacity payment

Figure 4-27 shows how the marginal income tends to increase as the CERs price go up. In the simulation was possible to see that with this CER price the NPV is positive and makes the wind farm profitable, probably not as much as with firm capacity payment but still an important contribution.

4.4 Law Incentives Analysis

On the second semester of 2007 the Chilean government has approved modifications to the electricity law regarding the better handling of non-conventional renewable energy (NCRE) inclusion into the two largest interconnected systems in Chile (SIC and SING). The main objective of these modifications, as stated by the government, is to create the right environments to materialize non-conventional renewable energy projects and hence, be able to generate trust among the market participants in relation to the development of these technologies in the long term.

The law modifications instate that the 5% of the injected energy by generating companies has to be accomplished by new NCRE technologies, this energy could be used by retailers or free clients. Therefore, the electricity companies should annually certify that the 5% of the total commercialized energy has been injected by NCRE sources. These sources could be owned by these companies or bought to a third party.

In Chile, technologies considered to be non-conventional are:

- Small Hydro plants (less than 20MW)
- Biomass and Biogas
- Geothermal
- Solar Energy
- Wind Power
- Wave Energy

To help accomplish the amount of NCRE generation, the government has established a penalty, which is 0.4 UTM per each unsupplied MWh of NCRE generation (1UTM=US$68).

4.4.1 Incentives to Generating Companies

Basically, the main problem of the modifications to the electricity law is that generating electricity using NCRE in the worst case scenario (negative NPV for the project) could be less profitable than paying the penalty the law establishes. This could make the companies to keep investing on cheaper technologies and pay the penalty every year. From the system simulations the worst case scenarios will be obtained and then will be compared with the amount of money the company should pay in case of not generating with NCRE, which in this case is wind power.

Difference

With Firm Power Payment and Non Registered CDM Project

		|NPV| - Penalty
	CASE\WACC	12%
57.75	O'Higgins 220	-$30,222,466.84
90.75	O'Higgins 220	-$48,858,174.40
173.25	Crucero 220	-$103,990,560.90

Without Firm Power Payment and Non Registered CDM Project

		|NPV| - Penalty		
	CASE\WACC	10%	11%	12%
57.75	O'Higgins 220	-$36,323,399.37	-$25,505,117.71	-$15,771,818.89
	Calama 110			-$26,844,458.23
	Crucero 220		-$31,056,802.31	-$20,863,486.65
90.75	O'Higgins 220	-$58,544,053.24	-$41,633,937.99	-$26,421,655.62
	Calama 110			-$42,367,707.81
	Crucero 220		-$49,925,361.37	-$33,995,143.26
173.25	O'Higgins 220		-$107,665,889.56	-$74,807,132.95
	Calama 110		-$104,356,062.36	-$73,386,736.54
	Crucero 220		-$93,669,958.18	-$63,542,242.80

Without Firm Power Payment and Registered CDM Project

		|NPV| - Penalty	
	CASE\WACC	11%	12%
57.75	O'Higgins 220	-$32,003,525.16	-$21,867,196.02
	Calama 110		-$32,939,835.36
	Crucero 220		-$26,958,863.78
90.75	O'Higgins 220	-$51,853,362.16	-$36,007,272.53
	Calama 110		-$51,953,324.73
	Crucero 220		-$43,580,760.18
173.25	O'Higgins 220		-$93,145,882.37
	Calama 110		-$91,725,485.97
	Crucero 220		-$81,880,992.23

Figure 4-28: Difference between NPV and Law Penalty – Non-Adapted System

Therefore, to see if the penalty applied is effective, the condition shown on equation (4.3) has to be true, taking into account that the values considered as wind farm NPV are negative.

$$\left|NPV_{wind}\right| \geq \left|NPV_{penalty}\left(p\right)\right| \tag{4.3}$$

$where,$

$NPV_{wind} \quad = Net\ Present\ Value\ of\ the\ Wind\ Project$

$NPV_{penalty}\left(p\right) \quad = Net\ Present\ Value\ of\ the\ penalty\ (function\ of\ p)$

$p \quad = penalty\ \left[US\$\right]$

From equation (4.3) is possible to calculate p for which the investment is less profitable than paying the penalty for the same period that the project is supposed to work for.

Figure 4-28 shows the difference between the negative NPV obtained from the system simulation with a non-adapted expansion plan, and the law penalty assuming that the wind farm does not get installed. Is possible to see that all the values in the figure are negative, which indicates that a penalty of 0.4UTM (US$27.2 @ 1UTM=US$68) is giving incentives to introduce wind energy in the SING.

When the wind farm does not receive firm capacity payment and is not registered as a CDM project there is a case where reaches the critical point first; this case is 57.75MW connected to O'Higgins 220 (12% discount rate). For this case the penalty price, where is better to assume the cost of the penalty, is US$14.91, which is much lower than the penalty established by law.

Although, the law is not as radical as it should be because it does not create enough incentives to invest on wind energy and diversify the energy matrix, is possible to state that according to the simulation with a non-adapted system, the law gives investment incentives in the SING through its penalty when facing prices with a non-adapted system. Nevertheless, is important to point out that is possible that for smaller projects of large generation companies, the penalty payment would become suitable.

When analyzing the simulation where the system is coal adapted, the reality is different. Prices are very low and this makes every project under normal demand and some under high demand unprofitable. The law applicability depends on the magnitude of the negative NPV as shown on equation (4.3). For the case of wind energy in the SING the NPV are extremely negative under normal demand scenario; this causes the penalty to be preferred over developing the project.

Table 4-5: Difference between NPV and Law Penalty – Coal Adapted System (No Firm Capacity, Unregistered Project)

		10%	11%	12%
57.75	1	$4,840,972.90	$11,770,922.31	$18,060,235.50
	2	-$2,618,904.78	$4,785,976.00	$11,501,671.24
	3	$1,826,740.25	$8,985,753.52	$15,479,247.24
90.75	4	$6,029,712.49	$16,859,097.32	$26,685,481.17
	5	-$4,793,332.44	$6,743,808.60	$17,204,987.36
	6	$777,068.16	$12,006,617.16	$22,190,151.29
173.25	7	$12,242,589.85	$32,723,299.92	$51,300,817.43
	8	-$4,308,304.38	$17,316,250.46	$36,917,214.95
	9	$1,750,421.20	$22,988,901.39	$42,243,998.20
57.75	10	Develop	Develop	Develop
	11	Develop	Develop	Develop
	12	Develop	Develop	-$28,655,073.62
90.75	13	Develop	-$50,480,942.07	-$34,794,010.19
	14	Develop	Develop	Develop
	15	Develop	Develop	-$46,165,824.01
173.25	16	Develop	-$91,291,622.78	-$61,763,631.60
	17	Develop	Develop	-$96,815,421.99
	18	Develop	Develop	-$82,874,855.15

On Table 4-5 negative values indicate that the investor decides to develop the project instead of paying the penalty and positive values indicates that the penalty is a better choice. In the cases where it says ‘Develop’ means that the project has a positive NPV and clearly is preferred over paying the penalty. Table 4-5 shows the worst case scenario that a wind project could face.

From the obtained results is possible to say that the penalty of 0.4UTM is not big enough to foster the investment on wind energy. The idea is for all the values on Table 4-5 to be negative, in this point the penalty is high enough and fosters the investment. It is possible to calculate the optimum penalty value that triggers all investors to prefer developing the wind project. This value can be calculated through the following equation and applying it to the last value that becomes negative.

$$P)\,Min_{\{P_o\}}\left[\left|NPV_{wind}\right| - NPV_{penalty}\left(P_o\right)\right] \tag{4.4}$$

$$\begin{aligned} &\textit{suject to} \\ \left|NPV_{wind}\right| - NPV_{penalty} &\geq 0 \\ NPV_{wind} &\leq 0 \\ NPV_{penalty} &\geq 0 \\ P_{penalty} &\geq 0 \end{aligned}$$

$$\begin{aligned} &\textit{where,} \\ &P_o \quad = \textit{Optimal Penalty} \end{aligned}$$

From the results, the last value that becomes negative when increasing the penalty is the Case 1 with a discount rate of 12%. Applying equation (4.4) to this case the optimum penalty is US$41.28 dollars, which is 0.61UTM. When the penalty reaches this value is better to develop the project instead of paying the penalty for every simulated case.

4.4.2 Incentives to Large Mining Companies

On the SING the most important clients are the mining companies. These companies demand most of the electricity generated in the SING and therefore are candidates of being the buyers for the energy generated from wind energy source. Due to the importance of the energy supply, mining companies establish contracts where the price takes care of possible problems the generating company could face and that would diminish the probability of supplying electricity full time, taking into account the great loses carried by a non-supplied energy period.

To be able to analyze the incentives that mining companies have to buy wind energy, four contract cases will be examined (Table 4-6). The basic assumption is that the price that mining companies establish for their energy contracts are at marginal cost of the fuel providing electricity, this fuel will be assumed to be coal.

Table 4-6: Mining Company Energy Contract Cases

Mining Companies Contract Cases	
Case I	Buying only Coal Energy @ 35[US$/MWh]
Case II	Buying only Wind Energy @ Wind Contract Price
Case III	Buying Coal and Paying the Generating Company the Law Penalty
Case IV	Buying Coal and Paying the Generating Company a Compensation for not buying Wind Energy

For all cases shown on Table 4-6 is assumed that the mining company buys the amount of energy generated by the wind farms analyzed in the simulation supposing that these amounts would represent a quantity lower or equal to the 5% of its consumption. An explanation of each case is shown below:

- **Case I** is the base case for the energy purchase for the mining company, assuming that the law does not exists and the mining company only buys energy from coal-fired plants. For the contract in this case, the price is assumed to be 35 [US$/MWh].

- **Case II** is where the mining company buys all the energy generated by the wind farm at wind energy purchase contract price. In this case the mining company does not subsidy the wind generation as the wind farm is capable of surviving under contract prices, as observed in the simulation (positive NPV in all simulated cases).

- **Case III** shows the situation where the mining company buys the amount of energy that would be generated by wind from coal-fired plants and gives the generating company a compensation, which is equal to the amount of money that the generating company will have to pay for not generating with wind (not doing the wind project); this means that the mining company faces the following price:

$$Price\left[US\$/MWh\right] = P_{coal} + P_{penalty} \tag{4.5}$$

$$
\begin{aligned}
&where, \\
&P_{coal} \quad = \textit{Price for Coal-Fired Contract} \\
&P_{penalty} \quad = \textit{Price of Law Penalty (0.4UTM=US\$27.2)}
\end{aligned}
$$

- **Case IV** is the same situation as before but the generating company develops the project and sells its energy on the spot market. In this case the generating company has incentives to do the project just in situations where the NPV of the project is positive. In the situations where the NPV is negative, the generating company could ask the mining company to give a compensation for not buying wind energy. This compensation is the penalty level at which the generating company has incentives to start paying the penalty instead of installing a wind farm and therefore is the price at which the project this negative NPV becomes profitable (NPV=0). This price is calculated through the following optimization:

$$
P) Max_{\{P_C\}} \left[\left| NPV_{wind} \right| - NPV_{penalty} \left(P_C \right) \right] \tag{4.6}
$$

$$
\begin{aligned}
&\textit{suject to} \\
&NPV_{wind} \leq 0 \\
&NPV_{penalty} \geq 0 \\
&P_{penalty} \geq 0
\end{aligned}
$$

$$
\begin{aligned}
&where, \\
&P_c \quad = \textit{Compensation Price}
\end{aligned}
$$

The compensation price calculated is an additional revenue per MWh needed but after taxes, therefore the price the mining company would have pay is calculated as follows:

$$
Price\left[US\$/MWh\right] = P_{coal} + \frac{P_C}{\left(1 - 17\%\right)} \tag{4.7}
$$

4.4.2.1 Case I

Table 4-7 shows the total annual payment the mining company has to pay when contracting energy without the law obligation.

Table 4-7: Case I Energy Payments

	Energy [MWh]	Fuel Type	Additional Payment	Price [US$/MWh]	Total [US$]
Case I	171,779,000	Coal	NO	35	$ 6,012,265,000
	269,940,000	Coal	NO	35	$ 9,447,900,000
	515,334,000	Coal	NO	35	$ 18,036,690,000

4.4.2.2 Case II

In this case there are only three different results for each rate of return analyzed because when the generating company establishes energy purchase contract, both high and normal demand show the same NPV. Also, no matter the connection node the NPV is the same, therefore only varies with the wind farm sizes. The contract price tries to be set as low as possible; this means that the generating company is forced to use the lowest rate of return possible, which in the simulation is 10%; moreover to make sure to receive firm capacity payment and to be a registered CDM project.

Table 4-8 shows the annual payments done by the mining company when facing a wind energy purchase contract.

Table 4-8: Case II Energy Payments

	Energy [MWh]	Fuel Type	Additional Payment	Price [US$/MWh]	Total [US$]
Case II	171,779,000	Wind	NO	92.30	$ 15,854,890,520
	269,940,000	Wind	NO	92.30	$ 24,914,973,000
	515,334,000	Wind	NO	92.30	$ 47,564,394,665

4.4.2.3 Case III

Table 4-9 shows the total annual payment the mining company has to pay when contracting energy including the law obligation but under the situation where the generating company decides not to invest on wind energy because the mining company covers the penalty imposed by law.

Table 4-9: Case III Energy Payments

	Energy [MWh]	Fuel Type	Additional Payment	Price [US$/MWh]	Total [US$]
Case III	171,779,000	Coal	YES - Penalty	62.2	$ 10,684,653,800
	269,940,000	Coal	YES - Penalty	62.2	$ 16,790,268,000
	515,334,000	Coal	YES - Penalty	62.2	$ 32,053,774,800

4.4.2.4 Case IV

For this case the possible situations are all the simulation cases where the NPV resulted to negative (Figure 4-28). As mentioned before, is assumed the when the mining establishes a contract price where it is paying a compensation, tries to reach the lowest price possible and this happens when the generating company is made to expect 10% of returns from the wind project. For this discount rate the negative NPV cases are only two (57.75MW and 90.75MW wind farms without firm capacity payment and unregistered CDM project), for all the other cases the mining company does not need to give compensation as the generating company sell the wind energy on the spot market without losing money. Therefore the energy payments are:

Table 4-10: Case IV Energy Payments

	Energy [MWh]	Fuel Type	Additional Payment	Price [US$/MWh]	Total [US$]
Case IV	171,779,000	Coal	YES - Compensation	37.85	$ 6,501,248,060
	269,940,000	Coal	YES - Compensation	37.08	$ 10,009,111,414
	515,334,000	Coal	YES - Compensation	35.00	$ 18,036,690,000

4.4.2.5 Discussion

Comparing all cases with the base case (Case I) is possible to observe that, under law obligations, the case where the mining company decides to compensate the generating company (Case IV) is the case that would be used to establish the contract price. This means that the law sets a high enough penalty to foster the generation with renewable energy, but does not encourages the use of wind energy by the large mining clients, whom are the most important clients in the SING.

Clearly, compared to the prices this clients face, is completely uneconomical to buy wind energy instead of coal (Case II), furthermore is better to promote not investing in wind power and pay the penalty (Case III), which is totally opposed to what the law aims.

4.4.3 Law Applicability Conclusion

The law applicability depends strictly on the future of the system. The worst case scenario for the law is a coal adapted system; in this case the system price stabilizes on a very low price (coal marginal cost) and makes wind project to be highly unprofitable, this makes investors to choose paying the law penalty instead of installing a wind farm. This situation could be counteracted by increasing the amount of penalty imposed by law to a value greater than 0.61UTM.

When a wind project faces higher system prices, the gap between the penalty and the profitability of the project gets smaller. Under this reality the law seems to be affective and it would foster wind energy investment in the SING. Nevertheless, any additional investment on cheaper technologies would pull the system prices down causing motivations for investors not to invest on wind energy.

Therefore, the law in not fully effective and needs markets with high prices. The main solution to this problem is increasing the penalty to values greater than 0.61UTM. With this the law would be fostering wind energy investment in the SING no matter the price realities the market could be facing.

From large client’s point of view, the decision is the same for both situations (adapted and non-adapted system), because is assumed that large clients have the possibility of signing contracts at coal marginal cost. The large client will end up signing contracts at coal price and paying a compensation to the wind generators for the case of facing high system prices and deciding to pay the penalty in case of having a system adapted to coal. Therefore the law does not encourage buying wind energy, and in the case of having a coal adapted system encourages the large clients to pay the penalty as compensation.

4.5 Optimum Investment Decision

4.5.1 Maximizing NPV of the Project

Having enough resources to invest on wind farm, the decision is stated as an optimization problem over a planning horizon of T years, which in the case of a wind farm is 20 years. The optimization would intend to find the optimal wind farm size as well as the best connection node. The problem to solve is the following (Botterud & Korpas, 2004):

$$P)\, Max_{\{p,n\}}\left(-I_0+\sum_{k=1}^{T}\left[\left(1-r\right)^{-k}\times g_k\left(p,n,\Pi_{Capacity,k},\Pi_{CERs,k}\right)\right]\right) \tag{4.8}$$

subject to

$$p,n,\Pi_{Capacity,k},\Pi_{CERs,k}\geq 0$$

where,

$g_k\left(p,n,FP_k,ER_k\right)$	= *Annual Flow of year k*
p	= *Wind Farm Size*
n	= *Connection Node*
$\Pi_{Capacity,k}$	= *Firm Power Revenues on year k*
$\Pi_{CERs,k}$	= *CERs Revenues on year k*
r	= *Discount Rate*
T	= *Evaluation Period*
I_0	= *Initial Investment*

The only restriction of this problem is the non-negativity of the function arguments and does not consider budget restrictions. The annual flow g_k consists of the sum of energy revenues and additional revenues (Capacity and CERs) minus the costs (fixed and variable); this including the revenue tax (17%) applied every year and depreciation. Therefore the annual flow is defined as:

$$g_k\left(p,n,\Pi_{Capacity,k},\Pi_{CERs,k}\right)= \left[\Pi_{Energy,k}\left(p,n\right)+\Pi_{Capacity,k}\left(p,n\right)+\Pi_{CERs,k}\left(p\right)-C_k\right]\times\left(1-17\%\right)+17\%\times D_k \tag{4.9}$$

$$\begin{aligned}
&where,\\
&\Pi_{Energy,k}\left(p,n\right) && = Energy\ Revenues\ on\ year\ k\\
&\Pi_{Capacity,k}\left(p,n\right) && = Capacity\ Revenues\ on\ year\ k\\
&\Pi_{CERs,k}\left(p\right) && = CERs\ Revenues\ on\ year\ k\\
&C_k && = Total\ Costs\ of\ year\ k\\
&D_k && = Depreciation\ on\ year\ k
\end{aligned}$$

Is important to know that this maximization has to be done for each discount rate considered, depending on the returns expected from the project and also has to be done for each demand scenario, which are two in the simulation. Now, for the situation where the wind farm receives firm capacity payment and is considered to be unregistered CDM project, the optimal investment will be calculated.

4.5.1.1 Normal Demand Scenario

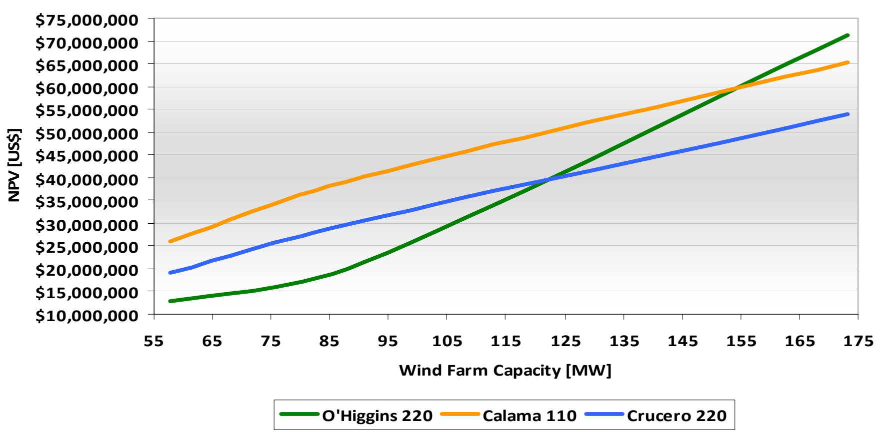

Figure 4-29: NPV Level Curves for 10% discount rate, Normal Demand

Figure 4-29 shows the level curves for the maximization objective function. From these curves is possible to see that the maximum NPV is obtained with a wind farm of 173.25MW connected to O’Higgins 220.

For the other two discount rates the solution is the same as it was in the case with 10%. On the case with 12% the values are much closer and the second highest value is for the case of a 90.75MW wind farm connected to Calama 110.

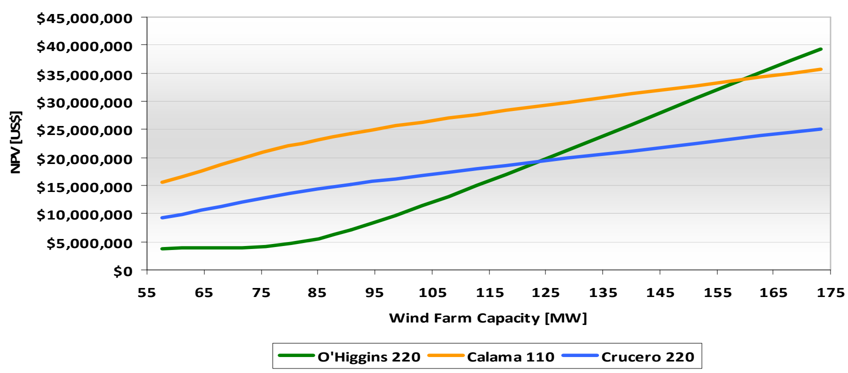

Figure 4-30: NPV Level Curves for 11% discount rate, Normal Demand

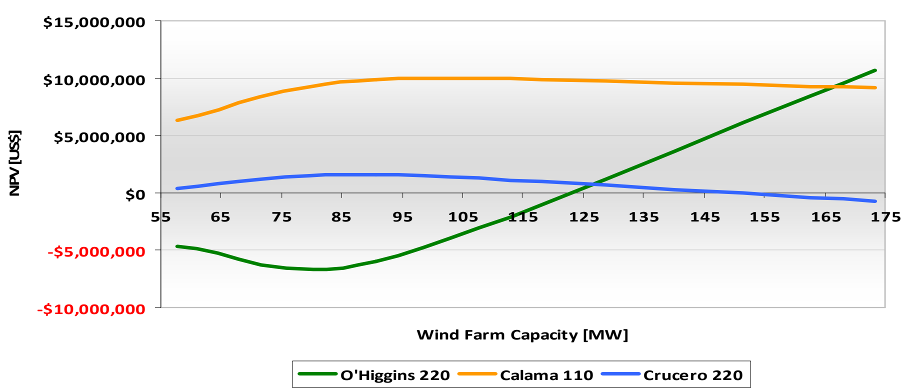

Figure 4-31: NPV Level Curves for 12% discount rate, Normal Demand

4.5.1.2 High Demand Scenario

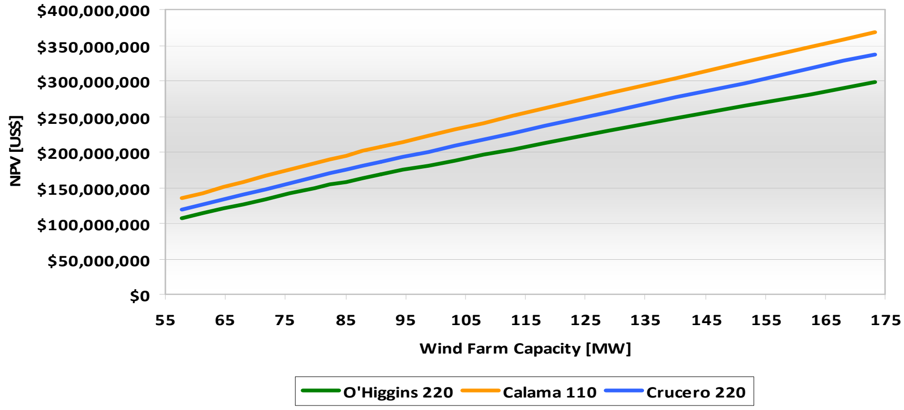

Figure 4-32: NPV Level Curves for 12% discount rate, High Demand

In the case of a high demand scenario the behavior of the curve is extremely similar and the optimum investment is always the same for every discount rate considered in the analysis. Therefore only one situation is shown by Figure 4-32. The optimum investment for the high demand case, for any of the three discount rates considered, is a 173.25MW wind farm connected to Calama 110.

