upme
unidad de planeación minero energética

IDB

Libertad y Orden
República de Colombia
Ministerio de Minas y Energía

IMPACT ANALYSIS FOR INTEGRATION OF WIND POWER GENERATION IN COLOMBIA

PROGRESS STUDY REPORT 03

MARKET & REGULATORY ASPECTS

OCTOBER 2014

COWI

ADDRESS COWI A/S
Parallelvej 2
2800 Kongens Lyngby
Denmark

TEL +45 56 40 00 00
FAX +45 56 40 99 99
WWW cowi.com

IMPACT ANALYSIS FOR INTEGRATION OF WIND POWER GENERATION IN COLOMBIA

PROGRESS STUDY REPORT 03

MARKET & REGULATORY ASPECTS

OCTOBER 2014

PROJECT NO.	A-038811
DOCUMENT NO.	PSR03
VERSION	1
DATE OF ISSUE	28Oct14
PREPARED	TEP, KELA
CHECKED	FLJS. LOBU
APPROVED	KELA

CONTENTS

APPENDICES

1 Executive summary

The Colombian electricity market

This report on market and regulatory aspects deals with the current framework for wind power in Colombia, the correlation and complementarity between wind and hydro, and assessment of the firm energy factor (ENFICC) for wind power. The report also includes a review of international experiences (Denmark and South Africa) and a discussion of wind energy integration strategies.

The electricity sector in Colombia is dominated by large hydro power and conventional thermal generation. Approximately, 1 % of the electricity generation in 2010 was from wind power, biomass and waste.

The high reliance of hydro power in the Colombian system poses challenges with regard to reliability during El Niño periods where drought substantially reduces hydroelectric generation with potentially serious consequences. This underlines the importance of having backup generation to replace hydro during El Niño periods. In addition to this, the expected increase in electricity demand of 2.8 - 3.8 % per year, together with the phasing out of existing power plants when they reach their end of lifetime implies that there will be a need for new power generation facilities.

Current framework for wind power

According to the current framework for wind power, wind turbines in Colombia receive, in addition to the revenue from electricity sale, also revenue from reliability charge and revenue from CERs (Certified Emission Reductions). They also have a fifteen-year tax-exemption period for power generated assuming that they receive carbon emission certificates and assuming that 50 % of the income from this is invested locally in social benefit programs.

On the cost-side, wind turbines pay CERE (Real equivalent Cost of the Capacity Charge) and transmission/grid charges.

The current framework for wind power has not triggered any large-scale development of wind power in Colombia. For the specific wind sites analysed in this project, the financial analyses have also shown that these projects are not financially viable. The estimated IRR becomes far below the rate that developers expect.

Correlation and complementarity between wind and hydro

This report supports the findings already presented in studies completed in 2010 and 2012 (Ref. 4 & 5).

This report takes basis in wind data provided from the Northern La Guajira province only and four hydro power plants selected by the Client.

The analyses of the correlation and complementarity between wind and hydro in this study confirm that a complementarity between the Hydro and Wind resources exists.

- Wind Speed vs. Hydro Inflow
  Three months (Jan/Feb/Mar) in general have normalised Wind Speed above its yearly average and normalised Hydro Inflow below the yearly average when the timespan 1997-2012 is analysed. (April having a high occurrence of months being favourable wind months could also be considered as a favourable wind month as discussed later).

- Wind Production vs. Hydro Production
  Three months (Jan/Feb/Mar) in general have normalised Wind Production above its yearly average and normalised Hydro Production below the yearly average. The months from August to December are not identified as favourable wind months.

- The wind generators will relatively produce more energy during the daily medium and high power grid load time span compared with the low power grid load time span

- El-Niño / CREG dry month influence
  The study cannot verify a correlation of the wind speed in El-Niño months and the dry months (Dec… Apr) as being defined by CREG.

  The wind production as a tomb rule seems to be above the monthly average in the dry months defined by CREG.

  No clear interrelation between the wind energy production and the El-Niño months has been identified.

  The monthly wind speed in general is above average in the CREG dry months. (Dec-Jan-Feb-Mar-Apr)

  The study verifies that the average monthly wind energy production in general are higher during the El-Niño months compared with all months and the wet months (not El-Niño months) when the August 1995-March 2013 time span is considered.

  It is observed that Dec is not a favourable wind month although it is defined as a dry month by CREG.

Analysis of firm energy factor, ENFICC

Until recently, wind power was not eligible for firm energy payment. However, in 2011, CREG suggested two alternative methods for calculating ENFICCs for wind plants; one for plants that have less than 10 years of information on wind resources, and another one for plants that have at least 10 years of information.

However, CREG's approach for determining the firm energy factor for wind energy does not consider the complementarity between the hydro and wind energy production. This report indicates

- that the EFICC for the wind generation plants could be increased when the complementarity is taken into consideration
- that larger wind turbine units (compared with existing 1,3MW at Jepirachi) could justify an increase in the ≈ +6% of the $ENFICC_{95\%}$
- that an increased $ENFICC_{95\%}$ ≈ +6% could be justified based on the relatively higher wind energy production during the El-Niño months (assumed having relatively less water resources)
- that even larger $ENFICC_{95\%}$ figures (up to ≈ 39%) could be augmented if the CREG dry months are considered.

The study also has analysed if a developer's portfolio of wind energy and hydro energy generation plants could justify a higher ENFICC compared with two separate production plants. (Wind and Hydro isolated)

The study has not been able to confirm the findings in previous reports (Ref. 4 & 5) that indicated higher ENFICC for a Wind/Hydro portfolio compared with two isolated Wind and Hydro generation plants. However a positive trend ranging from 3% to 12% is indicated, but should be verified by additional studies.

Review of international experiences

Denmark has a high amount of wind power covering almost up to 30 % of the domestic electricity demand. Onshore wind turbines normally receive the market price of electricity (hourly price) plus an add-on to the market price. Offshore turbines normally receive a fixed agreed