4.5.2 Maximizing the Marginal NPV of the Project

Maximizing the marginal NPV is good when the investment is restricted; this means that investing more (larger wind farm) proves to be harder. When maximizing the marginal NPV, the wind farm size in not considered because the marginal incomes (US$/MWh) are used. Therefore, the decision is based on the investment that gives more revenues per MWh even though the final revenues could be lower. The maximization problem, using the same g_k as before, is:

$$P)\, Max_{\{p,n\}}\left(-\frac{I_0}{\overline{\overline{E}}}+\sum_{k=1}^{T}\left[\left(1-r\right)^{-k}\times\frac{g_k\left(p,n,\Pi_{Capacity,k},\Pi_{CERs,k}\right)}{E_k}\right]\right) \qquad (4.10)$$

$$\text{subject to}$$

$$p,n,\Pi_{Capacity,k},\Pi_{CERs,k} \geq 0$$
$$\overline{E},E_k > 0$$

where,

$g_k\left(p,n,FP_k,ER_k\right)$	$=$ *Annual Flow of year k*
p	$=$ *Wind Farm Size*
n	$=$ *Connection Node*
$\Pi_{Capacity,k}$	$=$ *Firm Power Revenues on year k*
$\Pi_{CERs,k}$	$=$ *CERs Revenues on year k*
r	$=$ *Discount Rate*
T	$=$ *Evaluation Period*
I_0	$=$ *Initial Investment*
E_k	$=$ *Generated Energy on year k*
$\overline{E}$	$=$ *Average Generated Energy*

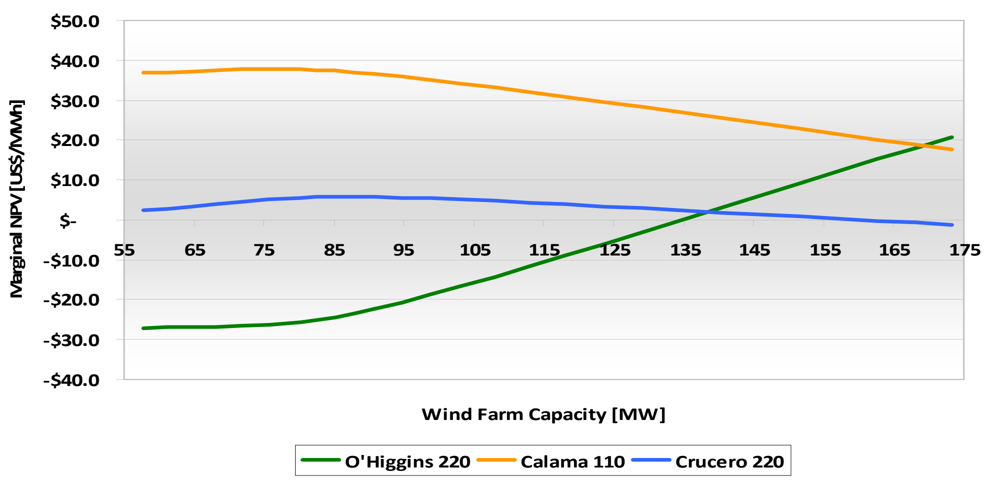

Figure 4-33: Marginal NPV Level Curves for 12% discount rate, Normal Demand

Figure 4-33 shows the case where the wind farm gets paid for capacity and is not a registered CDM project. Under these circumstances the optimum investment is the same for both, Normal and High Demand. The maximum is obtained when the investment is a 57.75MW wind farm connected to Calama 110.

Analyzing all the other possibilities, the results are the same; this means investing on a 57.75MW wind farm connected to Calama 110. There is only one situation where the result was different; the situation where the wind farm does not perceive capacity revenues (for both registered and unregistered as a CDM project) and requiring the project to have an 11% return under normal demand scheme. In this case the optimal investment is a 90.75MW wind farm connected to Calama 110, as seen on Figure 4-34.

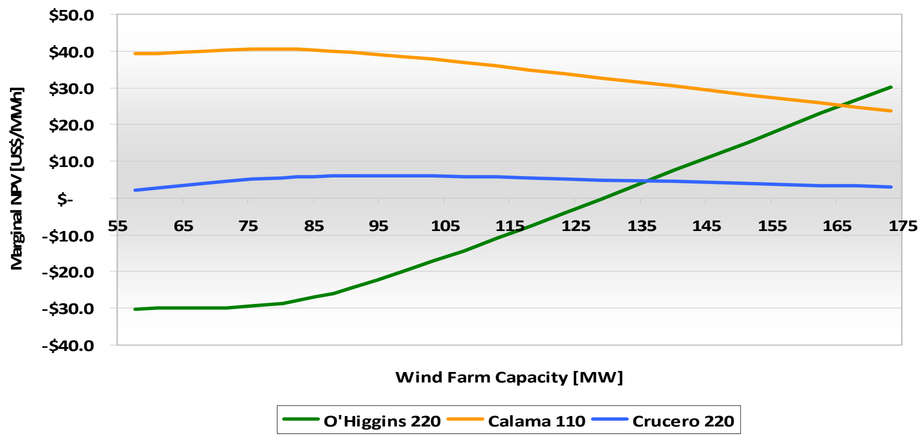

Figure 4-34: Marginal NPV Level Curves for 11% discount rate, Normal Demand

5 CONCLUSIONS AND FURTHER WORK

5.1 Conclusions

After all methodologies were applied, it is possible to conclude that the installation of wind farms is feasible under a market that faces prices high enough; this means systems where expensive technologies are generating (not adapted to lower cost technologies like coal). In this case, the law generates enough incentives to the installation of wind farms.

In the case of having a coal adapted system, which is a situation very likely to happen in the SING, the long term electricity price is much lower and this makes potential wind farm projects to be economically unfeasible. Moreover, on a market facing these prices, the law does not give adequate incentives for investing, this happens because the penalty imposed by law is not high enough and investors are induced to pay the penalty instead of investing on wind energy. Thus, the hypothesis formulated at the beginning of this thesis does not hold for this scenario.

Although wind power is not a new concept, the viability of selling the electricity produced from these turbines has improved in recent years due to technical advancements, as well as government mandates and incentives. Technical, commercial, and regulatory barriers restrain expansion of wind power in Chile. Wind-generated electricity is still expensive and technical problems need to be solved before wind can contribute more significantly to Chile’s power mix.

In Chile the market for wind power has developed very slowly, mainly due to a lack of a clear, consistent, streamlined framework for wind power, as well as incentives for wind developers. Barriers preventing a more robust market for wind power in Chile include:

1. *High Costs*: Chile, due to the lack of development on wind energy, does not have an easy way to import all the equipment required for a

wind energy plant to be installed. This makes the process very costly and translates into high development costs for the wind energy project.

2. *Limited Wind Resource Assessment Data*: Project developers need more information about wind resources in Chile in order to minimize risk and choose better sites. Chile should develop a detailed assessment of wind resources, and international assistance is likely needed to accelerate these activities.

3. *Lack of Regulatory Framework*: The actual regulatory framework does not give enough motivation to invest on renewable energy projects. The new obligations being considered would help to start investing on some projects but do not give the adequate signals to encourage investment.

5.2 Further Work

To analyze further work, it is important to summarize the contributions made by this thesis. This investigation starts from a private evaluation of an investment project done for a mining company. From this point, and with the objective of analyzing economical effects and real economical feasibility of wind energy inclusion on the electricity market, an economic dispatch model was constructed including wind energy generation and emission displacement.

Furthermore, the impact of capacity payments and emission reduction certificates on the evaluation of wind energy projects placed on the Chilean northern electricity market was analyzed.

Finally, due to the recent modifications being designed for the electricity law in relation to NCRE, a model to analyze the law applicability and investment incentive was developed.

Therefore, further work should be focused on model limitations and further research that could be achieved starting from the point this thesis left off. An important point is to model the inclusion of wind energy with greater detail. One significant limitation of the simulation model is not being able to handle a detail greater than weekly detail and therefore some intermittency on the wind resource might not be completely perceived. Hence, an interesting work would be analyzing the inclusion of wing energy into the system with greater detail (daily or hourly).

When including wind energy into any system there is more than just economical restraints. Thus, possible further work would be combining the work covered by this thesis with a technical analysis (reliability and dynamic effects analysis) for the system under investigation.

At last, for complementing the variables under analysis, it would be good to evaluate the impact of transmission line use and toll payment, applied to wind energy generation.

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Appendix A. WEIBULL DISTRIBUTION CALCULATION

It is very important to understand how your wind speeds are distributed, this means how much time the winds are strong (high wind speeds), and how much time they are weak (slow wind speeds). This is shown in a wind speed distribution. When the turbine expected power is calculated to get an average yearly generation is possible to take the curve of the wind speed distribution and multiply it with the power curve of the wind turbine. A very accurate statistical distribution used to represent wind speed is the Weibull distribution.

$$f(v) = \left(\frac{k}{\lambda}\right) \times \left(\frac{v}{\lambda}\right)^{k-1} \times e^{-(v/\lambda)^k} \tag{6.1}$$

On the equation above is possible to see the parameters that define the function, these parameters are k and λ, this function varies with the variation of the wind speed v. For adapting a Weibull distribution to the existing wind data from WP site, it is necessary to obtain the parameters of the density function. To obtain these parameters is essential to do the following.

$$\begin{aligned} k &= 1.05 \times \sqrt{\overline{V}}\,, \quad \textit{Low Variability} \\ k &= 0.94 \times \sqrt{\overline{V}}\,, \quad \textit{Medium Variability} \\ k &= 0.83 \times \sqrt{\overline{V}}\,, \quad \textit{High Variability} \end{aligned} \tag{6.2}$$

Where $\overline{V}$ is the wind speed average for the period under analysis. WP site can be considered as a medium variability due to the hourly wind behavior throughout the year. Now, to estimate the value of λ the formula below will be used.

$$\lambda = \frac{\overline{V}}{\Gamma(1/k)} \tag{6.3}$$

Therefore, for the WP site the following calculations where done:

$$k = 0.94 \times \sqrt{7.657} = 2.601$$
$$\lambda = \frac{7.657}{0.811} = 9.439 \left[{}^{m}\!/_{s} \right]$$

Subsequently, the Weibull density function is totally defined and with this is possible to plot the Weibull curve.

$$f(v) = 0.276 \times \left(\frac{v}{9.439} \right)^{1.601} \times e^{-(v/9.439)^{2.601}} \tag{6.4}$$

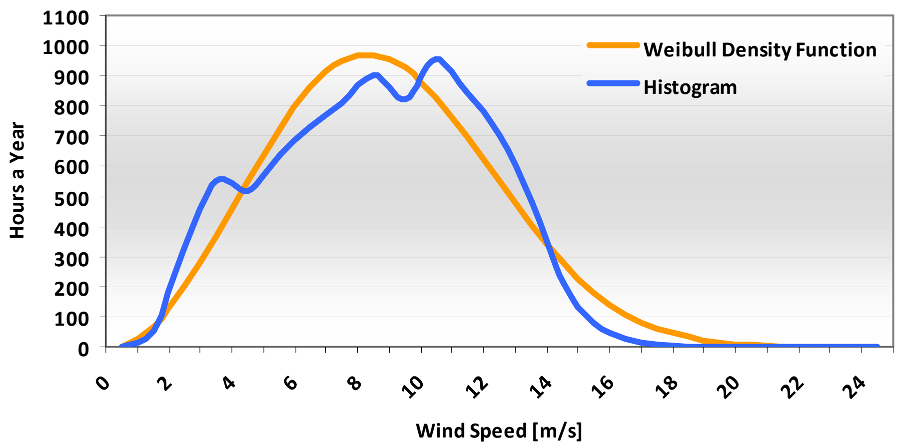

Figure 5-1: Weibull and Histogram for WP Site

Figure 5-1 shows the similarity between the histogram and the Weibull density function calculated. The curve adjustment is close enough and can be used as the distribution for the wind data in the WP site.

Appendix B. WP Site Wind Data

DAY\HOUR	1	2	3	4	5	6	7	8	9	10	11
1-Jan-04	6.54	4.34	1.86	2.14	3.12	4.46	4.1	3.91	3.77	5.2	4.92
2-Jan-04	2.07	2.21	3.39	6.9	7.16	6.83	8.64	8.81	8.29	7.83	6.78
3-Jan-04	1.02	2.36	4.87	6.49	6.35	7.78	8.57	8.79	10.03	8.89	7.64
4-Jan-04	3.29	5.2	5.76	7.07	7.83	6.21	7.5	8.36	7.33	7.55	6.88
5-Jan-04	2.65	1.4	3.91	5.44	7.64	8.6	7.98	9.12	6.95	5.08	2.62
6-Jan-04	4.6	5.18	5.16	8.26	9.15	7.14	5.73	7.74	4.03	2.6	2.81
7-Jan-04	5.83	2.29	0.54	1.26	3.82	5.63	5.13	4.32	3.1	4.53	5.11
8-Jan-04	5.32	3.39	0.83	2.57	3.67	5.42	6.57	5.2	4.53	3.44	2.17
9-Jan-04	6.85	5.06	2.79	1.78	3.31	4.96	5.06	4.22	4.75	4.05	3.7
10-Jan-04	4.49	1.81	0.35	1.14	0.64	2.17	4.49	4.89	5.66	5.66	3.44
11-Jan-04	4.82	5.32	4.49	1.62	1.33	0.78	1.09	2.48	6.02	7.02	5.11
12-Jan-04	3.15	1.93	3.34	5.06	7.07	7.14	6.59	6.73	7.71	10.35	7.35
13-Jan-04	7.33	3.05	1.17	3.19	5.9	6.59	7.4	6.45	6.04	6.35	6.33
14-Jan-04	5.76	3.67	2.41	2.26	5.28	5.73	5.56	5.68	6.02	6.14	4.17
15-Jan-04	4.85	2.84	1.04	1.07	1.64	3.36	4.17	6.35	6.57	7.69	5.51
16-Jan-04	2.74	0.64	3.7	4.63	7	6.83	5.46	2.29	2.5	1.52	1.28
17-Jan-04	6.4	4.77	1.95	1.38	3.65	5.3	5.56	5.68	5.87	4.25	3.05
18-Jan-04	4.75	3.1	0.95	1.12	4.17	5.56	6.8	7.62	8.5	7.95	6.62
19-Jan-04	3.12	2.33	1.24	4.53	4.46	5.78	5.2	5.49	6.3	9.44	6.59
20-Jan-04	4.08	2.26	2	2.55	4.77	5.42	7.57	7.09	7.76	9.89	7.38
21-Jan-04	6.88	4.03	0.52	0.83	1.83	5.11	6.97	6.19	6.52	7.02	4.82
22-Jan-04	5.28	3.58	1.78	2.36	3.72	3.34	2.98	2.48	1.64	3.79	3.62
23-Jan-04	6.69	3.36	1.45	3.96	2.81	4.96	7.48	6.97	5.94	5.23	5.11
24-Jan-04	7.6	6.23	5.71	2.57	3.48	4.56	5.3	5.16	5.37	5.97	4.77
25-Jan-04	7.43	5.54	2.98	1.78	0.52	3.91	4.05	5.63	7.64	7.95	6.85
26-Jan-04	8.14	7.35	3.65	2.24	2.57	4.22	5.18	6.92	7.28	7.28	6.26
27-Jan-04	6.52	3.7	1.88	0.87	0.35	0.35	0.64	0.47	1.09	2.38	3.22
28-Jan-04	6.06	2.53	0.87	2.14	4.27	3.87	0.47	0.78	1.98	5.87	6.69
29-Jan-04	8.48	2.33	0.8	1.6	4.49	6.62	6.92	6.85	8.41	8.5	6.71
30-Jan-04	3.62	2.12	4.17	3.58	5.92	7.28	8.76	9.19	7.45	8.41	7.76
31-Jan-04	2.05	2.24	5.08	5.99	6.73	7.09	8.93	11.35	11.32	11.01	9.84
1-Feb-04	2.89	5.08	4.92	5.08	4.53	5.9	6.02	6.9	9.24	9.19	6.62
2-Feb-04	2.26	1.81	3.48	4.56	7.52	7.81	8.62	8.64	9.03	9.01	7.31
3-Feb-04	3.22	2.48	3.72	4.75	5.3	5.73	5.76	6.16	5.25	6.45	5.9
4-Feb-04	3.62	0.66	2.46	3.65	3.53	4.25	6.4	5.76	4.8	8	6.95
5-Feb-04	5.9	4.75	2.57	2.26	5.18	7.12	6.45	6.37	6.73	7.57	5.56
6-Feb-04	4.3	3.67	0.85	4.44	4.44	4.42	5.32	5.25	6.09	7.76	6.52
7-Feb-04	2.43	2.55	1.74	2.79	4.49	5.71	7.35	7.14	7.12	7.74	8.21
8-Feb-04	5.85	2.89	0.42	2.53	4.15	5.35	5.71	4.44	4.27	4.58	3.87
9-Feb-04	4.13	1.67	4.44	5.16	5.73	6.73	7.02	8.41	7.07	5.46	6.69
10-Feb-04	3.82	3.19	5.32	5.46	6.47	7.26	8.43	9.32	9.22	8.74	7.76
11-Feb-04	3.94	1.21	3.94	6.35	5.3	6.62	7.43	8.79	7.81	7.64	7.21
12-Feb-04	2.38	2.29	4.85	6.23	7.4	8.14	9.53	10.27	10.99	10.46	8.46
13-Feb-04	1.07	2.21	5.83	6.71	7.57	8.81	8.84	9.75	9.1	10.96	10.13
14-Feb-04	1.04	3.51	5.85	6.09	7.81	9.17	9.27	10.25	10.2	11.47	10.37
15-Feb-04	1.33	4.2	4.46	7.78	7.9	5.99	6.69	8.69	9.62	9.77	7.93
16-Feb-04	3.05	3.34	5.76	5.68	7.24	8.41	8.48	7.95	7.45	9.82	8.53
17-Feb-04	6.11	2.5	2.38	5.13	5.68	7.28	8.67	9.67	10.68	10.27	5.63
18-Feb-04	4.25	0.78	2.46	2.38	4.13	5.35	6.19	5.32	3.24	4.87	6.97
19-Feb-04	6.62	2.26	1.95	3.65	5.11	6.59	6.47	6.92	7.62	7.95	7.6
20-Feb-04	4.27	2.69	5.35	5.56	7.48	8.26	8	7.67	8.1	8.55	6.37
21-Feb-04	2.62	1.74	3.29	4.92	6.71	6.47	5.56	4.22	3.55	3.03	4.1
22-Feb-04	5.06	2.84	1.55	2.69	4.08	4.05	3.22	2.84	2.69	5.8	4.82
23-Feb-04	4.08	1.33	2.72	5.06	5.78	5.97	4.42	4.08	3.58	5.85	5.28
24-Feb-04	6.14	4.03	3.01	3.46	4.27	4.65	5.44	6.97	7.9	7.95	8.19
25-Feb-04	7.26	3.6	1.88	4.89	4.92	6.64	5.85	6.45	6.76	6.97	6.49
26-Feb-04	4.94	1.26	2.81	4.85	6.21	7.09	6.49	6.76	8.12	8.53	7.76
27-Feb-04	6.8	5.68	1.78	3.98	3.91	4.92	6.09	6.37	7.14	8.36	7
28-Feb-04	1.95	1.47	2.67	4.58	5.32	6.54	7.76	8.5	7.09	6.83	7.43
29-Feb-04	3.44	1.55	5.01	5.23	5.3	5.9	6.83	9.58	9.17	9.58	8.36
1-Mar-04	0.8	1.88	5.54	5.97	7.4	8.14	7.24	7.28	7.52	9.1	8.31

12	13	14	15	16	17	18	19	20	21	22	23	24
3.29	1.6	3.01	7.45	10.18	10.94	10.82	11.32	12.49	13.26	10.89	8.31	6.28
2.86	1.83	6.16	10.08	11.71	12.02	11.8	12.49	13.14	12.07	9.7	8.43	6.35
4.05	1.67	7.81	10.89	12.21	13.5	13.07	13.74	14.03	12.54	10.01	7.4	4.05
3.7	2.55	7.4	10.8	11.92	13	13.31	13.05	12.19	13.33	11.51	8.46	5.85
2.96	6.54	10.3	10.87	12.4	12.88	13.21	13.6	13.71	13.07	10.75	7.21	5.13
5.28	8.41	10.68	12.35	13.78	14.86	15.32	14.89	13.38	11.47	9.24	7.74	6.64
2.84	5.13	9.05	11.97	12.88	13.93	14	12.47	13.26	14.5	11.51	9.75	6.73
2.14	5.39	9.29	11.42	12.49	12.8	12.21	11.54	11.92	11.49	11.11	9.24	7.64
1.19	3.91	8.36	11.68	13	13.02	12.76	11.42	13.35	11.97	10.7	7.64	6.19
1.19	5.71	9.7	12.59	14.05	13.38	12.59	11.59	11.59	8.93	7.83	7.28	4.46
2.29	1.9	7.43	11.08	12.8	13.26	13.67	14.31	13.55	11.61	9.27	8.84	7.12
4.08	2.17	7.38	10.37	11.18	12.23	13.05	13.26	13.35	11.87	11.94	10.75	8.43
3.19	2.79	4.96	8.07	10.8	11.49	11.28	12.23	10.3	9.17	10.68	9.39	7.81
1.64	5.35	9.12	11.16	11.73	12.04	11.13	11.01	9.58	8.53	8.91	9.84	8.24
2.07	1.31	5.83	9.72	12.28	13.67	13.35	12.09	10.68	10.92	10.87	9.39	6.37
1.88	4.13	7.74	10.44	11.8	12.92	12.69	12.4	11.73	12.11	11.94	9.55	7.55
1.47	3.98	7.86	10.96	12.76	13.02	13.26	12.54	13.02	12.52	10.35	9.03	7.21
4.96	2.12	3.65	9.15	10.87	10.99	11.71	11.66	12.45	13.62	10.42	9.29	6.59
4.39	2.12	2.43	7.43	11.59	13.35	13.86	14.38	15.51	14.03	11.51	8.24	5.83
5.49	1.98	7.24	11.97	13.86	14.1	13.69	13.38	14.34	14.12	10.46	7.78	7.64
1.98	3.15	7.55	10.22	11.64	12.16	12.09	12.64	11.92	12.78	12.73	10.78	8.05
1.81	5.23	7.67	9.29	11.25	12.21	12.26	12.21	11.54	11.54	12.33	9.22	8.33
2.24	3.34	7.93	10.35	11.83	12.47	13	12.35	11.18	10.61	11.97	9.98	8.76
2.93	2.21	6.49	10.22	11.68	11.78	11.37	10.99	11.37	10.92	8.93	9.12	8.64
4.27	1.52	5.23	8.57	10.01	11.18	11.8	12.14	12.45	11.08	10.2	11.56	9.05
3.36	1.5	3.15	8.1	11.61	12.59	12.23	11.97	12.23	10.82	10.49	10.89	8.6
2.79	4.42	8.67	10.2	10.51	11.13	12.42	12.8	13.57	13.55	12.57	11.71	9.7
4.13	1.21	4.8	8.91	11.66	12.04	11.8	11.66	11.83	11.54	10.32	9.82	8.72
4.73	1.88	4.68	8.48	10.3	10.87	10.18	10.03	9.17	8.96	9.84	8.43	7.14
4.51	1.57	3.91	7.74	8.79	9.46	9.65	10.68	10.32	11.94	12.09	9.65	7
6.78	2.05	2.5	8.64	13	14.24	12.57	12.11	13.67	13.26	8.96	8	4.94
3.67	1.95	5.9	9.05	10.89	12.3	12.64	12.54	11.54	11.04	11.32	9.27	6.42
3.94	1.47	4.99	9.58	11.99	13.55	13.81	12.26	10.27	9.27	9.03	8.98	7.28
4.25	1.28	8.1	11.01	13.05	13.67	13.98	12.8	11.04	9.03	7.83	8.55	6.42
3.91	1.19	6.71	10.63	12.02	13.07	12.92	13.33	12.76	12.52	12.54	9.34	7.48
2.69	3.24	6.64	10.03	11.8	12.11	12.23	11.97	11.78	11.99	10.1	8.05	5.2
4.34	1.52	5.94	10.1	11.87	12.73	13.12	13.31	12.07	11.64	10.49	8.64	5.73
5.49	2.55	5.16	9.82	11.35	12.37	12.3	12.33	12.23	11.68	10.63	10.56	8.36
2.03	2.26	4.87	8.98	11.32	12.11	12.19	13.35	11.01	10.73	9.32	8.6	6.62
4.37	1.62	5.28	7.93	9.94	10.27	9.96	9.58	10.15	10.3	11.16	8.19	6.26
4.56	1.24	5.39	8.98	10.61	11.32	11.68	11.66	10.82	11.75	10.85	9.15	6.47
4.68	1.33	4.46	7.07	9.01	8.98	9.48	9.6	9.36	9.48	10.68	9.48	6.92
7.26	3.94	3.34	6.69	9.75	10.94	11.68	11.94	10.89	9.55	9.03	8.05	5.56
7.24	5.01	2.98	7.19	10.08	10.51	9.96	9.75	9.58	10.32	10.37	9.24	6.4
7.76	4.01	3.34	8.57	10.1	10.32	11.01	11.39	11.28	10.27	9.15	7.57	3.77
5.92	2.26	3.29	7.64	10.15	11.18	11.71	11.66	11.42	10.32	10.75	8.84	6.92
5.85	2.17	1.69	6.62	9.58	10.51	10.78	10.22	10.15	9.08	8.67	9.01	7.33
2.24	4.82	8.93	10.05	10.8	11.8	11.87	11.25	11.73	10.56	9.84	9.82	7.19
3.89	2.24	3.19	8.1	10.08	10.8	10.3	11.01	10.27	9.17	8.98	9.48	9.22
5.28	2.14	4.44	7.86	10.01	10.68	11.11	11.3	10.96	9.79	12.59	9.82	7.57
3.15	1.35	6.97	10.51	11.87	12.42	12.04	11.04	10.78	11.99	10.89	9.6	6.69
1.31	3.79	7.88	11.18	13.07	13.6	13.21	12.88	12.26	11.13	9.39	8.69	7.21
1.81	3.03	7.24	10.2	11.85	12.73	13.23	11.75	12.26	12.16	9.55	9.19	6.49
3.55	1.43	5.83	9.39	10.49	11.9	12.57	12.28	12.21	12.76	11.66	8.64	7.6
5.63	1.26	5.08	9.67	12.09	12.64	12.3	12.45	12.47	10.87	9.05	8.69	7.71
5.37	2.76	1.57	8.33	12.47	13.38	13.19	13.14	13.45	13.28	12.02	9.87	6.64
5.61	2.91	1.6	8.21	11.87	12.9	12.47	12.64	12.64	12.3	11.21	8.41	6.95
5.25	1.43	4.92	10.1	11.99	12.04	12.11	11.18	10.94	10.94	11.01	8.21	5.51
6.09	2.29	1.28	7.05	10.22	12.28	11.54	11.04	10.51	12.4	11.44	9.44	6.76
5.2	1.98	4.27	8.03	10.2	10.87	11.06	10.94	10.92	11.83	10.65	8.96	2.86
5.46	1.57	3.91	8.64	11.16	11.59	11.83	11.64	10.99	11.32	11.06	7.74	2.62

2-Mar-04	1.88	4.68	5.54	7.6	8.5	7.57	7.71	8.26	8.93	9.27	7.6
3-Mar-04	0.78	1.17	2.84	6.19	7.09	5.78	5.99	6.45	5.44	7.64	7.81
4-Mar-04	1.57	1.78	1.55	4.68	6.66	6.49	6.28	6.83	8.33	9.17	7.95
5-Mar-04	1.98	1.71	2.98	5.51	5.61	5.44	6.49	5.66	7.52	9.82	8.64
6-Mar-04	2.17	3.77	5.97	6.95	7.98	8.69	8	8.74	8.76	9.1	9.24
7-Mar-04	1.45	3.08	5.37	5.78	7.45	8.43	8.41	8.91	9.17	8.62	8.91
8-Mar-04	2.46	2.12	2.69	5.44	7.07	5.94	6.49	4.65	6.52	7.83	8.12
9-Mar-04	3.22	5.87	5.76	8.17	9.12	8.91	9.36	11.56	11.8	11.83	11.39
10-Mar-04	5.83	5.2	7.88	8.89	8.38	11.21	10.49	10.42	10.99	11.23	10.46
11-Mar-04	2.96	5.78	7	8.19	7.93	7.98	9.7	8.31	9.94	9.96	10.2
12-Mar-04	2.36	6.11	6.21	7.6	9.32	10.68	11.59	12.57	13.88	14.12	12.4
13-Mar-04	3.1	5.94	7.64	7.55	8.14	9.44	11.16	11.64	12.14	11.47	9.39
14-Mar-04	2.72	5.56	6.42	7.62	9.6	10.51	12.49	11.56	11.28	11.18	10.05
15-Mar-04	2.53	4.65	6.06	8.03	8.57	9.87	11.8	11.16	8.6	11.51	11.25
16-Mar-04	3.05	4.22	5.66	7.38	9.15	10.61	9.89	11.3	12.85	13.21	12.76
17-Mar-04	4.68	5.37	7.83	9.44	9.89	10.92	12.35	13.67	14.24	13.33	12.37
18-Mar-04	7.05	7.5	9.48	10.94	11.64	13.05	11.8	11.92	13.4	14.6	12.04
19-Mar-04	5.9	6.3	8.17	8.96	10.89	12.04	12.26	12.8	13.93	13.16	13.09
20-Mar-04	5.71	7.52	8.86	9.65	10.89	12.16	11.78	12.45	12.64	13.12	11.06
21-Mar-04	4.87	6.42	9.1	10.15	10.46	11.54	11.97	10.65	9.58	11.28	10.08
22-Mar-04	2.14	3.62	5.37	6.83	8.41	10.03	9.34	8.57	9.72	9.91	8.03
23-Mar-04	8.55	7.64	5.35	3.31	2.48	3.44	5.32	5.92	6.83	5.08	3.17
24-Mar-04	8.48	6.47	1.19	4.92	5.2	5.85	6.9	4.27	3.44	1.28	2.6
25-Mar-04	1.98	1.67	4.37	5.71	7.38	9.51	8.79	8.81	7.31	9.22	8.6
26-Mar-04	6.64	9.36	11.54	11.21	11.85	11.64	10.7	11.37	9.94	10.15	9.55
27-Mar-04	5.42	5.85	7.38	8.17	9.32	11.28	12.88	13.12	12.66	12.71	12.09
28-Mar-04	6.16	5.99	7.64	8.6	8	7.62	8.24	10.87	11.49	11.25	10.13
29-Mar-04	3.17	2.38	5.66	7.26	7.98	8.53	10.58	10.65	8.81	7.67	7.57
30-Mar-04	6.78	7.05	5.18	5.92	4.89	5.42	6.92	8.12	8.64	10.25	10.92
31-Mar-04	5.54	6.26	6.66	9.46	9.53	10.96	11.39	10.94	11.42	10.25	4.82
1-Apr-04	4.39	4.99	7.98	8.03	9.12	9.53	10.75	11.64	11.39	10.15	7.24
2-Apr-04	4.25	3.36	7.4	7.9	8.64	8.89	9.96	10.89	6.14	9.44	10.1
3-Apr-04	10.8	9.75	10.53	9.29	8.53	6.09	4.15	1.76	4.32	7.78	9.46
4-Apr-04	9.84	9.82	9.32	9.87	9.19	6.42	3.17	3.46	8.38	10.89	10.68
5-Apr-04	8.76	7.86	5.18	5.18	5.35	3.48	1.76	6.33	9.24	9.46	9.89
6-Apr-04	2.12	1.78	0.37	2.31	2.57	1.71	0.71	2.55	7.88	11.32	12.09
7-Apr-04	6.8	7.31	6.64	7.12	7.12	4.68	1.31	5.23	7.31	9.41	11.32
8-Apr-04	6.97	6.45	5.35	4.94	5.3	4.17	2.57	3.7	7.86	10.32	10.32
9-Apr-04	10.8	11.49	10.03	9.91	8.38	5.11	3.27	2.55	5.97	8.57	9.46
10-Apr-04	10.87	9.84	9.7	9.51	10.15	8.86	3.79	3.84	9.22	11.94	14.53
11-Apr-04	5.61	5.78	4.32	6.83	7.86	3.27	6.64	11.87	13.6	13.88	13
12-Apr-04	8.38	9.58	9.84	10.49	10.96	8.5	5.03	1.95	4.8	9.44	10.51
13-Apr-04	9.98	8.69	10.7	10.18	10.7	9.51	5.8	2.5	6.83	8.67	12.04
14-Apr-04	9.89	10.94	10.18	9.53	9.29	7.9	4.94	2.76	7.07	9.6	11.06
15-Apr-04	11.37	11.87	12.02	11.92	11.87	8.46	4.01	1.88	4.7	7.5	8.38
16-Apr-04	11.49	12.26	12.42	13.19	12.16	9.79	5.28	3.05	7.57	10.3	12.16
17-Apr-04	2.19	2.41	3.34	5.01	6.52	5.54	4.68	3.94	1.86	4.53	10.08
18-Apr-04	7.55	9.39	10.3	10.99	11.13	8.33	6.37	3.89	4.13	7.55	9.34
19-Apr-04	11.78	11.51	11.68	12.16	10.56	6.9	2.74	2.43	5.25	8.29	8.79
20-Apr-04	8.64	7.95	8.21	7.62	8.46	6.06	3.53	2.1	4.58	6.28	6.62
21-Apr-04	12.8	12.73	13	13.67	12.4	9.44	6.83	2.79	2	2.91	6.3
22-Apr-04	10.53	11.87	13.12	12.16	8.91	5.83	3.55	2	5.25	8.69	8.6
23-Apr-04	8.03	10.56	11.13	12.28	12.14	8.98	4.77	3.01	7.14	10.75	11.39
24-Apr-04	10.39	10.22	10.94	11.59	10.92	8.86	6.78	3.03	3.55	6.49	8.21
25-Apr-04	12.14	14.26	13.91	15.55	14.41	10.39	7.05	3.91	1.74	2.1	3.6
26-Apr-04	12.37	12.23	12.11	11.08	11.32	9.15	7.21	5.87	11.42	9.1	9.72
27-Apr-04	7.83	7.35	5.56	2.79	2.05	1.74	7.19	8.96	9.41	8.86	9.05
28-Apr-04	6.16	7.31	8.24	7.86	7.35	5.66	2.19	5.23	7.43	8.86	8.81
29-Apr-04	7.24	6.69	6.83	9.34	8.29	6.35	3.53	1.55	3.15	7.76	8.55
30-Apr-04	9.96	10.37	11.11	10.37	9.1	6.69	4.25	4.1	8.74	9.65	9.1
1-May-04	2.26	4.51	3.36	1.43	1.26	2.21	11.06	12.04	13.5	15.75	16.2
2-May-04	2.72	1.4	1.64	2.29	1.43	3.29	6.02	10.1	11.47	12.62	12.76
3-May-04	1.02	2.17	1.24	1.02	2	2	3.94	9.03	12.28	12.85	12.14

4.53	1.47	6.09	9.65	11.97	11.94	11.85	11.66	10.2	9.58	9.6	7.78	2.43
4.17	2.03	7.05	9.65	11.73	12.57	12.14	11.99	11.04	9.24	9.1	9.36	5.59
4.65	1.5	5.11	9.91	11.59	12.52	12.11	11.61	10.13	9.79	9.44	8	4.17
6.62	3.7	2.53	7.67	10.56	11.37	11.85	11.13	10.46	11.68	8.67	7.16	2.81
8.72	4.27	1.33	5.94	9.44	11.04	11.71	11.32	11.01	11.35	9.67	8.48	3.87
7.12	2.5	2.05	7.45	11.06	11.87	12.28	11.68	11.08	9.62	8.98	7.02	3.34
5.9	4.27	1.69	6.62	9.89	11.94	12.09	11.64	10.78	9.6	7.14	6.28	2.1
9.19	4.87	2.05	4.65	9.39	10.1	10.13	10.44	10.65	8.98	6.97	5.49	2.96
7.35	2.33	3.72	6.42	8.36	9.6	10.65	10.08	9.89	8.96	9.89	7.12	2.19
7.64	3.55	3.08	5.51	8.86	11.08	10.25	10.25	10.18	7.95	6.54	6.45	2.72
8.07	4.7	1.33	4.42	8.03	9.34	9.94	9.82	10.68	10.22	8.64	7.95	3.91
6.8	4.82	2.93	3.7	7.86	10.53	10.32	10.68	10.22	9.44	10.51	7.5	5.51
8.43	4.3	3.41	6.64	9.46	10.05	10.39	10.82	10.7	10.03	8.62	9.6	6.23
8.46	4.53	3.08	5.61	8.19	9.72	9.87	9.94	10.08	9.05	7.83	7.43	6.02
10.03	5.99	2.91	6.52	8.81	10.08	9.98	10.35	10.25	10.1	9.1	7.64	6.73
9.89	5.61	1.62	4.96	9.22	10.42	10.25	10.3	9.77	8.46	8.43	3.51	4.34
9.05	5.73	1.6	5.71	9.27	10.8	10.94	11.01	10.05	10.08	7.95	7.26	2.36
9.98	4.99	1.81	7	9.94	9.84	9.84	9.7	9.48	9.03	9.67	6.52	1.83
8	4.3	0.73	4.37	9.36	10.82	11.42	10.58	9.34	8.5	7.95	5.71	2.24
6.37	2.41	5.2	8.67	10.99	10.63	9.82	9.36	8.98	8.29	7.83	5.68	4.44
5.28	2.67	5.8	8.31	11.06	11.64	11.11	11.28	9.67	9.72	9.65	10.08	8.91
2.98	7.98	10.63	11.49	10.46	10.56	10.42	11.16	10.22	8.86	8.31	7.88	8.5
2.57	6.06	12.69	13.48	14.81	15.37	14.29	13.6	13.05	10.58	9.19	9.05	3.82
6.57	5.03	2.48	2.65	7.57	10.03	11.11	10.32	9.29	8.79	7.21	4.56	6.37
6.76	4.68	2.65	7.12	9.41	10.56	10.27	10.51	9.48	8.1	7.31	7	2.86
9.65	5.23	3.17	8.89	8.64	9.48	9.53	9.7	9.67	9.1	6.06	3.91	3.74
8.26	4.2	2.46	7.83	9.48	10.49	10.32	10.39	9.58	8.24	6.49	5.35	4.94
7.21	3.55	2.07	4.82	6.04	6.37	2.43	4.82	4.82	1.57	0.61	2.17	4.42
8.48	6.02	2.96	3.74	9.87	10.56	10.68	10.39	10.15	9.41	7.81	4.7	2.07
2.67	5.25	6.57	7.28	8.64	8.72	8.36	8.72	7.5	7.26	6.19	1.4	3.87
4.6	1.4	6.92	10.18	11.61	12.04	12.66	12.76	10.99	8.31	4.7	2.12	0.97
10.13	10.03	9.65	8.26	5.9	4.05	3.39	2.19	5.37	6.35	9.36	10.05	10.51
9.79	9.34	8.46	7.76	8.72	5.87	3.34	1.57	4.32	6.57	7.93	8.24	9.01
11.01	10.75	9.36	8.33	4.94	7.21	7.93	6.85	2.74	3.19	5.63	5.28	5.94
10.46	9.84	8.41	8.46	6.69	2.79	1.95	4.51	5.9	6.66	4.13	2.05	1.5
11.37	10.51	9.82	7.9	7.64	8.48	5.92	4.34	2.38	0.69	1.5	5.85	7.48
11.3	10.46	10.53	10.1	9.82	5.85	3.46	5.66	6.11	6.97	7.57	6.21	5.94
12.14	13.5	12.45	10.89	9.22	5.73	2.31	3.96	5.39	6.42	9.41	9.53	9.98
10.18	9.44	9.82	8.84	8.6	6.16	2.46	3.41	3.29	6.37	7.86	9.03	10.56
15.24	15.37	13.07	11.47	9.75	6.95	7	8.36	5.87	5.46	3.91	0.92	2.19
12.49	12.14	10.92	8.84	5.11	4.77	3.48	1.67	4.42	6.33	7.26	7.24	8.69
10.96	10.18	9.51	9.84	9.1	6.19	1.24	4.37	5.83	7.55	8.72	9.29	10.61
11.73	12.92	14.17	13.02	6.35	2.93	4.03	6.8	8.1	7.81	8.81	8.69	9.87
11.28	11.23	10.51	8.24	5.37	2.96	4.03	4.94	6.85	9.41	10.18	11.39	11.35
9.17	8.38	6.73	6.62	8.12	3.65	3.46	6.3	7.62	9.75	8.6	7.86	10.44
11.75	11.16	9.41	8.24	8.14	4.87	3.72	6.09	5.23	6.95	7.88	7.43	5.11
11.37	10.89	9.19	6.26	4.32	2.6	2.79	3.51	4.03	5.9	8.55	7.45	7.35
9.17	8.6	7.62	6.83	4.13	3.77	4.89	6.97	7.95	8.98	10.1	10.63	10.75
9.27	8.48	7.52	6.62	8.6	5.11	2.29	4.27	6.11	6.26	9.29	9.91	10.1
7.07	7.33	7.5	6.73	4.05	4.03	3.36	7.05	6.33	9.1	9.94	10.56	11.49
6.54	7.35	6.52	7.52	7.74	6.23	0.92	4.51	6.3	7.81	9.03	10.73	11.75
9.89	11.59	11.37	11.59	9.62	8.05	2.1	4.39	6.95	9.12	9.44	6.57	7.4
10.94	10.01	9.39	8.64	5.8	3.6	2.38	7.26	6.62	8.03	7.55	10.68	11.18
6.92	5.94	7.95	8.64	6.33	1.12	4.44	5.51	7.74	9.55	10.58	11.66	12.69
5.56	7.6	7.16	7	6.71	4.73	3.87	6.54	6.49	7.83	9.79	11.39	12.78
12.11	12.35	11.61	8.1	8.98	10.56	8.62	7.45	5.3	1.74	5.11	6.49	5.9
9.75	9.7	8.74	7.09	7.62	6.04	5.16	5.85	6.49	2.07	2.5	4.03	6.02
9.05	8.43	8.81	6.23	7.14	4.3	1.78	7.81	5.49	5.46	7.21	8.57	6.76
8.76	9.65	8.76	6.14	5.25	7.19	3.31	3.72	4.96	5.85	6.47	8.14	7.78
10.1	9.39	7.86	5.49	6.92	6.47	4.63	1.81	3.87	7.81	7.93	7.12	4.15
16.03	12.33	11.68	9.67	5.61	2.86	1.57	0.49	1.21	1.76	1.5	1.28	2.53
14.31	11.99	11.59	8.74	7.31	5.59	3.08	2.55	2.29	5.16	5.13	2.96	2.05
11.28	10.94	10.37	10.01	8.89	6.28	1.45	4.85	6.92	7.52	9.17	9.05	10.46

4-May-04	10.87	11.49	11.21	11.99	10.7	7.31	6.04	4.65	1.57	4.92	9.58
5-May-04	9.94	10.94	10.63	10.65	10.61	8.62	5.54	2.55	1.38	4.25	6.47
6-May-04	8.62	10.27	10.44	9.84	9.77	8.19	6.35	3.03	1.81	1.62	7.76
7-May-04	7.98	9.27	9.51	9.19	9.39	7.78	4.46	2.19	6.57	10.75	11.66
8-May-04	5.3	5.63	5.39	5.32	5.13	4.99	1.67	6.19	7.6	7.83	6.66
9-May-04	5.92	5.66	5.46	3.29	4.37	2.53	1.6	2.81	4.99	9.77	9.1
10-May-04	9.22	10.03	9.48	9.6	9.36	7.07	4.85	3.82	8.96	10.85	10.89
11-May-04	6.92	6.8	7.12	5.37	5.03	4.51	2.76	11.18	13.78	14.53	14.12
12-May-04	4.77	6.78	3.24	3.03	5.85	6.76	4.68	6.59	11.44	10.27	9.94
13-May-04	7.67	8.14	9.44	9.7	9.19	7.24	4.89	3.24	7	8.81	9.48
14-May-04	11.83	11.54	11.99	12.02	13.45	12.42	8.79	5.2	1.88	2.81	4.85
15-May-04	12.19	10.85	11.35	11.35	9.91	8.17	7.19	5.18	2.48	4.56	7.45
16-May-04	11.97	12.66	12.07	14	13.16	9.62	6.16	4.08	2.1	6.4	9.96
17-May-04	10.63	12.45	12.62	12.35	11.61	9.82	7.55	3.74	5.46	10.53	10.44
18-May-04	9.24	9.79	8.46	6.95	5.9	4.25	3.48	4.96	8.1	10.03	10.46
19-May-04	9.29	9.6	9.19	9.67	9.48	7.71	4.77	2.21	5.28	7.78	9.72
20-May-04	10.22	10.61	11.35	11.23	11.13	9.46	6.21	2.48	6.62	11.35	11.11
21-May-04	9.22	9.08	10.49	12.04	12.37	11.3	6.64	2.17	5.08	9.62	10.49
22-May-04	7.52	8.55	10.1	10.39	10.03	9.36	6.02	2.36	4.37	7.09	9.03
23-May-04	12.45	11.99	10.42	11.25	9.34	8.53	7.26	5.28	2.36	4.3	7.62
24-May-04	11.04	11.28	10.96	12.07	13.12	11.13	6.83	3.05	4.96	7.74	9.41
25-May-04	6.88	7.05	8.36	8.79	8.69	6.35	2.81	1.78	5.76	8.5	9.36
26-May-04	1.47	3.89	6.97	8.48	8.36	5.94	2.76	3.27	6.09	12.49	12.62
27-May-04	7.57	7.14	7.12	6.26	2.96	2.12	4.01	6.35	10.7	12.28	12.54
28-May-04	6.42	6.59	7.88	9.19	8.5	6.19	4.51	5.66	7.35	8.62	10.44
29-May-04	11.68	11.51	13.07	13.64	13.81	12.04	8.46	5.32	2	4.22	7.24
30-May-04	8.86	10.27	10.65	7.88	8.62	8.17	3.67	5.13	7.57	8.55	9.91
31-May-04	6.28	6.26	8.24	8.19	8.86	6.11	2.14	4.68	9.41	10.1	9.6
1-Jun-04	10.44	8.07	5.99	7.76	10.01	7.16	4.56	4.17	1.93	3.51	2.96
2-Jun-04	10.61	11.8	12.23	13.95	13.5	12.62	11.68	8.05	5.13	1.38	1.67
3-Jun-04	15.2	16.23	15.24	15.51	14.74	11.99	10.89	8.24	4.77	2.86	1.76
4-Jun-04	17.68	15.84	16.25	16.87	17.18	14	10.03	6.9	2.79	4.68	6.06
5-Jun-04	14.91	15.01	14.34	14.36	12.92	9.94	3.62	1.95	6.59	9.75	10.13
6-Jun-04	14.29	14.94	14.67	15.39	13.76	12.26	9.94	6.49	2.29	5.18	8.21
7-Jun-04	13.33	13.52	14.21	13.78	14.03	11.47	8.81	6.11	2.81	3.91	6.4
8-Jun-04	11.11	11.8	11.21	11.51	10.3	7.86	6.62	3.53	2.69	4.05	4.39
9-Jun-04	13.6	13.67	14.21	14.34	12.97	9.94	8.12	7.86	11.78	11.32	10.3
10-Jun-04	10.75	12.07	11.54	10.61	9.1	7.88	5.94	3.46	3.98	7	10.73
11-Jun-04	8.76	9.46	7.76	9.72	11.18	9.96	5.94	2.19	7	7.52	7.9
12-Jun-04	8.93	9.51	8.89	9.46	9.98	8.98	5.66	2.81	6.3	8.48	9.96
13-Jun-04	4.85	4.75	6.19	7.52	7.33	3.62	1.02	1.78	5.18	10.32	11.64
14-Jun-04	10.85	10.25	8.64	8.41	7.95	6.09	3.15	6.97	10.63	11.18	11.3
15-Jun-04	2.62	2.46	3.34	4.65	7.28	6.14	2.6	2.48	3.91	5.01	5.71
16-Jun-04	4.56	2.17	2.65	3.05	3.67	2.36	2.41	3.01	9.46	8.26	8
17-Jun-04	7.62	7.6	9.79	5.73	5.85	2.91	4.22	7.88	8.36	7.83	7.12
18-Jun-04	7.35	6.21	8.33	8.57	9.84	8.12	8.64	9.79	9.44	10.89	10.94
19-Jun-04	4.75	5.35	6.66	8.33	7.55	8.43	6.73	4.8	2.69	1.55	2.91
20-Jun-04	9.53	10.3	11.18	11.78	13.31	11.99	9.12	5.01	2.12	2.57	5.76
21-Jun-04	10.56	10.8	10.82	9.32	10.51	7.19	3.84	2.79	8.21	11.37	11.66
22-Jun-04	11.61	12.64	12.59	12.76	14	11.51	8.64	4.32	2.65	3.08	5.03
23-Jun-04	10.7	10.42	10.53	12.23	11.83	10.27	6.28	3.53	2.62	8.19	9.08
24-Jun-04	2.19	0.92	3.03	3.94	6.42	6.69	5.68	4.44	3.72	3.27	5.39
25-Jun-04	11.51	8.98	9.79	9.98	11.59	9.6	7.38	6.42	3.53	3.39	4.15
26-Jun-04	11.28	10.2	11.21	11.32	11.85	10.92	8.36	6.16	2.55	4.01	8.96
27-Jun-04	10.03	10.03	10.73	10.05	10.51	9.51	5.73	1.6	2.5	2.74	5.9
28-Jun-04	12.04	12.19	12.83	13.23	13.38	11.54	7.5	2.79	2.76	6.23	9.34
29-Jun-04	13.31	13.23	13.23	13.31	14.43	11.78	7.52	4.89	2.6	6.19	8.19
30-Jun-04	13.45	12.85	11.54	12.16	10.92	8.6	1.69	2.31	5.32	7.86	8.93
1-Jul-04	10.22	10.35	10.13	10.8	9.67	8.33	5.01	1.83	3.58	5.18	6.8
2-Jul-04	10.01	10.85	10.96	11.78	9.82	7.26	4.27	1.52	4.15	6.8	8.24

11.06	10.73	10.68	7.76	4.22	4.32	3.15	2.48	2.62	6.06	8.79	9.41	9.96
8.33	8.72	8	11.13	9.82	7.28	3.65	2.03	2.03	7.19	6.52	7.19	8.91
8.69	7.93	7.9	8.31	8	6.97	4.3	2.48	6.37	5.16	4.68	4.75	4.7
12.4	12.47	10.27	9.32	8.36	8.89	3.17	1.55	2.41	3.1	5.9	4.82	5.16
5.59	5.61	6.33	7.4	7.4	6.78	7.62	4.25	1.31	1.07	2.31	5.42	5.99
8.14	7.4	7.95	6.19	2.38	2.1	2.07	3.79	6.54	6.76	7.19	8.36	8.03
11.16	11.28	11.47	8.84	6.19	3.96	4.2	2.29	4.05	4.99	5.06	6.23	6.73
13.28	11.49	9.94	8.72	5.61	4.56	1.81	0.85	1.47	1.64	1.07	3.29	4.63
9.27	8.57	7.43	5.85	5.16	5.42	1.93	2.57	2.48	4.1	6.28	6.19	6.02
9.46	9.01	8.76	7.74	7.26	3.31	3.46	4.73	6.59	10.13	10.68	9.44	10.82
6.78	7.45	7.38	7.48	4.73	1.52	6.78	6.83	8.76	10.18	11.16	11.68	11.92
8.81	9.29	9.98	10.3	9.48	7.4	4.89	6.76	7.52	9.55	10.92	12.49	13.26
10.75	10.25	11.68	10.03	9.98	3.6	4.37	6.42	8.05	8.46	9.39	10.63	11.06
10.25	12.69	9.27	8	9.24	8.5	4.2	3.77	3.89	3.51	3.08	2.79	5.87
10.05	9.79	8.19	7.07	6.88	3.03	2.07	4.2	7.14	9.53	8.81	8.72	9.01
9.84	9.6	8.96	8.48	6.8	1.24	1.76	5.76	7.95	9.62	9.48	9.87	10.13
10.3	9.87	8.91	6.47	3.48	2.46	5.51	7.09	9.24	10.87	10.87	9.67	10.2
10.2	9.41	7.38	8.41	8.46	2.17	2.12	4.27	6.45	8.76	9.91	8.43	6.62
10.35	10.32	10.15	7.76	3.79	2.67	3.29	5.63	7.6	8.21	10.15	10.96	11.47
8.72	7.95	7.74	7.4	3.41	5.03	6.76	7.98	9.17	10.68	8.89	8.76	9.77
9.39	8.91	8.19	8.31	7	5.46	2.12	4.7	7.81	7.88	7.76	6.02	6.54
9.24	10.27	9.55	9.77	9.05	4.3	2.67	2.89	2.89	1.4	2.26	0.71	0.85
12.28	10.94	9.6	8.17	8.69	8.72	9.32	9.58	8.84	3.89	1.17	2.38	6.33
12.45	9.94	8.96	9.03	6.28	4.96	1.9	2.69	3.19	3.1	4.42	7.14	7.33
10.68	10.49	9.84	7.98	4.49	3.29	4.92	6.04	7.67	10.58	11.61	10.08	10.87
8.64	9.19	7.57	6.21	2.98	1.95	5.11	8.03	9.12	10.8	10.3	6.71	8.72
10.1	9.15	7.95	7.4	5.83	4.56	4.92	3.03	1.38	2.31	3.91	6.9	6.85
9.39	8	7.16	6.37	5.06	4.77	3.74	3.39	3.65	4.42	7.98	7.45	9.53
3.34	2.03	1.33	7.31	5.35	5.56	8.03	10.96	12.07	12.33	12.23	11.78	8.41
6.49	7.45	7.28	6.85	2.26	2.98	8.48	11.13	13	13.5	13.78	14.05	15.96
8.81	8.69	9.34	9.22	4.99	3.05	8.24	10.2	12.64	12.83	13.64	15.27	17.01
7.67	8.24	7.93	7.14	4.27	5.11	8.14	9.51	11.25	12.83	13.83	14.55	15.51
9.22	9.53	8.81	7.93	2.36	3.39	7.19	8.03	10.63	12.69	13.19	13.88	14.79
9.65	8.98	7.62	7.02	4.05	3.77	6.97	8.46	10.13	11.06	13.05	13.78	13.67
7.57	7.5	7.62	5.3	3.44	2.74	6.3	8	8.79	10.01	9.44	12.33	11.87
8.17	7.71	7.07	7.43	1.98	1.28	6.16	8.67	9.65	11.61	12.26	13.21	13.55
11.28	9.75	8	7.81	6.16	2.84	4.3	4.92	6.88	7.93	7.93	9.53	9.67
11.32	10.05	9.27	8.29	4.7	1.76	2.81	5.68	5.92	7.69	8.98	7.38	8.64
8.46	7.88	7.76	5.78	3.27	0.52	4.1	7.14	6.95	7.24	6.62	8.93	8.36
8.36	6.23	4.65	3.98	5.71	3.44	0.85	1.81	4.65	5.44	4.58	5.66	4.25
9.39	9.96	7.19	7.12	7.5	2.98	3.1	6.54	6.47	6.26	6.49	8.6	9.36
10.01	9.24	8.07	6.8	3.94	3.1	2.48	1.88	2.07	2.1	5.35	2.67	2.65
6.76	4.1	5.13	3.17	3.72	3.1	3.29	2.69	5.25	2.86	3.7	2.31	3.96
9.12	9.08	7.48	5.66	5.28	5.83	6.62	8	10.92	8.62	6.35	7.28	9.89
8.74	10.92	10.8	9.77	9.44	6.66	5.63	2.62	3.87	6.3	7.55	7.09	6.21
12.95	11.04	9.98	8.69	10.63	12.54	11.54	11.21	13.5	9.15	5.06	4.13	4.37
2.29	2.74	4.7	6.62	3.6	1.81	7.07	9.27	11.42	12.69	12.23	9.1	8.86
8	8.43	6.95	5.16	2.91	2.46	2.62	7.31	9.32	10.3	10.56	9.6	9.94
11.16	10.39	9.27	7.05	5.97	3.19	2.48	9.41	9.91	11.08	11.06	11.73	11.73
7.55	8.26	7.88	6.52	6.21	2.5	2.43	7.5	8.1	9.32	9.34	9.84	9.58
10.8	9.58	10.8	11.78	9.82	7.33	2.38	4.51	2.6	3.27	3.98	2.79	2.14
6.92	6.28	6.06	6.33	5.35	5.3	3.96	2.69	5.18	5.76	8.76	10.75	12.02
4.99	6.4	7.4	6.66	6.73	4.53	6.09	7.6	8.21	9.29	10.65	10.89	10.85
9.48	8.67	8.14	6.11	4.17	3.36	3.41	4.87	6.42	8.79	10.18	7.57	9.48
6.78	7.48	7.69	6.57	5.37	4.82	1.62	6.4	8.29	8.36	10.27	11.83	11.87
9.46	9.82	8.84	8.38	6.26	4.96	3.6	7.62	7.71	8.84	10.73	10.96	13.12
9.27	9.08	8.17	7.26	4.27	2.72	2.55	6.04	8.36	9.84	12.33	12.8	12.8
8.6	8.21	6.62	5.42	4.96	2.46	0.85	4.82	5.94	7.6	9.03	9.79	9.53
7.76	7.12	6.62	5.08	4.3	8.19	4.51	3.12	5.3	5.61	8.05	9.22	10.01
9.05	9.77	9.44	7.76	7.21	9.36	7.26	3.51	4.39	8.41	7.35	6.52	7.67

3-Jul-04	8.43	8	7.95	7.74	7.69	6.04	3.44	2.48	4.96	9.44	11.83
4-Jul-04	4.49	6.71	7.57	7.48	6.76	5.76	2.14	2.89	7.33	8.21	8.6
5-Jul-04	11.35	9.91	9.29	9.53	9.75	7.43	3.51	6.95	11.42	11.13	11.39
6-Jul-04	4.89	8.84	7.48	6.28	7.98	7.71	4.75	3.1	6.4	10.39	11.42
7-Jul-04	7.28	8.03	9.03	8.76	8.07	7.12	3.34	3.6	6.73	8.67	8.07
8-Jul-04	10.61	10.32	9.51	9.53	9.24	6.83	2.57	7.12	7.78	8.86	9.67
9-Jul-04	8.12	8.19	8.29	9.77	10.68	8.72	3.72	4.82	7.5	9.62	8.38
10-Jul-04	11.3	11.35	11.68	13.62	14.86	12.16	9.55	6.42	3.48	1.74	2.5
11-Jul-04	12.21	11.71	11.23	10.46	9.89	7.6	4.42	2.46	4.65	7.76	10.56
12-Jul-04	8.91	9.98	10.92	11.3	10.96	7.6	4.39	2.14	5.92	9.91	9.87
13-Jul-04	6.57	6.52	7.78	8.84	8.84	7	3.79	6.21	12.66	12.19	12.85
14-Jul-04	7.5	7.16	7.12	6.9	6.57	3.72	2.43	10.78	11.9	12.35	14.81
15-Jul-04	9.87	9.15	6.69	7.81	6.49	4.73	2.79	4.75	6.42	7.69	9.08
16-Jul-04	11.23	11.47	11.32	12.07	11.64	8.79	4.1	2.24	4.96	8.17	9.36
17-Jul-04	8.53	7.83	8.26	7.76	9.27	7.24	4.87	2.6	6.62	8.6	9.27
18-Jul-04	7.21	7.5	4.25	3.27	2.53	1.98	2.96	4.49	6.19	9.82	10.3
19-Jul-04	10.25	11.73	11.47	12.71	11.06	9.34	6.76	3.24	2.21	1.76	3.39
20-Jul-04	13.5	13.26	12.28	11.47	12.11	11.51	7.64	3.77	1.76	6.71	10.42
21-Jul-04	10.49	11.75	12.02	12.83	12.19	8.91	5.97	2.43	3.91	7.86	8.55
22-Jul-04	9.27	8.62	8.36	7.21	9.91	7.55	5.85	4.3	2.07	3.6	5.83
23-Jul-04	12.16	14.34	14.05	14.5	15.01	11.64	8.64	5.76	3.29	2.33	3.94
24-Jul-04	14.17	15.34	15.51	14.53	14.26	12.54	8.19	3.72	1.69	5.61	9.51
25-Jul-04	14.84	14.46	14.05	13.52	13.31	10.87	7.93	4.32	1.6	1.24	9.39
26-Jul-04	15.39	15.53	12.8	14.03	12.71	9.96	5.87	1.69	7.28	8.93	9.32
27-Jul-04	12.85	12.52	12.4	11.99	11.49	9.53	6.09	2.03	4.22	7.5	9.34
28-Jul-04	12.52	12.59	11.18	10.82	10.85	9.34	6.49	2.33	3.46	9.12	10.58
29-Jul-04	11.64	11.39	11.97	12.21	11.42	10.2	6.37	2	4.44	6.06	5.99
30-Jul-04	13.28	12.95	13.81	13.78	12.19	10.05	5.83	1.6	6.54	10.18	8.72
31-Jul-04	10.82	10.13	9.58	11.35	11.01	7.52	3.03	2.29	6.62	9.12	9.65
1-Aug-04	10.46	9.84	6.59	7.6	8.6	3.77	1.71	6.23	6.59	9.36	10.44
2-Aug-04	7.43	8.69	8.96	8.98	9.39	6.62	2.38	5.78	9.03	10.35	10.99
3-Aug-04	9.24	9.84	10.65	10.85	10.99	8.62	3.36	1.81	6.49	9.53	10.18
4-Aug-04	11.97	12.42	12.19	11.61	11.08	8.38	5.63	2.91	1.98	4.89	5.49
5-Aug-04	13.16	14.12	14.19	13.86	11.49	5.92	3.79	4.7	6.71	9.27	7.9
6-Aug-04	9.79	11.97	12.69	13.23	11.97	9.58	5.87	2.72	3.05	7	10.03
7-Aug-04	11.87	13.38	13.69	12.76	13.33	11.06	6.23	4.1	2.43	2.72	8.5
8-Aug-04	12.21	11.75	11.92	12.69	9.46	7	3.1	3.89	7.88	9.7	10.56
9-Aug-04	3.29	1.35	2.41	4.15	9.24	5.63	3.22	2.05	5.61	9.19	9.79
10-Aug-04	6.85	3.08	3.01	7.14	6.09	2.1	5.49	7.95	11.11	12.42	13.16
11-Aug-04	2.33	6.19	5.39	4.58	3.65	3.79	12.26	14.77	15.37	14.74	14.05
12-Aug-04	9.7	8.67	8.14	9.58	10.15	4.44	1.69	5.44	8.76	9.75	10.44
13-Aug-04	7.48	9.34	10.08	11.28	10.58	8.03	3.15	5.3	10.03	9.87	10.32
14-Aug-04	8.5	9.75	11.18	11.85	10.87	8.62	5.56	2.43	5.06	9.08	9.62
15-Aug-04	10.3	10.87	11.47	9.98	9.36	6.62	4.03	1.81	4.01	5.35	7.19
16-Aug-04	12.28	12.21	13.57	13.35	11.35	8.96	5.06	2.21	8.98	8.33	8.76
17-Aug-04	11.49	11.42	10.61	9.55	8.05	5.8	2.89	1.88	4.94	6.92	7.88
18-Aug-04	9.77	10.37	10.96	11.54	10.85	7.12	4.08	3.39	5.61	7.64	6.8
19-Aug-04	8.12	9.08	9.89	9.67	10.22	7.76	4.22	3.53	7.52	10.78	12.52
20-Aug-04	7.86	5.8	4.08	4.39	4.25	4.94	3.79	2.38	4.22	6.97	9.41
21-Aug-04	7.88	10.22	11.83	13.14	11.23	7.38	5.16	2.1	4.68	8.03	9.79
22-Aug-04	12.57	11.9	12.47	13.21	10.94	8.12	3.6	2.38	5.18	7.88	7.86
23-Aug-04	10.99	10.35	11.51	11.06	9.6	7.48	3.72	2.21	4.05	6.42	8.29
24-Aug-04	8.62	8.93	9.34	9.53	9.03	5.63	3.24	2.17	8.36	9.32	9.72
25-Aug-04	8.31	8.91	10.39	9.19	8.89	6.78	4.6	2.33	4.6	8.43	10.44
26-Aug-04	11.56	12.35	11.71	12.26	10.08	5.42	2.17	3.7	8.14	11.35	11.97
27-Aug-04	9.98	9.84	9.01	6.64	8	5.56	2.57	7.67	8.96	10.18	10.78
28-Aug-04	12.28	13.09	12.19	11.92	10.99	5.76	2.46	4.37	9.27	9.22	10.01
29-Aug-04	10.27	9.65	8.93	10.85	10.08	7.43	4.25	3.7	7.57	10.03	9.87
30-Aug-04	9.62	8.46	9.24	10.13	7.83	4.89	2.24	3.15	8.79	12.42	11.99
31-Aug-04	12.37	12.9	13.19	13.83	11.47	7.07	2.81	4.53	8.1	10.44	10.49
1-Sep-04	7.26	9.29	8.62	9.39	8.86	4.42	3.27	8.89	10.35	10.87	11.49
2-Sep-04	9.39	11.32	12.3	11.75	10.08	6.78	2.5	4.1	7.19	8.76	7.74
3-Sep-04	11.85	11.87	12.88	12.76	11.06	8.26	4.63	2.33	4.8	7.81	8.64
4-Sep-04	11.87	12.66	12.85	13.23	11.04	7.38	2.07	2.84	7.83	10.03	10.75

12.73	11.99	10.8	9.77	8.48	7.24	5.54	1.74	1.24	4.82	6.47	6.26	7.33
7.48	7.28	7.4	5.61	4.46	4.85	4.13	6.14	7.62	9.32	10.61	11.16	11.78
12.16	11.47	11.04	8.98	9.53	10.18	8.38	4.15	1.9	3.62	1.35	2.07	3.19
11.11	9.39	8.76	9.98	10.05	8.89	4.13	1.09	3.96	6.52	7.86	8.41	7.81
7.38	8.91	8.6	9.53	3.51	3.82	5.03	5.66	7.83	9.27	9.79	9.39	9.41
10.13	9.87	9.12	8	9.46	8.33	6.78	1.78	1.38	4.89	6.66	8.1	7.57
8.33	7.74	7.78	9.08	6.69	4.46	4.89	6.97	8.5	9.79	9.72	11.11	11.8
4.53	5.83	7	7.28	4.56	3.01	4.27	9.72	10.58	12.54	12.9	12.52	11.83
11.73	9.75	8.79	7.88	5.61	5.18	3.67	2	2.98	5.9	8	8.64	7.74
10.65	10.46	8.86	9.32	9.29	7.38	4.01	2.96	3.7	3.05	2.17	3.72	6.06
11.94	10.87	10.13	7	6.57	4.82	1.47	2.24	5.37	6.04	7	7.19	7.28
14.03	13.83	11.78	9.17	8.31	2.84	4.2	1.57	3.22	4.56	6.66	7.45	7.12
9.53	10.13	10.03	7.62	5.99	3.01	1.31	4.53	8.29	8.69	10.27	10.49	10.87
9.67	10.58	8.93	7.74	5.06	3.94	3.74	3.24	6.49	7.62	7.78	9.65	9.91
9.27	9.62	9.67	7.55	6.16	3.82	4.03	1.57	4.08	4.77	5.35	5.78	7.74
10.15	9.27	8.38	7.24	8.05	8.36	6.85	3.53	2.76	6.64	6.59	6.28	7.26
5.49	6.37	5.78	5.61	3.96	2.05	4.73	7.35	9.94	10.13	11.9	13.33	12.76
10.22	8.98	6.59	5.16	3.89	3.27	4.3	4.96	6.88	9.12	9.91	10.1	11.3
7.05	6.35	5.76	5.39	3.89	1.88	3.1	6.52	7.28	9.27	9.7	11.11	10.39
6.83	7.86	6.62	5.16	3.27	1.02	4.51	9.17	9.22	11.23	11.35	10.8	10.89
6.64	8.33	9.65	10.18	8.14	5.2	1.17	6.21	8.1	10.51	11.92	12.02	12.83
10.32	9.98	9.46	8.19	6.66	5.42	2.36	5.78	6.92	9.77	11.85	13.33	13.64
9.41	9.62	9.75	10.25	8.21	3.29	4.08	6.52	8	10.53	12.59	14.55	15.22
10.2	10.73	9.79	7.24	3.36	1.93	4.17	7.31	8.96	10.85	11.37	11.94	11.51
9.79	9.34	9.01	8.41	6.95	2.67	3.27	5.56	6.97	8.41	9.94	10.58	12.28
10.18	9.03	8.21	8.19	4.77	1.45	3.24	4.94	6.92	9.48	10.27	11.23	12.02
7.88	6.88	6.9	8.53	6.42	3.44	5.11	7.67	7.71	9.51	10.2	11.25	12.66
7.81	8.03	7.69	7.35	10.51	7.35	4.51	4.82	6.33	6.57	8.36	9.84	10.03
9.22	10.35	9.34	9.29	7.33	3.31	2.24	5.11	7.4	7.95	9.96	10.37	10.7
11.54	10.13	8.5	6.26	4.87	1.67	1.26	3.31	6.9	9.29	8.43	8.81	8.1
11.08	10.46	9.34	8.74	7.9	2.91	2.38	6.8	7.95	6.09	7.95	7	9.6
9.96	9.39	9.01	8.41	7.24	4.63	1.83	5.51	7.35	8.5	9.24	11.28	10.96
7.26	8.03	7.74	8.72	6.64	5.76	4.49	4.99	4.34	6.4	8.43	10.94	12.62
8.07	7.64	7.07	6.9	6.42	5.63	4.22	7.83	8.26	9.84	10.94	9.67	10.73
9.7	8.31	7.5	7.07	8.12	5.46	2.14	5.28	6.59	8.1	9.65	11.8	11.9
10.01	9.87	9.87	10.25	10.25	7.78	1.86	2.67	5.87	7.55	10.25	12.16	12.54
10.65	10.15	9.41	8.53	6.35	3.19	1.93	4.44	3.31	7	10.03	10.89	6.64
10.27	7.86	7.83	7.35	5.11	4.1	5.11	5.61	1.45	1.98	5.2	6.47	7.4
14.14	14.38	10.8	5.92	2.6	2.33	3.87	5.06	2.07	3.08	4.22	4.63	5.63
12.9	13.45	11.13	11.66	10.68	6.26	5.85	5.71	3.19	5.03	7.16	8.36	8.03
11.04	11.21	10.61	8.91	7.57	6.88	6.14	1.9	3.91	6.62	7.26	8.19	7.12
10.63	9.67	9.67	9.67	7.5	5.49	2.81	3.65	6.06	6.59	7.62	8.31	8.12
9.62	8.84	8.17	7	5.37	5.06	3.46	4.49	6.11	7.45	9.27	10.82	10.15
7.6	7.43	7.74	6.95	5.01	6.64	6.19	3.58	3.6	5.28	6.28	9.89	11.28
9.67	9.24	8.21	8.72	7.55	4.25	4.03	5.13	7.76	7.52	7.86	9.36	11.37
7.95	7.64	7.5	8.69	10.78	7.5	6.76	5.01	2.72	4.39	5.46	7.02	9.32
6.66	7.67	8.33	7.62	7.31	6.4	4.8	3.51	5.32	6.85	5.73	9.08	9.22
12.83	11.39	9.75	10.94	9.55	9.89	4.87	2.74	3.41	3.36	3.62	3.87	2.41
9.7	9.65	9.08	9.53	6.8	4.03	2.91	4.94	5.83	7.26	7.81	8.55	7.45
9.58	10.08	10.42	9.98	7.76	5.35	1.52	4.96	5.99	7.21	9.39	9.91	11.51
7.95	7.76	8.19	7.83	6.64	4.37	2.6	5.61	7.67	7.98	9.7	10.63	10.65
10.32	11.23	11.16	10.08	10.27	8.29	5.9	3.79	2.98	4.56	3.82	5.78	9.22
9.34	8.86	8.38	7.48	7.69	7.83	4.2	1.45	3.91	4.34	6.64	7.12	8.96
10.94	11.44	11.47	10.46	10.15	3.46	3.03	6.09	6.11	6.83	6.52	8.62	10.61
11.99	12.14	11.37	11.68	8.12	6.35	3.29	3.39	4.58	5.11	8.43	9.53	10.35
8.5	7.83	8.53	6.95	4.75	4.1	3.79	2.91	4.32	6.8	8.12	9.55	11.18
10.51	10.94	10.46	11.16	12.3	4.73	2.81	1.93	5.97	5.01	5.87	9.03	10.18
11.3	11.32	10.51	11.44	8.81	6.71	3.27	3.15	4.6	5.23	7.62	8.43	8.74
10.89	10.37	10.46	7.88	5.37	6.21	3.58	4.51	5.25	6.92	9.01	10.03	11.01
12.3	11.39	11.23	9.17	6.4	7.16	6.37	3.29	2.29	3.34	5.92	8.33	8.81
11.37	11.25	9.27	6.73	5.8	6.57	5.06	0.95	5.18	5.35	5.42	5.87	6.02
7.62	7	8.53	8.76	7.93	6.49	2.65	3.31	7.31	8.67	10.3	10.65	11.42
9.62	10.25	10.35	8.93	8.43	7.93	3.15	4.75	6.35	6.37	8.6	10.27	11.42
11.56	11.49	10.68	10.27	9.51	8.6	5.39	3.29	5.73	6.83	6.8	9.17	9.65

5-Sep-04	10.51	11.32	11.11	11.23	9.24	6.57	3.15	4.34	9.29	11.47	10.96
6-Sep-04	9.55	8.86	10.99	11.66	9.44	6.69	5.28	2.81	2.36	4.63	6.33
7-Sep-04	11.9	12.37	13.45	12.76	10.51	6.71	3.12	2	5.18	10.18	12.04
8-Sep-04	7.07	9.65	10.63	9.82	8.69	3.84	2.1	5.99	8.67	10.22	11.59
9-Sep-04	8.81	9.98	9.82	9.84	8.74	6.19	2.62	2.62	4.63	8.33	10.51
10-Sep-04	8.29	10.1	9.96	9.53	7.98	5.25	3.36	2.1	5.2	9.82	10.03
11-Sep-04	9.51	6.78	9.15	10.61	6.19	2.74	2.41	6.92	9.48	10.65	11.39
12-Sep-04	7.5	6.47	8.29	10.13	6.69	2.6	2.84	6.69	8.81	11.06	11.21
13-Sep-04	8.29	7.62	6.71	5.51	2.98	2.89	2.93	5.13	5.71	6.37	8.89
14-Sep-04	8.24	7.31	8.93	9.98	6.8	2.76	3.44	6.52	9.19	12.02	11.99
15-Sep-04	8.38	6.57	2.72	3.72	4.37	2.89	2.46	6.14	8.62	10.75	11.37
16-Sep-04	9.36	10.49	11.47	10.8	8.5	6.26	3.29	3.31	7.9	10.94	11.23
17-Sep-04	10.82	9.15	10.32	11.32	8.69	5.46	2.57	2.69	5.03	6.85	8.96
18-Sep-04	11.39	12.45	12.37	12.47	10.56	7.05	3.1	5.13	9.05	9.77	10.15
19-Sep-04	9.41	11.06	9.65	10.7	8.36	6.33	3.34	1.6	4.85	7.9	9.08
20-Sep-04	12.42	12.47	12.95	13.93	11.01	6.8	3.98	2.69	2.57	4.96	9.12
21-Sep-04	10.78	11.13	11.61	10.99	9.1	6.49	2.57	2.17	4.6	8.36	10.35
22-Sep-04	6.85	7.88	8.62	8.96	6.57	3.34	1.38	2.48	5.76	8	9.62
23-Sep-04	5.73	6.3	7.19	8.19	6.33	3.51	2.96	1.67	4.85	6.9	8.05
24-Sep-04	10.78	10.13	11.64	11.28	8.48	6.85	3.44	2.57	4.01	6.52	7.4
25-Sep-04	6.26	7.67	9.62	10.3	8.43	5.85	2.93	2.19	2.29	5.78	9.36
26-Sep-04	9.84	10.65	9.7	9.17	8.1	7	3.01	7.28	10.53	10.35	10.27
27-Sep-04	1.71	4.49	9.08	7.14	5.61	3.05	1.81	2.55	4.3	5.71	8.91
28-Sep-04	4.96	6.9	5.9	5.73	6.19	2.31	2.62	6.59	9.15	10.96	12.16
29-Sep-04	7.76	7.38	5.97	8.81	6.73	4.13	1.12	3.87	9.55	11.44	11.3
30-Sep-04	5.01	5.94	4.7	6.88	5.11	3.46	4.2	7.95	10.61	10.44	10.94
1-Oct-04	8.46	10.51	11.08	10.53	7.64	4.15	2.53	3.03	5.35	8.74	10.51
2-Oct-04	8.67	9.75	10.56	10.8	7.09	3.7	2.03	5.42	8.89	10.46	10.92
3-Oct-04	8.24	8.64	9.01	10.08	8.29	5.8	3.22	2.05	3.94	6.02	7.12
4-Oct-04	10.25	11.85	11.99	11.99	8.96	5.28	2.81	1.93	8.24	12.09	12.35
5-Oct-04	9.44	9.44	12.26	12.02	4.08	6.02	9.6	10.25	12.04	12.85	13.19
6-Oct-04	6.71	7.26	5.68	5.3	5.2	1.93	2.03	5.68	9.51	9.91	10.68
7-Oct-04	8	8	7.45	7.64	5.66	2.14	3.58	7.43	8.53	10.44	11.28
8-Oct-04	6.49	8.03	9.19	9.7	6.37	4.08	1.78	4.01	7.69	8.6	9.17
9-Oct-04	9.6	10.25	11.28	10.58	6.92	2.1	1.9	6.52	9.48	10.89	12.26
10-Oct-04	7.78	8.17	7.93	7.83	3.65	0.54	3.05	7.02	8.96	9.82	10.3
11-Oct-04	8.48	9.87	10.82	10.85	6.78	3.19	3.98	8.38	10.2	10.18	10.89
12-Oct-04	8.17	7.6	5.54	7.16	5.37	1.86	4.77	7.88	9.29	10.92	11.56
13-Oct-04	10.42	10.1	10.05	9.44	6.64	1.9	3.89	8	9.55	9.91	10.89
14-Oct-04	8.21	8.62	9.19	9.91	7	4.1	1.57	7.38	9.58	10.56	10.65
15-Oct-04	7.64	8.17	10.22	9.22	6.85	2.72	1.12	4.17	8.26	11.06	11.71
16-Oct-04	7.81	7.21	8.64	8.38	4.87	1.74	4.46	6.73	8.79	11.04	10.68
17-Oct-04	8.57	8.84	9.55	8.64	6.54	4.15	1.69	3.19	6.62	9.51	11.68
18-Oct-04	8.21	9.34	9.03	8.79	6.73	2.26	5.03	8.05	10.46	10.82	11.42
19-Oct-04	10.63	11.85	12.23	11.66	8.29	4.17	3.6	7.5	9.51	9.24	9.12
20-Oct-04	10.89	11.21	9.94	10.53	6.95	3.41	1.19	6.76	10.42	11.16	11.71
21-Oct-04	6.14	6.4	9.75	8.53	6.37	1.45	5.97	10.2	11.04	12.28	13.16
22-Oct-04	5.39	5.94	7.21	7.62	5.13	2.41	1.74	4.94	8.33	11.08	11.51
23-Oct-04	8.19	9.75	10.61	9.87	6.73	2.98	3.98	7.4	9.24	10.37	10.18
24-Oct-04	8.72	9.32	9.82	10.42	7.19	4.32	1.88	4.75	8.31	9.75	9.6
25-Oct-04	9.94	11.49	10.99	10.46	8.26	4.77	2.38	5.46	9.39	11.56	11.49
26-Oct-04	6.92	8.43	8.86	9.15	6.92	4.8	2.81	4.68	7.05	9.17	9.67
27-Oct-04	9.53	10.58	11.13	10.53	8.67	5.3	2.33	4.03	6.9	9.77	11.11
28-Oct-04	5.71	8.14	8.79	7.24	6.88	3.77	2.67	4.51	5.97	8.84	10.08
29-Oct-04	6.47	7.26	7.9	6.69	4.68	2.57	2.57	5.92	9.96	10.61	10.27
30-Oct-04	8.86	9.87	9.7	8.43	6.47	3.08	2.14	7.28	10.32	12.35	11.47
31-Oct-04	8	9.36	10.78	9.15	6.83	4.25	2.89	7.02	9.44	10.89	10.63
1-Nov-04	9.34	9.84	10.75	10.2	7.81	3.72	1.45	3.22	7.26	10.78	12.11
2-Nov-04	9.51	9.7	10.2	7.64	5.85	2.38	2.5	5.42	9.12	10.39	11.21
3-Nov-04	7.35	7.62	8.72	8.43	5.97	3.17	2.17	7.21	10.94	11.71	12.11
4-Nov-04	8.64	8.1	8.29	8.29	6.37	3.44	2.1	7.35	10.94	12.45	11.85

10.35	9.44	10.05	8.76	6.57	7.02	6.59	3.12	4.34	5.35	7.98	9.27	10.1
7.88	8.5	9.53	9.27	9.32	6.3	1.35	3.12	5.94	6.9	8.69	10.13	11.01
12.04	11.87	12.54	11.23	10.35	9.17	4.15	0.92	5.16	6.02	7.48	8.81	7.33
11.85	11.85	10.44	8.72	9.77	7.48	2.81	1.12	3.94	5.32	6.88	7.74	8.1
10.03	9.55	9.62	9.22	9.44	8.57	4.25	1.4	0.69	3.82	4.51	6.59	7.64
10.63	10.37	9.89	8.6	9.15	8.03	4.05	2.6	3.94	5.18	6.11	8.43	10.22
10.94	9.1	8	8.24	8.33	7.12	2	2.81	4.05	5.9	6.85	6.47	6.14
10.42	10.56	9.79	9.87	10.65	9.17	4.27	2.53	2.36	5.32	6.95	7.21	7.64
9.51	10.8	10.73	9.29	7.83	3.31	3.89	2.05	5.35	6.28	8.07	8.55	8.36
11.64	12.83	13.09	12.49	11.16	10.75	10.99	7.48	5.99	2.55	3.58	7.62	9.1
11.71	11.28	11.87	11.97	7	1.55	1.14	3.58	5.61	7.24	9.75	9.36	9.55
11.94	12.64	12.26	9.58	7.28	6.23	4.46	2.41	4.15	5.54	6.95	7.78	9.7
10.03	9.7	9.58	9.96	9.27	6.3	0.87	4.37	5.37	7.55	9.08	9.41	10.8
10.94	10.51	9.53	10.87	9.39	7.83	4.42	2.1	3.98	6.04	5.73	8.69	8.98
10.18	10.05	9.72	9.98	9.34	6.3	4.46	5.71	6.33	6.59	9.24	10.78	11.73
10.49	9.44	9.36	11.39	11.25	7.81	4.25	3.82	6.62	6.62	7.78	9.24	10.58
9.91	10.13	10.42	11.61	9.79	6.57	5.32	2.6	2.36	4.51	6.97	5.87	5.99
10.63	9.84	10.22	12.33	12.8	9.84	8	6.57	1.71	1.33	4.56	3.98	6.4
8.89	9.53	9.41	10.78	10.7	9.82	7	1.69	5.87	5.54	7.16	9.96	10.25
8.64	8.98	8.96	8	7.9	7.35	3.1	4.25	5.8	7.16	8.29	8.43	7.62
11.73	11.97	11.54	12.8	9.46	7.33	4.22	3.58	2.96	1.93	2.05	5.68	8.55
9.75	11.04	10.1	8.17	5.44	2.72	1.86	7.78	9.15	7.86	6.42	2.65	3.84
10.15	10.96	12.59	9.7	7.21	6.11	4.73	4.37	2.03	0.78	4.01	6.04	5.16
11.3	11.11	12.37	13.52	10.87	8.36	7.31	4.51	2.43	4.46	4.53	4.6	7.21
10.39	10.82	10.46	11.64	10.75	9.03	9.05	7.07	3.72	4.08	4.2	3.94	4.92
10.85	9.94	8.72	8.21	8.57	6.73	7.12	3.82	3.44	4.05	5.85	6.26	6.45
10.37	10.92	13.02	14.79	10.27	7.52	3.82	2.69	4.63	5.25	6.04	7.57	7.76
11.23	11.64	11.16	12.04	10.82	8.74	5.49	2.41	3.55	4.2	4.63	4.89	7.57
7.83	8.72	8.57	8.93	8.33	8.17	2.69	3.34	5.3	5.32	7	7.57	9.41
12.66	13.74	14.55	11.44	10.1	7.6	2.5	2.1	2.1	5.44	8.43	7.98	8.55
13.38	13.26	11.8	9.75	8.29	10.99	10.03	7.4	4.27	2.38	5.03	5.37	5.39
10.92	11.59	10.8	11.06	8.46	6.04	3.6	0.8	2.43	3.87	4.8	7.09	7.43
12.92	12.59	11.54	7.4	5.13	5.97	4.42	2.57	3.19	2.93	1.57	5.37	4.94
9.01	8.57	9.46	11.71	10.3	9.41	6.97	3.74	3.17	4.1	5.25	6.78	7.9
12.54	11.28	13.14	11.54	9.58	8.55	6.06	1.52	2.86	4.58	5.59	6.23	7.09
10.63	11.25	10.63	12.19	10.18	8.33	4.63	2.46	1.45	4.25	4.32	6.09	7.02
11.68	11.83	12.35	12.64	11.56	8	5.03	1.28	5.99	5.32	5.39	7.05	7
12.14	12.42	11.78	11.23	10.01	8.24	5.44	3.29	4.22	4.63	5.99	6.71	8.33
11.11	11.21	10.78	10.08	10.18	8.93	6.57	3.46	1.26	2.6	4.37	7.5	8.05
11.35	11.37	10.75	8.91	8.17	11.78	9.15	4.15	2.14	3.77	4.22	6.88	7.07
12.28	12.3	12.21	13.43	10.8	7.55	4.85	1.47	2.05	4.96	6.21	6.52	7.26
10.53	10.51	10.53	12.09	12.26	8.81	7.35	2.17	2.41	5.51	5.46	5.51	6.69
12.14	11.99	12.07	12.88	12.45	5.63	4.82	3.17	2.65	2.84	3.29	7.38	6.66
11.94	11.8	11.25	11.8	10.32	6.92	4.68	1.71	4.3	4.03	5.66	8.21	9.72
9.27	9.65	9.98	13.12	11.78	8.64	5.3	3.19	5.94	5.76	7.14	8.62	9.94
12.3	12.09	13.52	12.26	9.55	8.74	5.11	2.24	1.31	4.42	6.62	6.33	7.02
12.66	12.14	11.18	12.54	11.21	10.05	6.4	5.54	3.89	4.49	4.63	6.37	5.8
11.9	11.71	12.73	12.92	10.35	9.17	5.51	2.79	3.01	6.14	7.48	7.31	8.26
10.25	11.56	11.18	12.04	11.83	6.95	4.68	1.69	4.87	5.06	7.4	7.16	7.45
9.29	9.39	9.1	8.55	11.99	8.03	6.8	4.37	2.57	4.92	5.83	7.02	9.05
10.96	10.92	12.02	11.54	11.73	6.64	4.92	3.1	4.49	4.17	5.99	7.9	8.62
10.42	10.56	10.58	10.68	10.82	8.19	4.75	2.03	4.87	4.39	6.71	7.88	8.41
11.23	11.16	10.51	11.66	10.46	8.38	6.76	2.19	2.05	6.09	6.8	6.9	5.42
11.06	11.28	11.23	11.71	9.87	7.76	5.66	5.18	3.46	2.29	4.25	5.56	5.92
10.94	9.89	8.74	7.64	8.96	9.53	6.78	5.18	2.03	4.51	5.28	6.64	9.12
10.75	11.06	10.65	10.53	9.22	8.31	7.12	2.53	2.26	4.96	5.54	7.67	7.57
9.79	9.62	9.94	11.73	10.99	7.81	5.23	2.26	4.7	5.59	7.14	8.76	9.29
11.9	12.14	14.81	13.78	11.35	9.34	7.74	2.48	2.6	4.32	5.87	6.76	7.5
11.92	11.97	11.16	12.78	13.02	11.59	9.84	7.74	5.97	2.96	3.62	5.54	5.42
12.07	11.85	12.66	12.69	11.32	9.24	5.78	4.63	3.05	3.6	5.01	5.94	7.35
11.99	12.47	14.31	12.95	10.8	8.43	6.19	2.84	2.31	1.38	4.8	5.44	5.16

5-Nov-04	6.14	7.35	6.4	4.44	1.95	2.29	5.37	8.26	9.44	10.65	10.78
6-Nov-04	7.93	7.71	7.9	8.62	5.87	2.26	4.42	9.51	12.14	12.78	13.28
7-Nov-04	8.38	7.21	8.6	8.5	6.73	2.62	3.6	7.62	10.63	11.44	12.14
8-Nov-04	8.6	8.6	9.46	9.29	6.97	2.41	1.24	4.87	9.79	11.37	12.07
9-Nov-04	8.24	9.53	8.29	8.79	4.75	2.24	1.52	4.1	9.51	11.66	11.42
10-Nov-04	7.14	6.19	4.94	5.71	5.94	2.41	2.98	7.67	8.86	10.39	11.08
11-Nov-04	7.55	8.26	10.94	10.58	7.67	3.77	1.74	5.59	9.82	11.71	11.28
12-Nov-04	9.89	12.35	12.26	11.3	9.41	5.56	2.55	4.94	7.05	8.03	9.44
13-Nov-04	5.92	8.69	9.62	9.1	6.73	3.53	3.31	7.33	9.05	11.01	11.66
14-Nov-04	6.49	7.64	7.71	8.72	6.35	4.05	2.53	8.19	11.3	12.97	14
15-Nov-04	6.52	8.64	9.41	7.71	5.94	3.19	3.29	7.55	10.75	10.94	10.82
16-Nov-04	7.48	4.96	4.15	3.82	0.8	2.41	9.32	14.53	13.38	12.59	12.78
17-Nov-04	8.24	7.07	4.51	6.3	4.22	2.55	6.52	9.44	12.14	14.67	14.89
18-Nov-04	6.59	6.59	6.4	6.64	6.14	5.39	4.1	1.64	3.41	8.12	10.46
19-Nov-04	8.53	9.53	9.15	8.36	6.64	2.57	3.17	9.44	10.94	11.83	11.23
20-Nov-04	8.46	9.77	8.81	7.62	3.94	1.83	3.22	4.99	7.93	11.83	12.23
21-Nov-04	9.24	9.75	9.6	8.53	6.71	4.1	2.29	5.97	9.75	12.69	12.88
22-Nov-04	5.51	6.14	6.69	6.9	5.63	3.82	3.29	7.45	12.69	13.21	12.57
23-Nov-04	6.95	7.43	8.07	8.57	6.35	4.34	1.81	5.54	9.94	10.65	11.51
24-Nov-04	9.72	10.56	11.08	11.61	9.48	6.28	2.46	2.07	4.96	8.72	9.12
25-Nov-04	10.73	10.96	11.42	10.87	7.4	3.24	1.52	2.07	7.76	8.43	9.77
26-Nov-04	9.15	10.37	10.51	10.32	7.48	3.46	2.1	5.39	8.74	9.67	10.2
27-Nov-04	10.37	10.75	11.51	9.72	2.93	3.6	5.94	7.93	9.08	10.01	12.57
28-Nov-04	9.44	6.16	4.89	5.35	5.8	6.95	6.26	7.88	6.9	5.16	4.34
29-Nov-04	2.48	3.62	5.94	6.06	7.6	7.86	8.74	11.16	11.37	10.8	7.38
30-Nov-04	2.19	3.98	5.08	6.54	7.45	7.93	6.85	7.93	9.12	9.82	6.06
1-Dec-04	3.39	2.93	5.49	5.18	5.61	8.12	7.98	8.79	10.78	9.1	6.42
2-Dec-04	5.97	2.72	4.6	6.04	7.28	8.41	8.89	8.5	8.14	8.62	5.56
3-Dec-04	7.09	3.03	2.76	5.08	5.9	7	8.79	9.72	9.51	9.32	6.54
4-Dec-04	3.72	3.12	2.84	4.6	4.85	6.02	6.52	7.57	8.64	7.57	4.7
5-Dec-04	4.68	2.21	4.37	4.51	6.21	6.62	7.78	6.52	6.06	5.54	5.92
6-Dec-04	4.32	2.93	4.94	5.61	6.85	8.07	8.07	7.19	7.88	8.81	7.09
7-Dec-04	4.34	3.44	4.75	4.53	5.97	8.05	7.02	5.49	5.49	6.78	5.51
8-Dec-04	6.3	3.84	4.73	4.73	5.25	6.45	6.57	6.83	7.98	7.4	3.96
9-Dec-04	5.71	2.03	2.03	3.24	4.58	5.28	6.19	7.52	7.76	5.54	2.38
10-Dec-04	4.96	1.9	4.85	5.35	7.14	8.03	9.01	8.76	10.44	8.98	6.73
11-Dec-04	5.3	4.82	5.49	4.87	5.32	7.83	7.62	9.29	10.68	11.21	8.89
12-Dec-04	3.6	1.33	5.56	5.35	6.97	8.17	9.44	10.15	10.25	10.15	8.98
13-Dec-04	1.28	1.67	4.42	6.19	7.14	8.26	7.93	6.09	6.37	8.24	6.09
14-Dec-04	1.45	2.26	4.1	1.12	2.81	5.73	6.92	6.52	5.83	6.85	5.2
15-Dec-04	2.65	0.85	2.19	5.51	6.66	5.99	5.46	5.37	5.8	5.32	5.28
16-Dec-04	7.38	6.54	3.94	3.12	2.53	3.89	7.64	6.64	6.19	5.8	4.77
17-Dec-04	3.87	4.44	1.76	2.24	5.8	5.2	5.56	5.25	5.01	6.19	5.23
18-Dec-04	5.8	3.15	3.31	4.39	5.28	6.95	7.6	7.31	7.14	7.86	6.3
19-Dec-04	3.08	1.38	3.31	5.42	6.23	7.88	7.78	7.62	9.44	8.74	5.51
20-Dec-04	8.46	5.63	3.24	2.76	3.27	6.02	6.76	7.33	8	7.55	4.92
21-Dec-04	5.61	2.81	1.74	4.34	4.13	4.6	5.39	4.87	6.11	7.07	4.6
22-Dec-04	6.49	3.79	3.84	4.75	3.48	3.24	4.08	4.87	5.35	5.46	4.13
23-Dec-04	5.8	5.68	4.7	2.48	3.01	2.79	4.77	5.08	5.68	6.3	5.54
24-Dec-04	1.88	1.07	4.37	5.66	6.26	5.71	5.37	4.42	4.13	3.89	3.79
25-Dec-04	4.03	2.41	1	4.42	4.77	5.61	6.4	7.02	7.38	6.9	5.01
26-Dec-04	7.67	6.04	2.41	2.26	2.89	4.85	6.4	6.73	5.23	2.6	0.83
27-Dec-04	7.81	5.08	2.05	2.38	3.03	3.82	4.27	4.37	5.03	5.11	3.7
28-Dec-04	6.37	5.71	4.2	2.1	3.27	3.67	4.49	5.76	7.21	6.35	4.73
29-Dec-04	4.08	1.74	2.86	2.21	3.65	4.87	5.76	6.45	7.33	8.53	5.83
30-Dec-04	5.9	2.33	2.5	4.08	5.11	5.54	6.9	6.35	6.28	7.16	5.49

10.73	11.85	12.42	11.13	7.98	6.54	3.55	2.81	4.63	5.87	7	8.76	8.26
12.85	12.59	12.47	11.73	10.35	7.88	6.11	2.31	2.79	4.2	5.39	6.52	7.52
11.66	12.16	11.51	10.58	7.33	8.1	9.27	6.73	2.84	4.03	5.32	5.46	7.12
12.47	13	11.85	13.76	13.05	10.99	7.98	4.82	3.15	4.51	4.85	7.31	8.26
11.54	12.19	13.69	14.67	11.92	8.55	6.33	4.05	2.62	5.01	5.68	5.83	6.76
10.53	11.64	11.61	11.21	11.04	9.29	7.38	1.9	3.91	5.28	6.06	7.43	7.16
10.8	11.01	10.78	13.16	11.23	8.5	4.77	1.95	4.7	5.11	5.66	7.05	9.17
10.89	11.75	11.73	13.48	12.78	9.65	7.67	5.46	2.29	2.43	3.53	7.35	7.57
11.83	12.95	13	11.42	10.35	9.65	7.26	5.23	3.24	3.39	2.93	4.51	7.24
13.71	14.05	12.88	11.23	8.89	8.21	9.32	6.92	7.35	4.2	3.15	4.63	5.16
11.23	11.73	11.59	11.08	10.27	9.7	7.95	7.98	6.66	4.94	2.26	4.03	5.71
11.85	10.8	9.75	8.46	7.62	8.84	6.52	4.56	3.08	3.84	4.46	7.26	8.31
11.94	11.54	10.82	14.62	12.09	11.97	8.38	4.92	3.91	3.82	4.85	4.37	5.42
10.15	9.7	8.41	10.44	12.21	8.46	6.69	3.03	1.95	4.22	3.12	6.02	8.38
11.28	12.07	12.23	13.05	9.12	6.45	4.96	2.89	3.98	4.87	4.25	5.35	7.78
11.54	11.75	12.21	12.42	13.19	11.08	8.76	5.03	2.53	1.57	3.53	6.23	7.64
12.64	12.59	11.06	10.61	10.35	10.13	7.07	8.07	6.49	1.93	4.17	4.2	5.2
12.95	12.23	10.82	11.04	9.65	7.98	8.07	7.35	4.51	5.01	4.37	4.85	6.42
11.73	11.9	11.42	10.3	9.24	10.89	7.64	2.81	3.7	5.37	5.92	7.55	8.64
9.77	10.18	10.08	10.56	12.37	9.51	6.26	2.43	4.17	6.21	6.95	8.86	9.51
9.82	9.87	9.22	10.96	10.82	9.08	5.99	2.26	2.38	5.16	6.78	7.62	8.64
11.25	11.61	12.07	12.14	11.78	10.01	6.64	2.62	2.36	5.16	5.87	8.17	8.96
2.26	1.6	5.51	8.98	11.23	12.59	12.4	13.09	12.64	11.61	9.65	10.2	12.16
2.65	6.28	9.67	11.78	11.32	12.33	11.18	9.65	11.68	9.36	8.26	7.12	5.03
4.63	2.86	1.78	6.69	11.23	11.73	12.09	12.09	13.74	13.78	10.65	8.36	4.96
2.36	3.58	8.1	10.89	11.97	12.83	12.78	12.57	12.3	13.35	11.25	9.22	5.83
2.38	1.38	5.13	9.55	12.28	12.49	12.73	12.73	14.86	14.05	10.22	8.96	5.99
2.26	7.38	10.46	10.99	12.09	12.16	11.9	10.78	11.49	12.66	10.32	9.55	8.69
2.38	2.48	7.67	10.27	11.47	11.59	11.06	11.04	12.62	12.04	10.08	8.36	5.51
1.57	2.69	6.62	9.67	11.54	12.26	12.09	12.76	13.19	12.49	10.37	9.22	6.47
2.29	2.17	6.64	10.05	12.09	12.97	13.19	13.38	14.43	13.48	10.85	8.98	6.06
3.46	2.74	9.48	11.49	12.42	13.55	13.38	13	13.69	13.95	12.09	9.27	6.62
2.48	2.57	7.16	10.61	12.26	12.59	11.64	11.35	11.08	11.83	9.62	10.78	7.48
1.4	5.13	8.07	9.39	10.49	11.35	11.35	11.08	10.42	10.94	12.62	10.25	8.67
0.83	3.62	7.33	9.24	10.44	11.61	11.78	10.63	11.3	11.44	8.69	9.62	9.32
3.36	1.64	5.63	9.44	11.56	12.21	11.99	13.05	12.33	11.16	7.88	7.38	6.62
5.35	2.48	2.89	7	8.62	8.67	9.79	9.96	9.96	11.83	12.83	10.46	6.92
5.73	2.79	5.03	10.32	12.11	11.97	12.4	12.59	14.12	12.33	10.73	9.29	6.04
2.26	2.24	8.17	12.11	13.38	13.57	13.48	13.74	12.73	9.53	8.55	7.86	4.17
2.17	5.61	9.08	12.09	13.64	14.24	13.83	12.47	12.16	11.13	9.05	9.12	6.19
3.24	4.01	7.95	11.44	12.76	11.75	11.3	10.85	11.28	11.99	11.11	10.58	9.72
2	2.86	8.03	10.75	12.14	12.66	12.21	11.97	11.3	10.99	11.59	9.51	7.5
1.74	4.34	8.67	10.89	12.26	13.28	13.78	13.38	14.29	14.17	10.25	9.51	7.35
2.43	2.07	6.26	9.82	10.82	11.44	11.97	12.26	13.88	13.57	11.71	9.55	6.64
2	2.43	4.92	8.31	9.1	10.08	11.3	12.04	11.78	10.39	12.78	12.42	10.53
2.98	1.9	2.84	7.09	9.24	11.08	11.16	11.83	12.88	15.15	12.4	9.89	6.88
1.78	2.1	3.19	5.51	8.76	9.82	10.89	11.59	12.76	13.57	12.02	10.22	9.53
1.64	1.31	5.63	9.34	11.39	11.94	11.59	11.16	12.4	13.55	11.16	9.89	7.81
3.77	1.6	0.78	4.89	8.96	11.54	11.44	10.73	12.07	11.35	11.68	9.89	6.73
2.26	4.03	6.47	10.1	12.54	12.26	12.04	13.21	13.91	12.76	11.08	8.05	7.05
2.19	2.36	7.55	11.73	12.85	14.07	14.14	13.67	12.37	11.61	9.19	7.24	8.76
4.53	6.64	8.91	10.42	12.52	13.6	14	13.67	12.97	10.44	8.41	10.13	9.98
2.33	1.64	4.75	7.78	9.29	11.23	11.16	11.13	11.49	12.04	13.74	10.46	7.71
2.19	1.64	3.91	7.16	9.96	11.64	11.44	11.3	11.71	11.66	11.18	9.39	7.4
3.12	2.03	3.51	8.31	10.49	11.92	12.02	11.85	12.64	12.26	11.39	10.3	9.03
2.91	1.67	4.96	10.78	11.97	11.35	11.54	10.61	11.39	11.11	11.71	11.08	7.76

Appendix C. FIRM CAPACITY CALCULATION

The firm capacity of a power plant is determined by the following calculation procedure:

1. Calculate the Initial Power for each power plant.
2. Preliminary Firm Capacity calculation for each power plant.
3. Firm Capacity calculation.

1. Initial Power

The initial power of a power plant is the amount of power that this plant is able to deliver to the system including the variability of the resource or fuel the power plant uses. Generally the initial power is taken form historical data. The standard way of calculating the initial power is to take the average of maximum power from the histogram of generation.

2. Preliminary Firm Capacity

For the preliminary firm capacity there are two ways of calculating it. One is focused mainly on thermal generation and the other on other technologies that differ from thermal generation, this could be technologies like hydro or some renewable energy technologies like wind energy.

a. Thermal Technologies

The methodology for calculating the preliminary firm capacity in the SING for thermal power plants is conformed by three separated calculations with the purpose of being able to quantify the sufficiency and security of the electrical system. The first calculation is the contribution that each generating plant does to the system's sufficiency and is called "*Sufficiency Calculation*". The second and third are focused on quantifying the contribution of each plant to the system's security. These calculations are called *"Starting Time Calculation"* and *"Load Increase Time Calculation"*. Therefore, the Preliminary Firm Capacity is defined as the following equation shows.

$$PFP_i = \frac{1}{2} SP_i + \frac{1}{4} ST_i + \frac{1}{4} LIT_i \tag{6.5}$$

where,

$PFP_i =$ *Preliminary Firm Power 'i'.*

$SP_i =$ *Sufficiency Power calculation 'i'*

$ST_i =$ *Starting Time Power for 'i'*

$LIT_i =$ *Load Increase Time Power for 'i'*

- ***Sufficiency Firm Capacity:***

Taking the Initial Power (IP) discounting the plant own consumptions and forced unavailability is possible to calculate the Sufficiency Firm Capacity.

$$SP_i = IP_i \times \left(1 - C_{own}\right)_i \times \left(1 - U\right)_i \times \frac{1 - LOLP_{peak}^{i}}{1 - LOLP_{peak}} \tag{6.6}$$

where,

$IP_i =$ *Initial Power of 'i'*

$C_{own} =$ *Plant Own Consumptions Ratio*

U= *Plant Unavailability Ratio*

$LOLP_{peak}^{i} =$ *Lost of load probability without 'i' at peak*

$LOLP_{peak} =$ *Lost of load probability including 'i' at peak*

For the last equation is necessary to calculate the unavailability ratio which can be obtained from the following equation:

$$U = \left[\frac{T_{OFF}}{T_{ON} + T_{OFF}} \right] \tag{6.7}$$

- ***Starting Time Power:***

In this case a level of importance is assigned to the variable "starting time" for each power plant. The assignment is done through a factor, which will be called F_T. Specifically, for a 5 hour window, each plant is evaluated to measure its ability to start generating.

$$ST_i = IP_i \times (1 - C_{own}) \times F_T \tag{6.8}$$

The factor F_T is calculated with the following expressions including the start time T_{start}:

$$F_T = \begin{cases} 1 - \dfrac{T_{start}}{10} & ; T_{start} \leq 5 \ hours \\ \dfrac{5}{2 \cdot T_{start}} & ; T_{start} > 5 \ hours \end{cases} \tag{6.9}$$

- ***Load Increase Time Power:***

In this case a level of importance is assigned to the variable "Load Increase Time" for each power plant. The assignment is done through a factor, which will be called F_I. Specifically, for a 5 hour window, each plant is evaluated to measure its ability to start generating.

$$ST_i = IP_i \times (1 - C_{own}) \times F_I \tag{6.10}$$

The factor F_I is calculated with the following expressions including the start time $T_{increase}$:

$$F_I = \begin{cases} 1 - \dfrac{T_{increase}}{10} & ; T_{start} \leq 5 \ hours \\ \dfrac{5}{2 \cdot T_{increase}} & ; T_{start} > 5 \ hours \end{cases} \tag{6.11}$$

b. Other Technologies

For other technologies the calculation of the preliminary firm capacity simplifies to the calculation of the sufficiency power calculation shown earlier on equation(6.6).

3. Firm Capacity Calculation

Hence, to obtain the firm capacity, the preliminary firm capacity is adapted through a factor that is the division between the system's maximum demand and the sum of the preliminary firm capacity for all the other power plants.

$$FP_i = PFP_i \times \left[\frac{D_{\max}}{\sum_j PFP_j} \right] \tag{6.12}$$

After this calculation, may be necessary to lower the value of the firm capacity owing to transmission capacity of the system or subsystem surrounding a specific power plant, this can be achieved through a correction factor which multiplies the firm capacity on equation (6.12) to obtain the final firm capacity.

Appendix D. POWER CURVE DATA

Here is the data used for constructing the power curve that estimates the amount of power the turbine is capable of generating at the air density of the site on evaluation.

CURVE @ 1.225[kg/m3]	
Wind Speed (m/s)	Power (kW)
0.0	0
0.5	0
1.0	0
1.5	0
2.0	0
2.5	0
3.0	0
3.5	10
4.0	25
4.5	62
5.0	120
5.5	180
6.0	260
6.5	370
7.0	500
7.5	650
8.0	820
8.5	1000
9.0	1150
9.5	1300
10.0	1400
10.5	1480
11.0	1560
11.5	1600
12.0	1620
12.5	1635
13.0	1650
13.5	1650
14.0	1650
14.5	1650
15.0	1650
15.5	1650
16.0	1650
16.5	1650
17.0	1650
17.5	1650
18.0	1650
18.5	1650
19.0	1650
19.5	1650
20.0	1650

Figure 5-2: Original Power Curve Data (1.225[kg/m3])

Wind Power (kW)	Wind Speed (m/s)	Cp		Power (kW)
0.0	0.0	0.00		0.0
0.3	0.5	0.00		0.0
2.5	1.0	0.00		0.0
8.5	1.5	0.00		0.0
20.1	2.0	0.00		0.0
39.2	2.5	0.00		0.0
67.7	3.0	0.00		0.0
107.6	3.5	0.05		5.0
160.5	4.0	0.11		17.0
228.6	4.5	0.26		60.0
313.6	5.0	0.40		125.0
417.3	5.5	0.43		180.0
541.8	6.0	0.44		240.0
688.9	6.5	0.45		310.0
860.4	7.0	0.46		395.0
1058.3	7.5	0.46		490.0
1284.3	8.0	0.46		590.0
1540.5	8.5	0.45		700.0
1828.7	9.0	0.45		815.0
2150.7	9.5	0.43		930.0
2508.5	10.0	0.41		1025.0
2903.9	10.5	0.39		1130.0
3338.8	11.0	0.37		1230.0
3815.1	11.5	0.34		1290.0
4334.7	12.0	0.30		1320.0
4899.4	12.5	0.27		1330.0
5511.1	13.0	0.24		1350.0
6171.8	13.5	0.22		1350.0
6883.3	14.0	0.20		1350.0
7647.4	14.5	0.18		1350.0
8466.1	15.0	0.16		1350.0
9341.3	15.5	0.14		1350.0
10274.7	16.0	0.13		1350.0
11268.4	16.5	0.12		1350.0
12324.2	17.0	0.11		1350.0
13443.9	17.5	0.10		1350.0
14629.5	18.0	0.09		1350.0
15882.8	18.5	0.08		1350.0
17205.7	19.0	0.08		1350.0
18600.1	19.5	0.07		1350.0
20067.8	20.0	0.07		1350.0

Figure 5-3: New Power Curve Data (0.95[kg/m3])

Appendix E. CONTRACT PRICES

	10%	11%	12%
Case 1	$ 114.09	$ 122.18	$ 130.46
Case 2	$ 114.09	$ 122.18	$ 130.46
Case 3	$ 114.09	$ 122.18	$ 130.46
Case 4	$ 112.22	$ 120.18	$ 128.32
Case 5	$ 112.22	$ 120.18	$ 128.32
Case 6	$ 112.22	$ 120.18	$ 128.32
Case 7	$ 110.65	$ 118.49	$ 126.52
Case 8	$ 110.65	$ 118.49	$ 126.52
Case 9	$ 110.65	$ 118.49	$ 126.52
Case 10	$ 114.09	$ 122.18	$ 130.46
Case 11	$ 114.09	$ 122.18	$ 130.46
Case 12	$ 114.09	$ 122.18	$ 130.46
Case 13	$ 112.22	$ 120.18	$ 128.32
Case 14	$ 112.22	$ 120.18	$ 128.32
Case 15	$ 112.22	$ 120.18	$ 128.32
Case 16	$ 110.65	$ 118.49	$ 126.52
Case 17	$ 110.65	$ 118.49	$ 126.52
Case 18	$ 110.65	$ 118.49	$ 126.52

Figure 5-4: Contract Prices for No Firm Capacity and Unregistered Project

	10%	11%	12%
Case 1	$ 98.02	$ 106.11	$ 114.38
Case 2	$ 98.04	$ 106.13	$ 114.41
Case 3	$ 98.03	$ 106.12	$ 114.40
Case 4	$ 96.38	$ 104.34	$ 112.48
Case 5	$ 96.43	$ 104.38	$ 112.52
Case 6	$ 96.42	$ 104.38	$ 112.52
Case 7	$ 95.42	$ 103.27	$ 111.29
Case 8	$ 95.49	$ 103.34	$ 111.37
Case 9	$ 95.47	$ 103.32	$ 111.34
Case 10	$ 96.77	$ 104.86	$ 113.14
Case 11	$ 96.82	$ 104.90	$ 113.18
Case 12	$ 96.81	$ 104.89	$ 113.17
Case 13	$ 95.25	$ 103.20	$ 111.34
Case 14	$ 95.32	$ 103.28	$ 111.41
Case 15	$ 95.31	$ 103.26	$ 111.40
Case 16	$ 94.24	$ 102.09	$ 110.12
Case 17	$ 94.36	$ 102.21	$ 110.23
Case 18	$ 94.35	$ 102.19	$ 110.22

Figure 5-5: Contract Prices for Firm Capacity and Unregistered Project

	10%	11%	12%
Case 1	$ 92.30	$ 100.39	$ 108.66
Case 2	$ 92.32	$ 100.41	$ 108.68
Case 3	$ 92.31	$ 100.40	$ 108.67
Case 4	$ 90.65	$ 98.61	$ 106.75
Case 5	$ 90.70	$ 98.65	$ 106.79
Case 6	$ 90.69	$ 98.65	$ 106.79
Case 7	$ 89.68	$ 97.53	$ 105.55
Case 8	$ 89.75	$ 97.60	$ 105.63
Case 9	$ 89.73	$ 97.58	$ 105.60
Case 10	$ 91.05	$ 99.14	$ 107.41
Case 11	$ 91.09	$ 99.18	$ 107.46
Case 12	$ 91.08	$ 99.17	$ 107.45
Case 13	$ 89.52	$ 97.47	$ 105.61
Case 14	$ 89.59	$ 97.55	$ 105.69
Case 15	$ 89.58	$ 97.53	$ 105.67
Case 16	$ 88.50	$ 96.35	$ 104.38
Case 17	$ 88.62	$ 96.47	$ 104.49
Case 18	$ 88.61	$ 96.45	$ 104.48

Figure 5-6: Contract Prices for Firm Capacity and Registered Project

	10%	11%	12%
Case 1	$ 108.37	$ 116.46	$ 124.73
Case 2	$ 108.37	$ 116.46	$ 124.73
Case 3	$ 108.37	$ 116.46	$ 124.73
Case 4	$ 106.50	$ 114.45	$ 122.59
Case 5	$ 106.50	$ 114.45	$ 122.59
Case 6	$ 106.50	$ 114.45	$ 122.59
Case 7	$ 104.91	$ 112.75	$ 120.78
Case 8	$ 104.91	$ 112.75	$ 120.78
Case 9	$ 104.91	$ 112.75	$ 120.78
Case 10	$ 108.37	$ 116.46	$ 124.73
Case 11	$ 108.37	$ 116.46	$ 124.73
Case 12	$ 108.37	$ 116.46	$ 124.73
Case 13	$ 106.50	$ 114.45	$ 122.59
Case 14	$ 106.50	$ 114.45	$ 122.59
Case 15	$ 106.50	$ 114.45	$ 122.59
Case 16	$ 104.91	$ 112.75	$ 120.78
Case 17	$ 104.91	$ 112.75	$ 120.78
Case 18	$ 104.91	$ 112.75	$ 120.78

Figure 5-7: Contract Prices for No Firm Capacity and Registered Project

Appendix F. CONSTRUCTION AND INVESTMENT COSTS

Construction and investment cost for a Vestas V.82 1.65MW wind turbine.

Construction Costs

		Wind Farm Capacity [MW]		
		173.25	90.75	57.75
Activity		US$	US$	US$
15kV Underground Power Lines		5,867,600	3,227,600	2,171,600
Transfomer and Turbine Foundations		24,144,300	12,649,300	8,051,300
Low Voltage Electricy Work		453,800	233,800	145,800
Towers and Turbines Installation		24,487,050	12,304,550	7,431,550
Wind Farm Substation		1,665,000	1,665,000	1,665,000
110kV Transmission Line		1,595,000	1,595,000	1,595,000
Roads and Terrain Adequacy		743,700	688,700	666,700
Connection Node Adequacy		316,000	316,000	316,000
Indirect Costs		38,929,300	20,834,300	13,596,300
TOTAL		**98,201,750**	**53,514,250**	**35,639,250**

Hardware Costs

		Wind Farm [MW]		
	One Turbine	173.25	90.75	57.75
ITEMS	US$	US$	US$	US$
Tubine+Tower	1,700,000	178,500,000	93,500,000	59,500,000
Containers (Flatbeds)	45,596	4,787,591	2,507,786	1,595,864
Remote Control System	6,289	660,362	345,904	220,121
Installation Components	31,984	3,358,268	1,759,093	1,119,423
Installation Tools	13,933	1,462,923	766,293	487,641
FOB Value	1,797,801	188,769,143	98,879,075	62,923,048
Freight	1,125,066	118,131,930	61,878,630	39,377,310
CIF Value	2,922,867	306,901,073	160,757,705	102,300,358
Installation Supervision (120 Days)		1,182,426	1,182,426	1,182,426
Maintenance and Service (2 Years)		802,753	802,753	802,753
Total		**308,886,252**	**162,742,884**	**104,285,537**
FOB Value per MW		1,089,577	1,089,577	1,089,577
Freight per MW		681,858	681,858	681,858
CIF per MW		1,771,435	1,771,435	1,771,435
Total per MW		1,782,893	1,793,310	1,805,810

Variable and Fixed Costs				
		Wind Farm [MW]		
		173.25	90.75	57.75
Fixed Costs				
Fixed Operational [US$/year]		362,816.63	191,157.18	122,493.40
Administration and Sales [US$/year]		544,224.95	286,735.77	183,740.10
Fixed Costs Total [US$/year]		**907,041.58**	**477,892.95**	**306,233.50**
Variable Costs				
Operation and Maintenance [US$/MWh]		10	10	10
Variable Costs Total [US$/MWh]		**10**	**10**	**10**

Appendix G. SIMULATION SYSTEM MARGINAL COSTS

1. Non-Adapted System Marginal Costs

	Normal Demand								
	57.75			90.75			173.25		
	O'Higgins 220	Calama 110	Crucero 220	O'Higgins 220	Calama 110	Crucero 220	O'Higgins 220	Calama 110	Crucero 220
	1	2	3	4	5	6	7	8	9
2008	$ 117.90	$ 117.68	$ 117.72	$ 115.35	$ 114.66	$ 115.07	$ 112.23	$ 111.81	$ 111.89
2009	$ 137.91	$ 137.44	$ 137.52	$ 136.82	$ 136.19	$ 136.33	$ 132.79	$ 131.67	$ 131.92
2010	$ 144.09	$ 143.85	$ 143.91	$ 142.03	$ 141.31	$ 141.36	$ 139.68	$ 138.17	$ 138.35
2011	$ 121.07	$ 120.64	$ 120.67	$ 118.73	$ 118.31	$ 118.33	$ 115.47	$ 114.47	$ 114.81
2012	$ 86.76	$ 86.51	$ 86.52	$ 86.42	$ 86.23	$ 86.24	$ 84.15	$ 83.91	$ 84.01
2013	$ 96.04	$ 95.97	$ 95.97	$ 95.73	$ 95.14	$ 95.15	$ 93.92	$ 90.66	$ 90.72
2014	$ 94.38	$ 93.63	$ 93.65	$ 93.74	$ 92.96	$ 92.97	$ 92.74	$ 92.34	$ 92.37
2015	$ 96.69	$ 96.47	$ 96.53	$ 96.66	$ 96.29	$ 96.35	$ 96.24	$ 95.48	$ 95.55
2016	$ 94.98	$ 94.77	$ 94.77	$ 94.54	$ 94.22	$ 94.24	$ 93.64	$ 92.86	$ 93.04
2017	$ 96.75	$ 96.65	$ 96.66	$ 96.67	$ 95.92	$ 95.96	$ 95.93	$ 95.37	$ 95.43
2018	$ 98.28	$ 98.05	$ 98.08	$ 98.03	$ 97.67	$ 97.78	$ 97.81	$ 97.29	$ 97.31
2019	$ 98.28	$ 98.05	$ 98.08	$ 98.03	$ 97.67	$ 97.78	$ 97.81	$ 97.29	$ 97.31
2020	$ 98.28	$ 98.05	$ 98.08	$ 98.03	$ 97.67	$ 97.78	$ 97.81	$ 97.29	$ 97.31
2021	$ 98.28	$ 98.05	$ 98.08	$ 98.03	$ 97.67	$ 97.78	$ 97.81	$ 97.29	$ 97.31
2022	$ 98.28	$ 98.05	$ 98.08	$ 98.03	$ 97.67	$ 97.78	$ 97.81	$ 97.29	$ 97.31

Figure 5-8: Normal Demand System Marginal Costs

	High Demand								
	57.75			90.75			173.25		
	O'Higgins 220	Calama 110	Crucero 220	O'Higgins 220	Calama 110	Crucero 220	O'Higgins 220	Calama 110	Crucero 220
	10	11	12	13	14	15	16	17	18
2008	$ 117.90	$ 117.68	$ 117.72	$ 115.35	$ 114.66	$ 115.07	$ 112.23	$ 111.81	$ 111.89
2009	$ 137.91	$ 137.44	$ 137.52	$ 136.82	$ 136.19	$ 136.33	$ 132.79	$ 131.67	$ 131.92
2010	$ 157.98	$ 157.53	$ 157.68	$ 156.17	$ 155.15	$ 155.45	$ 151.20	$ 149.57	$ 149.88
2011	$ 168.86	$ 166.88	$ 168.44	$ 165.64	$ 164.68	$ 165.17	$ 156.93	$ 154.80	$ 155.54
2012	$ 116.11	$ 115.42	$ 115.54	$ 113.53	$ 112.99	$ 113.42	$ 111.86	$ 111.46	$ 111.50
2013	$ 181.63	$ 180.74	$ 180.86	$ 178.05	$ 176.92	$ 177.18	$ 165.99	$ 164.91	$ 165.08
2014	$ 248.96	$ 247.74	$ 248.73	$ 244.75	$ 242.60	$ 243.60	$ 227.35	$ 224.19	$ 225.16
2015	$ 284.47	$ 284.40	$ 284.45	$ 281.38	$ 279.29	$ 279.62	$ 272.45	$ 269.23	$ 271.66
2016	$ 281.89	$ 280.18	$ 281.45	$ 276.14	$ 273.14	$ 274.76	$ 266.17	$ 263.77	$ 264.86
2017	$ 302.66	$ 303.32	$ 302.52	$ 300.75	$ 301.58	$ 300.51	$ 298.86	$ 298.42	$ 298.56
2018	$ 306.78	$ 306.98	$ 306.70	$ 306.26	$ 306.36	$ 306.11	$ 304.51	$ 303.79	$ 303.53
2019	$ 306.78	$ 306.98	$ 306.70	$ 306.26	$ 306.36	$ 306.11	$ 304.51	$ 303.79	$ 303.53
2020	$ 306.78	$ 306.98	$ 306.70	$ 306.26	$ 306.36	$ 306.11	$ 304.51	$ 303.79	$ 303.53
2021	$ 306.78	$ 306.98	$ 306.70	$ 306.26	$ 306.36	$ 306.11	$ 304.51	$ 303.79	$ 303.53
2022	$ 306.78	$ 306.98	$ 306.70	$ 306.26	$ 306.36	$ 306.11	$ 304.51	$ 303.79	$ 303.53

Figure 5-9: High Demand System Marginal Costs

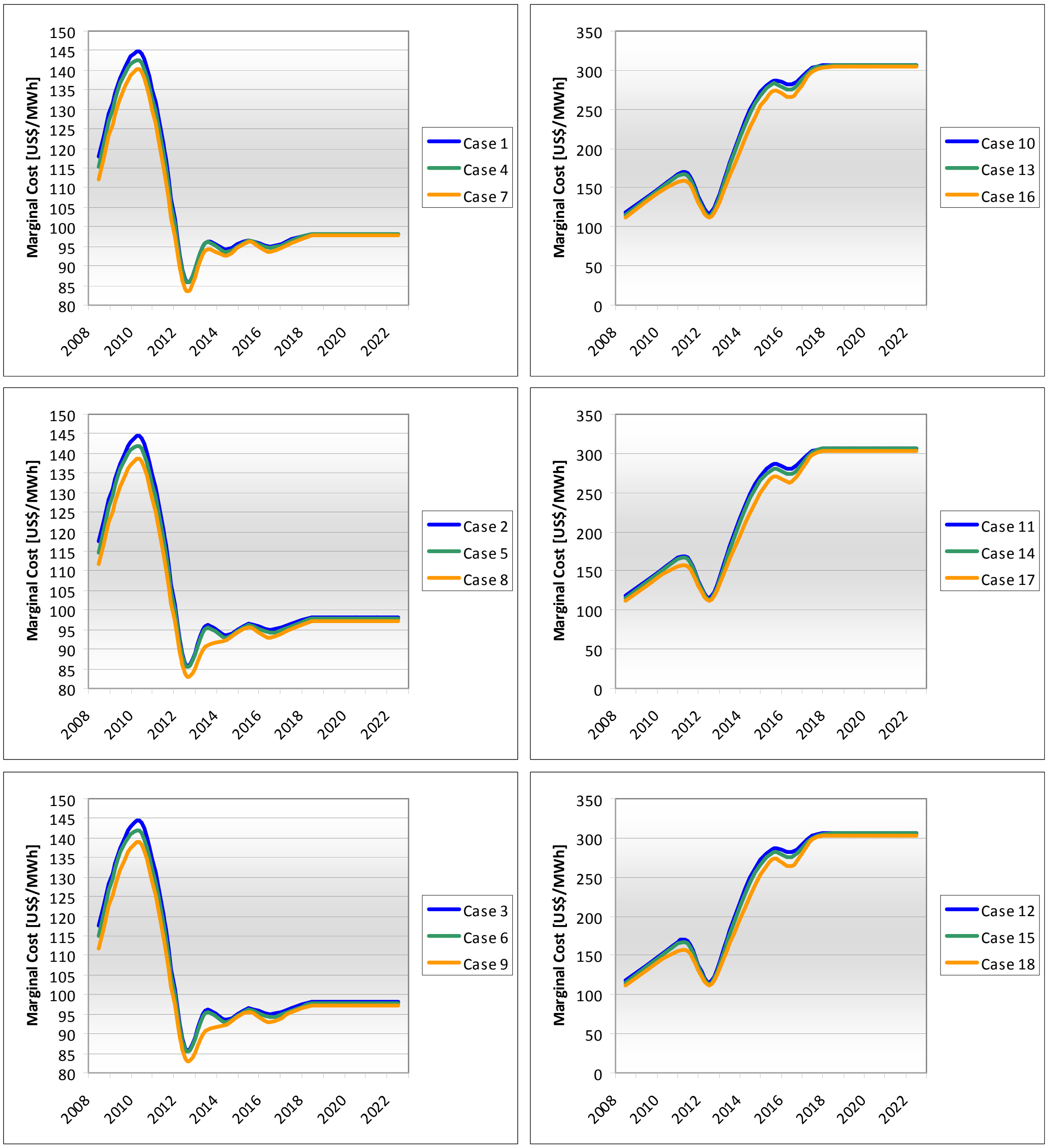

Figure 5-10: System Marginal Cost Behavior for each Case

2. Adapted System Marginal Costs

	Normal Demand								
	57.75			90.75			173.25		
	O'Higgins 220	Calama 110	Crucero 220	O'Higgins 220	Calama 110	Crucero 220	O'Higgins 220	Calama 110	Crucero 220
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9
2008	$ 117.25	$ 117.16	$ 117.13	$ 116.31	$ 116.21	$ 116.19	$ 115.41	$ 115.31	$ 115.29
2009	$ 138.08	$ 137.97	$ 137.94	$ 137.82	$ 137.70	$ 137.67	$ 137.53	$ 137.42	$ 137.39
2010	$ 142.77	$ 142.66	$ 142.63	$ 141.92	$ 141.80	$ 141.77	$ 141.62	$ 141.50	$ 141.47
2011	$ 120.25	$ 120.15	$ 120.12	$ 119.80	$ 119.70	$ 119.68	$ 119.19	$ 119.10	$ 119.07
2012	$ 75.63	$ 75.57	$ 75.55	$ 75.35	$ 75.29	$ 75.28	$ 74.00	$ 73.94	$ 73.92
2013	$ 30.80	$ 30.78	$ 30.77	$ 30.80	$ 30.77	$ 30.77	$ 30.79	$ 30.77	$ 30.76
2014	$ 32.01	$ 31.98	$ 31.97	$ 32.01	$ 31.98	$ 31.97	$ 31.97	$ 31.94	$ 31.94
2015	$ 33.01	$ 32.98	$ 32.97	$ 32.99	$ 32.97	$ 32.96	$ 32.99	$ 32.96	$ 32.96
2016	$ 32.44	$ 32.41	$ 32.41	$ 32.43	$ 32.40	$ 32.40	$ 32.43	$ 32.40	$ 32.40
2017	$ 34.91	$ 34.88	$ 34.87	$ 34.91	$ 34.88	$ 34.87	$ 34.89	$ 34.87	$ 34.86
2018	$ 35.31	$ 35.29	$ 35.28	$ 35.31	$ 35.28	$ 35.28	$ 35.30	$ 35.27	$ 35.26
2019	$ 35.31	$ 35.29	$ 35.28	$ 35.31	$ 35.28	$ 35.28	$ 35.30	$ 35.27	$ 35.26
2020	$ 35.31	$ 35.29	$ 35.28	$ 35.31	$ 35.28	$ 35.28	$ 35.30	$ 35.27	$ 35.26
2021	$ 35.31	$ 35.29	$ 35.28	$ 35.31	$ 35.28	$ 35.28	$ 35.30	$ 35.27	$ 35.26
2022	$ 35.31	$ 35.29	$ 35.28	$ 35.31	$ 35.28	$ 35.28	$ 35.30	$ 35.27	$ 35.26

Figure 5-11: Normal Demand System Marginal Costs

	High Demand								
	57.75			90.75			173.25		
	O'Higgins 220	Calama 110	Crucero 220	O'Higgins 220	Calama 110	Crucero 220	O'Higgins 220	Calama 110	Crucero 220
	Case 10	Case 11	Case 12	Case 13	Case 14	Case 15	Case 16	Case 17	Case 18
2008	$ 117.25	$ 117.16	$ 117.13	$ 116.31	$ 116.21	$ 116.19	$ 115.41	$ 115.31	$ 115.29
2009	$ 138.08	$ 137.97	$ 137.94	$ 137.82	$ 137.70	$ 137.67	$ 137.53	$ 137.42	$ 137.39
2010	$ 158.93	$ 158.80	$ 158.77	$ 157.98	$ 157.85	$ 157.82	$ 157.65	$ 157.52	$ 157.49
2011	$ 169.63	$ 169.49	$ 169.46	$ 169.01	$ 168.87	$ 168.83	$ 168.15	$ 168.01	$ 167.97
2012	$ 95.63	$ 95.56	$ 95.54	$ 95.28	$ 95.20	$ 95.18	$ 93.57	$ 93.49	$ 93.47
2013	$ 84.25	$ 84.18	$ 84.16	$ 84.24	$ 84.17	$ 84.15	$ 84.23	$ 84.16	$ 84.14
2014	$ 92.47	$ 92.39	$ 92.37	$ 92.47	$ 92.39	$ 92.37	$ 92.36	$ 92.28	$ 92.27
2015	$ 99.59	$ 99.51	$ 99.49	$ 99.55	$ 99.47	$ 99.45	$ 99.54	$ 99.46	$ 99.44
2016	$ 98.61	$ 98.53	$ 98.51	$ 98.57	$ 98.49	$ 98.47	$ 98.57	$ 98.50	$ 98.48
2017	$ 103.03	$ 102.95	$ 102.93	$ 103.03	$ 102.95	$ 102.93	$ 102.99	$ 102.91	$ 102.89
2018	$ 108.39	$ 108.31	$ 108.28	$ 108.38	$ 108.29	$ 108.27	$ 108.34	$ 108.25	$ 108.23
2019	$ 108.39	$ 108.31	$ 108.28	$ 108.38	$ 108.29	$ 108.27	$ 108.34	$ 108.25	$ 108.23
2020	$ 108.39	$ 108.31	$ 108.28	$ 108.38	$ 108.29	$ 108.27	$ 108.34	$ 108.25	$ 108.23
2021	$ 108.39	$ 108.31	$ 108.28	$ 108.38	$ 108.29	$ 108.27	$ 108.34	$ 108.25	$ 108.23
2022	$ 108.39	$ 108.31	$ 108.28	$ 108.38	$ 108.29	$ 108.27	$ 108.34	$ 108.25	$ 108.23

Figure 5-12: High Demand System Marginal Costs

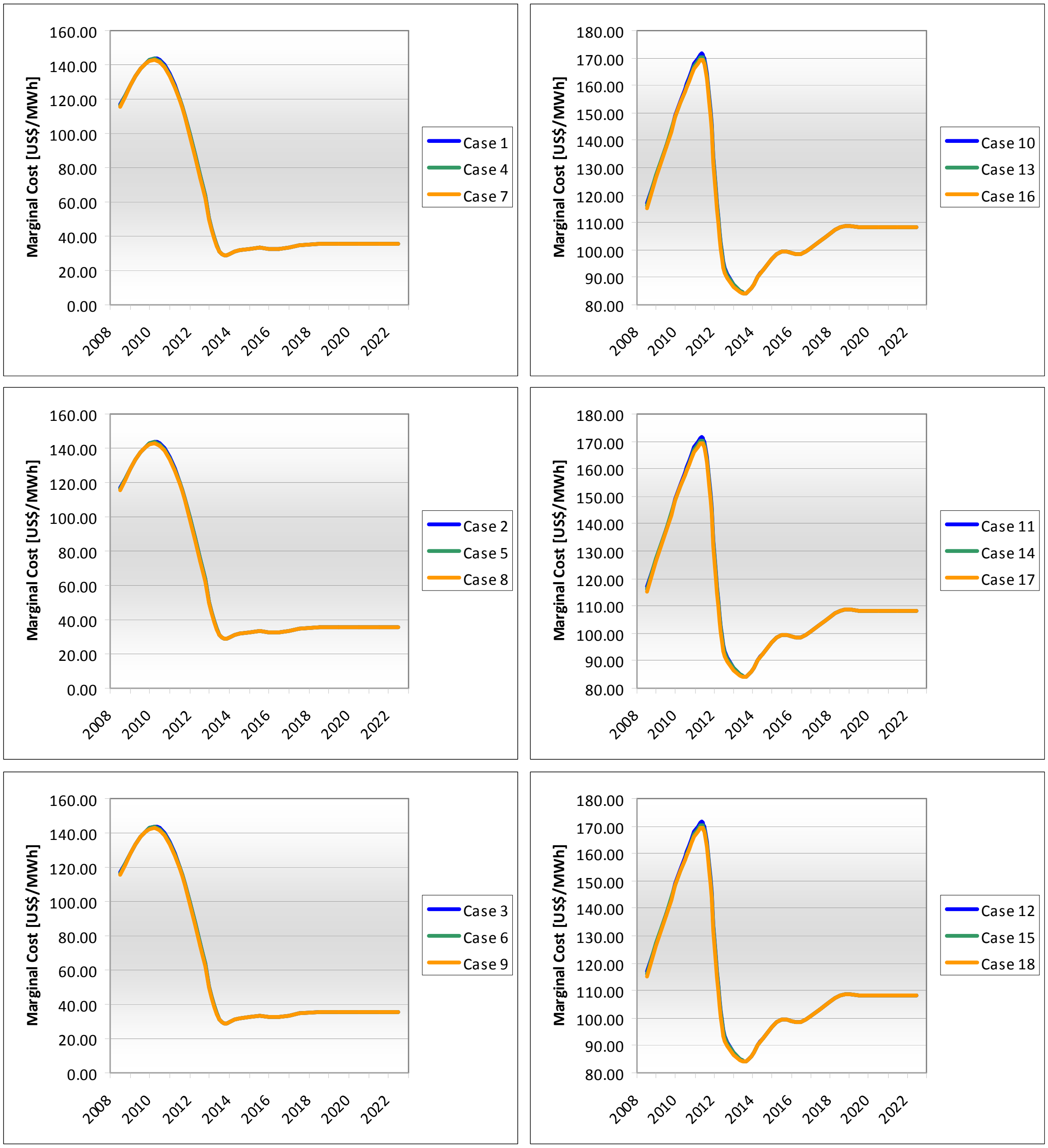

Figure 5-13: System Marginal Cost Behavior for each Case

Appendix H. NPV PER CASE (NON-ADAPTED SYSTEM)

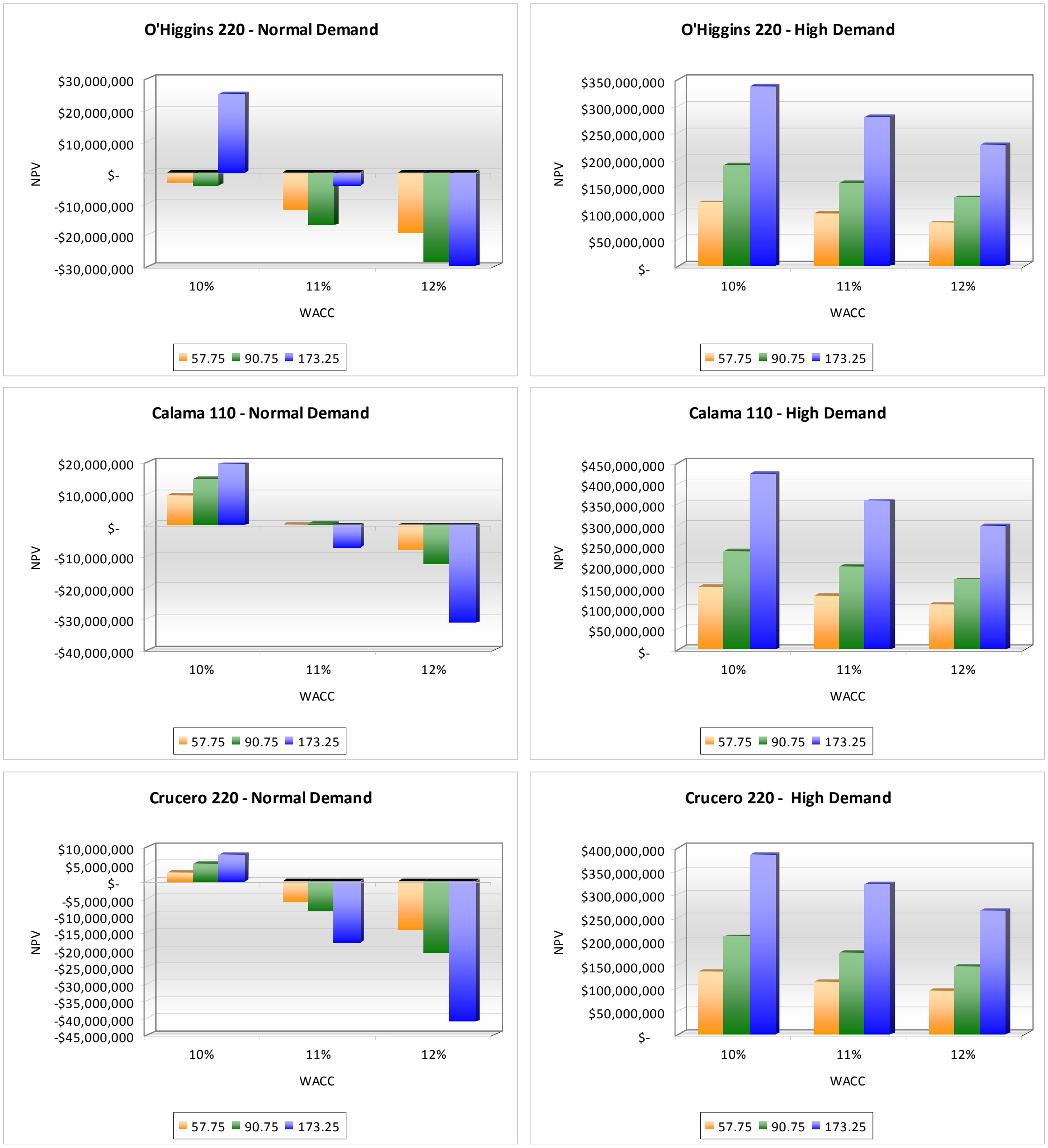

Figure 5-14: NPV for No Firm Capacity, No Contract and Unregistered CDM Project

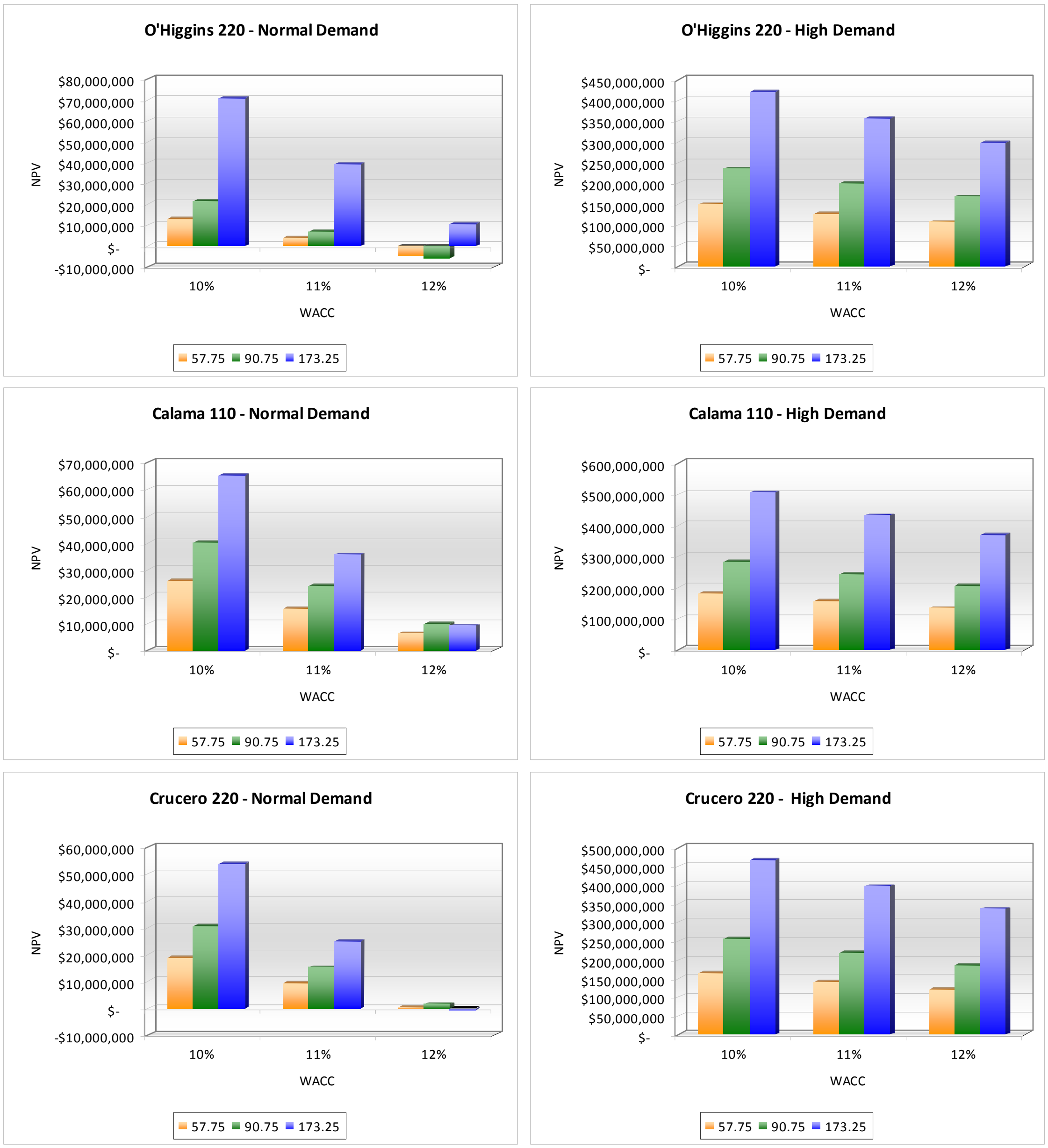

Figure 5-15: NPV for Firm Capacity, No Contract and Unregistered CDM Project

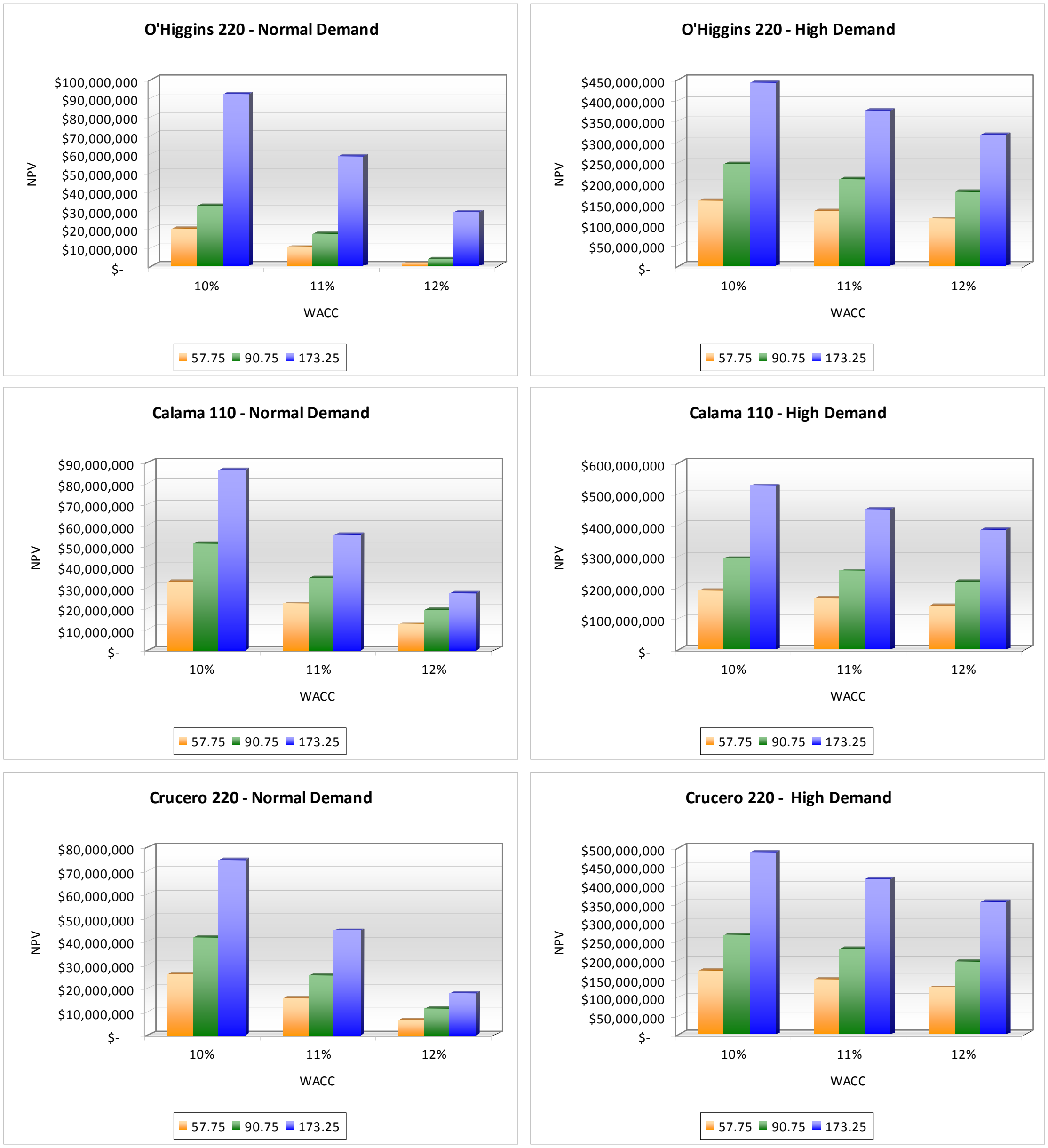

Figure 5-16: NPV for Firm Capacity, No Contract and Registered CDM Project

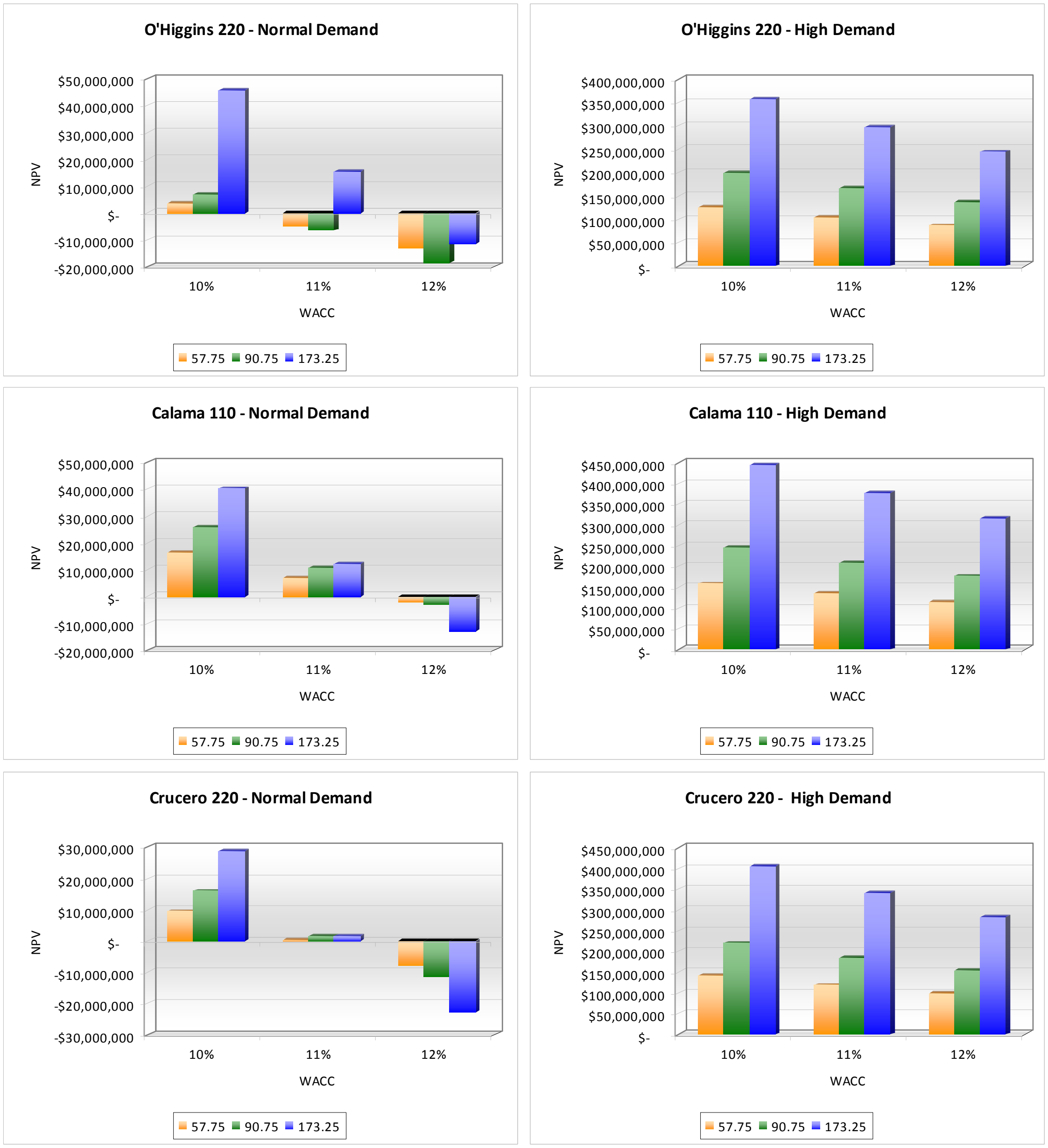

Figure 5-17: NPV for No Firm Capacity, No Contract and Registered CDM Project

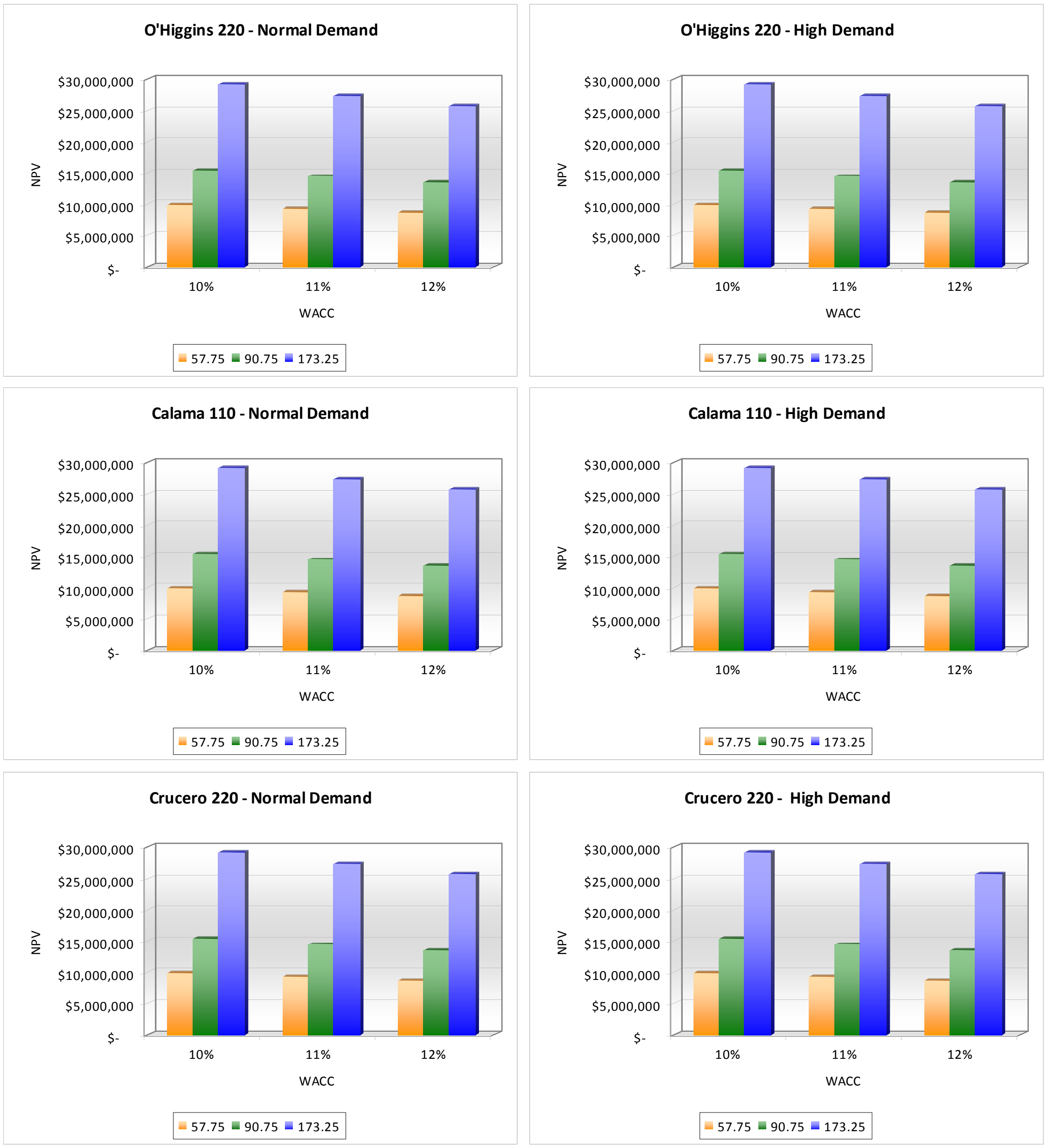

Figure 5-18: NPV for No Firm Capacity and Contract

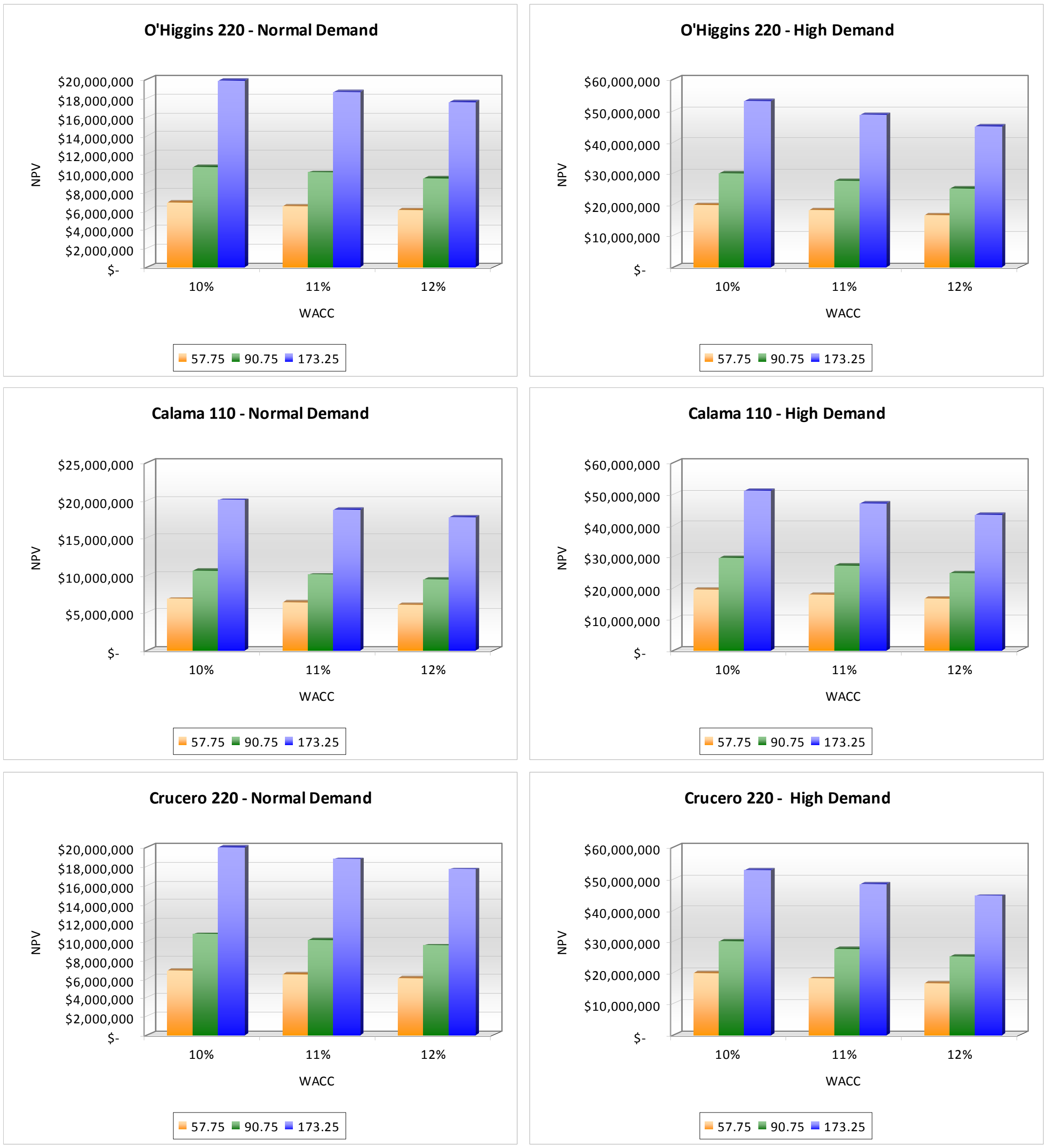

Figure 5-19: NPV for Firm Capacity and Contract

Appendix I. LAW PENALTY AND NEGATIVE NPV

Law Penalty @ 0.4UTM				
		10%	11%	12%
57.75	1	$39,778,679.77	$37,207,765.11	$34,900,144.73
	2	$39,778,679.77	$37,207,765.11	$34,900,144.73
	3	$39,778,679.77	$37,207,765.11	$34,900,144.73
90.75	4	$62,509,717.82	$58,469,685.54	$54,843,403.85
	5	$62,509,717.82	$58,469,685.54	$54,843,403.85
	6	$62,509,717.82	$58,469,685.54	$54,843,403.85
173.25	7	$119,335,344.61	$111,622,645.51	$104,699,824.69
	8	$119,335,344.61	$111,622,645.51	$104,699,824.69
	9	$119,335,344.61	$111,622,645.51	$104,699,824.69
57.75	10	$39,778,679.77	$37,207,765.11	$34,900,144.73
	11	$39,778,679.77	$37,207,765.11	$34,900,144.73
	12	$39,778,679.77	$37,207,765.11	$34,900,144.73
90.75	13	$62,509,717.82	$58,469,685.54	$54,843,403.85
	14	$62,509,717.82	$58,469,685.54	$54,843,403.85
	15	$62,509,717.82	$58,469,685.54	$54,843,403.85
173.25	16	$119,335,344.61	$111,622,645.51	$104,699,824.69
	17	$119,335,344.61	$111,622,645.51	$104,699,824.69
	18	$119,335,344.61	$111,622,645.51	$104,699,824.69

1. *Adapted System NPV*

		Without Firm Power Payment and Unregistered CDM Project					With Firm Power Payment and Unregistered CDM Project		
		10%	11%	12%			10%	11%	12%
57.75	1	-$44,619,653	-$48,978,687	-$52,960,380	57.75	1	-$35,129,355	-$39,918,571	-$44,291,564
	2	-$37,159,775	-$41,993,741	-$46,401,816		2	-$27,692,540	-$32,955,013	-$37,752,902
	3	-$41,605,420	-$46,193,519	-$50,379,392		3	-$32,132,726	-$37,149,796	-$41,725,891
90.75	4	-$68,539,430	-$75,328,783	-$81,528,885	90.75	4	-$53,780,504	-$61,240,253	-$68,050,098
	5	-$57,716,385	-$65,213,494	-$72,048,391		5	-$43,016,771	-$51,180,366	-$58,621,527
	6	-$63,286,786	-$70,476,303	-$77,033,555		6	-$48,578,465	-$56,435,228	-$63,599,412
173.25	7	-$131,577,934	-$144,345,945	-$156,000,642	173.25	7	-$104,589,425	-$118,597,837	-$131,379,736
	8	-$115,027,040	-$128,938,896	-$141,617,040		8	-$88,204,623	-$103,347,141	-$117,143,768
	9	-$121,085,766	-$134,611,547	-$146,943,823		9	-$94,235,236	-$108,992,590	-$122,444,184
57.75	10	$209,213,458	$196,862,673	$185,477,022	57.75	10	$225,520,095	$212,153,160	$199,856,296
	11	$20,489,371	$10,463,864	$1,453,335		11	$36,752,026	$25,712,473	$15,792,675
	12	$11,507,739	$2,161,098	-$6,245,071		12	$27,792,722	$17,430,658	$8,113,958
90.75	13	$5,408,464	-$7,988,743	-$20,049,394	90.75	13	$30,604,481	$15,631,442	$2,158,135
	14	$31,769,868	$16,207,591	$2,223,302		14	$56,693,749	$39,581,535	$24,207,302
	15	$18,987,565	$4,421,191	-$8,677,580		15	$44,129,333	$27,989,709	$13,480,612
173.25	16	$4,794,578	-$20,331,023	-$42,936,193	173.25	16	$51,214,549	$23,194,426	-$2,005,839
	17	$46,675,636	$17,928,314	-$7,884,403		17	$92,664,635	$61,040,475	$32,649,103
	18	$30,021,931	$2,714,498	-$21,824,970		18	$76,037,946	$45,852,106	$18,732,584

		Without Firm Power Payment and Registered CDM Project					With Firm Power Payment and Registered CDM Project		
		10%	11%	12%			10%	11%	12%
57.75	1	-$37,672,230	-$42,480,280	-$46,865,003	57.75	1	-$28,181,932	-$33,420,163	-$38,196,187
	2	-$30,212,352	-$35,495,334	-$40,306,439		2	-$20,745,118	-$26,456,605	-$31,657,525
	3	-$34,657,997	-$39,695,111	-$44,284,015		3	-$25,185,303	-$30,651,388	-$35,630,514
90.75	4	-$57,613,883	-$65,109,359	-$71,943,268	90.75	4	-$42,854,956	-$51,020,829	-$58,464,481
	5	-$46,790,838	-$54,994,070	-$62,462,774		5	-$32,091,224	-$40,960,941	-$49,035,910
	6	-$52,361,239	-$60,256,879	-$67,447,938		6	-$37,652,918	-$46,215,804	-$54,013,795
173.25	7	-$110,675,693	-$124,794,626	-$137,661,893	173.25	7	-$83,687,184	-$99,046,518	-$113,040,987
	8	-$94,124,799	-$109,387,576	-$123,278,290		8	-$67,302,382	-$83,795,822	-$98,805,018
	9	-$100,183,525	-$115,060,227	-$128,605,073		9	-$73,332,995	-$89,441,271	-$104,105,434
57.75	10	$216,160,880	$203,361,081	$191,572,399	57.75	10	$232,467,517	$218,651,567	$205,951,673
	11	$27,436,794	$16,962,272	$7,548,712		11	$43,699,448	$32,210,880	$21,888,053
	12	$18,455,161	$8,659,506	-$149,694		12	$34,740,144	$23,929,065	$14,209,335
90.75	13	$16,334,011	$2,230,681	-$10,463,777	90.75	13	$41,530,029	$25,850,867	$11,743,752
	14	$42,695,415	$26,427,016	$11,808,919		14	$67,619,296	$49,800,959	$33,792,919
	15	$29,913,113	$14,640,616	$908,037		15	$55,054,880	$38,209,133	$23,066,229
173.25	16	$25,696,819	-$779,703	-$24,597,444	173.25	16	$72,116,790	$42,745,745	$16,332,910
	17	$67,577,877	$37,479,633	$10,454,347		17	$113,566,876	$80,591,794	$50,987,852
	18	$50,924,172	$22,265,818	-$3,486,220		18	$96,940,187	$65,403,425	$37,071,333

2. *Non-Adapted System Negative NPV*

With Firm Power Payment and Non Registered CDM Project

		NPV
	CASE\WACC	12%
57.75	O'Higgins 220	-$4,677,677.89
90.75	O'Higgins 220	-$5,985,229.44
173.25	Crucero 220	-$709,263.79

Without Firm Power Payment and Non Registered CDM Project

		NPV		
	CASE\WACC	10%	11%	12%
57.75	O'Higgins 220	-$3,455,280.40	-$11,702,647.39	-$19,128,325.84
	Calama 110			-$8,055,686.51
	Crucero 220		-$6,150,962.80	-$14,036,658.08
90.75	O'Higgins 220	-$3,965,664.58	-$16,835,747.55	-$28,421,748.23
	Calama 110			-$12,475,696.03
	Crucero 220		-$8,544,324.17	-$20,848,260.58
173.25	O'Higgins 220		-$3,956,755.95	-$29,892,691.74
	Calama 110		-$7,266,583.15	-$31,313,088.15
	Crucero 220		-$17,952,687.33	-$41,157,581.89

Without Firm Power Payment and Registered CDM Project

		NPV	
	CASE\WACC	11%	12%
57.75	O'Higgins 220	-$5,204,239.94	-$13,032,948.71
	Calama 110		-$1,960,309.37
	Crucero 220		-$7,941,280.95
90.75	O'Higgins 220	-$6,616,323.38	-$18,836,131.31
	Calama 110		-$2,890,079.12
	Crucero 220		-$11,262,643.67
173.25	O'Higgins 220		-$11,553,942.32
	Calama 110		-$12,974,338.72
	Crucero 220		-$22,818,832.46

Appendix J. MARGINAL COST VARIATIONS

1. Adapted System [US$/MWh]

	Normal Demand								
	57.75			90.75			173.25		
	O'Higgins 220	Calama 110	Crucero 220	O'Higgins 220	Calama 110	Crucero 220	O'Higgins 220	Calama 110	Crucero 220
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9
2008	-$2.00	-$2.09	-$2.12	-$2.94	-$3.04	-$3.06	-$3.84	-$3.94	-$3.96
2009	-$2.83	-$2.95	-$2.98	-$3.10	-$3.21	-$3.24	-$3.38	-$3.49	-$3.52
2010	-$3.24	-$3.35	-$3.38	-$4.09	-$4.21	-$4.24	-$4.39	-$4.51	-$4.54
2011	-$3.66	-$3.76	-$3.78	-$4.10	-$4.20	-$4.22	-$4.71	-$4.81	-$4.83
2012	-$0.87	-$0.93	-$0.95	-$1.15	-$1.21	-$1.23	-$2.51	-$2.57	-$2.58
2013	-$0.00	-$0.03	-$0.03	-$0.00	-$0.03	-$0.03	-$0.01	-$0.03	-$0.04
2014	-$0.01	-$0.03	-$0.04	-$0.01	-$0.03	-$0.04	-$0.05	-$0.07	-$0.08
2015	-$0.01	-$0.04	-$0.05	-$0.03	-$0.05	-$0.06	-$0.03	-$0.06	-$0.06
2016	-$0.00	-$0.03	-$0.03	-$0.01	-$0.04	-$0.05	-$0.01	-$0.04	-$0.04
2017	-$0.01	-$0.04	-$0.05	-$0.01	-$0.04	-$0.05	-$0.03	-$0.05	-$0.06
2018	-$0.01	-$0.04	-$0.05	-$0.02	-$0.04	-$0.05	-$0.03	-$0.06	-$0.06
2019	-$0.01	-$0.04	-$0.05	-$0.02	-$0.04	-$0.05	-$0.03	-$0.06	-$0.06
2020	-$0.01	-$0.04	-$0.05	-$0.02	-$0.04	-$0.05	-$0.03	-$0.06	-$0.06
2021	-$0.01	-$0.04	-$0.05	-$0.02	-$0.04	-$0.05	-$0.03	-$0.06	-$0.06
2022	-$0.01	-$0.04	-$0.05	-$0.02	-$0.04	-$0.05	-$0.03	-$0.06	-$0.06

	High Demand								
	57.75			90.75			173.25		
	O'Higgins 220	Calama 110	Crucero 220	O'Higgins 220	Calama 110	Crucero 220	O'Higgins 220	Calama 110	Crucero 220
	Case 10	Case 11	Case 12	Case 13	Case 14	Case 15	Case 16	Case 17	Case 18
2008	-$2.00	-$2.09	-$2.12	-$2.94	-$3.04	-$3.06	-$3.84	-$3.94	-$3.96
2009	-$2.83	-$2.95	-$2.98	-$3.10	-$3.21	-$3.24	-$3.38	-$3.49	-$3.52
2010	-$3.60	-$3.73	-$3.77	-$4.56	-$4.69	-$4.72	-$4.89	-$5.02	-$5.05
2011	-$5.16	-$5.30	-$5.33	-$5.78	-$5.92	-$5.96	-$6.64	-$6.78	-$6.82
2012	-$1.10	-$1.18	-$1.20	-$1.46	-$1.53	-$1.55	-$3.17	-$3.25	-$3.27
2013	-$0.00	-$0.07	-$0.09	-$0.01	-$0.08	-$0.09	-$0.02	-$0.09	-$0.11
2014	-$0.02	-$0.10	-$0.12	-$0.02	-$0.10	-$0.12	-$0.13	-$0.21	-$0.22
2015	-$0.04	-$0.12	-$0.14	-$0.08	-$0.16	-$0.18	-$0.09	-$0.17	-$0.19
2016	-$0.01	-$0.08	-$0.10	-$0.04	-$0.12	-$0.14	-$0.04	-$0.12	-$0.14
2017	-$0.04	-$0.12	-$0.15	-$0.04	-$0.13	-$0.15	-$0.08	-$0.16	-$0.18
2018	-$0.04	-$0.12	-$0.14	-$0.05	-$0.13	-$0.16	-$0.09	-$0.18	-$0.20
2019	-$0.04	-$0.12	-$0.14	-$0.05	-$0.13	-$0.16	-$0.09	-$0.18	-$0.20
2020	-$0.04	-$0.12	-$0.14	-$0.05	-$0.13	-$0.16	-$0.09	-$0.18	-$0.20
2021	-$0.04	-$0.12	-$0.14	-$0.05	-$0.13	-$0.16	-$0.09	-$0.18	-$0.20
2022	-$0.04	-$0.12	-$0.14	-$0.05	-$0.13	-$0.16	-$0.09	-$0.18	-$0.20

2. *Non-Adapted System [US$/MWh]*

	Normal Demand								
	57.75			90.75			173.25		
	O'Higgins 220	Calama 110	Crucero 220	O'Higgins 220	Calama 110	Crucero 220	O'Higgins 220	Calama 110	Crucero 220
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9
2008	-$1.35	-$1.57	-$1.53	-$3.90	-$4.59	-$4.18	-$7.02	-$7.44	-$7.36
2009	-$3.00	-$3.48	-$3.39	-$4.09	-$4.73	-$4.59	-$8.13	-$9.24	-$9.00
2010	-$1.92	-$2.16	-$2.10	-$3.98	-$4.70	-$4.65	-$6.33	-$7.84	-$7.67
2011	-$2.83	-$3.26	-$3.23	-$5.17	-$5.59	-$5.57	-$8.43	-$9.43	-$9.09
2012	-$4.79	-$5.04	-$5.03	-$5.13	-$5.32	-$5.31	-$7.41	-$7.64	-$7.54
2013	-$0.59	-$0.66	-$0.66	-$0.90	-$1.49	-$1.47	-$2.71	-$5.97	-$5.90
2014	-$0.60	-$1.35	-$1.33	-$1.24	-$2.02	-$2.01	-$2.24	-$2.64	-$2.61
2015	-$0.05	-$0.26	-$0.20	-$0.07	-$0.44	-$0.38	-$0.49	-$1.26	-$1.18
2016	-$0.20	-$0.42	-$0.41	-$0.65	-$0.96	-$0.95	-$1.54	-$2.32	-$2.14
2017	-$0.11	-$0.21	-$0.20	-$0.18	-$0.93	-$0.89	-$0.93	-$1.48	-$1.42
2018	-$0.30	-$0.53	-$0.50	-$0.55	-$0.90	-$0.80	-$0.77	-$1.28	-$1.27
2019	-$0.30	-$0.53	-$0.50	-$0.55	-$0.90	-$0.80	-$0.77	-$1.28	-$1.27
2020	-$0.30	-$0.53	-$0.50	-$0.55	-$0.90	-$0.80	-$0.77	-$1.28	-$1.27
2021	-$0.30	-$0.53	-$0.50	-$0.55	-$0.90	-$0.80	-$0.77	-$1.28	-$1.27
2022	-$0.30	-$0.53	-$0.50	-$0.55	-$0.90	-$0.80	-$0.77	-$1.28	-$1.27

	High Demand								
	57.75			90.75			173.25		
	O'Higgins 220	Calama 110	Crucero 220	O'Higgins 220	Calama 110	Crucero 220	O'Higgins 220	Calama 110	Crucero 220
	Case 10	Case 11	Case 12	Case 13	Case 14	Case 15	Case 16	Case 17	Case 18
2008	-$1.35	-$1.57	-$1.53	-$3.90	-$4.59	-$4.18	-$7.02	-$7.44	-$7.36
2009	-$3.00	-$3.48	-$3.39	-$4.09	-$4.73	-$4.59	-$8.13	-$9.24	-$9.00
2010	-$4.55	-$5.01	-$4.86	-$6.37	-$7.39	-$7.09	-$11.34	-$12.97	-$12.66
2011	-$5.93	-$7.91	-$6.35	-$9.15	-$10.11	-$9.63	-$17.86	-$19.99	-$19.26
2012	-$1.59	-$2.27	-$2.16	-$4.17	-$4.71	-$4.27	-$5.84	-$6.24	-$6.20
2013	-$7.20	-$8.10	-$7.98	-$10.78	-$11.92	-$11.66	-$22.85	-$23.93	-$23.76
2014	-$8.66	-$9.88	-$8.89	-$12.87	-$15.02	-$14.01	-$30.26	-$33.42	-$32.46
2015	-$5.48	-$5.55	-$5.50	-$8.56	-$10.65	-$10.33	-$17.49	-$20.72	-$18.29
2016	-$4.31	-$6.02	-$4.75	-$10.07	-$13.06	-$11.44	-$20.03	-$22.44	-$21.34
2017	-$2.03	-$1.37	-$2.17	-$3.94	-$3.11	-$4.18	-$5.83	-$6.27	-$6.13
2018	-$0.83	-$0.63	-$0.91	-$1.35	-$1.25	-$1.50	-$3.10	-$3.82	-$4.08
2019	-$0.83	-$0.63	-$0.91	-$1.35	-$1.25	-$1.50	-$3.10	-$3.82	-$4.08
2020	-$0.83	-$0.63	-$0.91	-$1.35	-$1.25	-$1.50	-$3.10	-$3.82	-$4.08
2021	-$0.83	-$0.63	-$0.91	-$1.35	-$1.25	-$1.50	-$3.10	-$3.82	-$4.08
2022	-$0.83	-$0.63	-$0.91	-$1.35	-$1.25	-$1.50	-$3.10	-$3.82	-$4.08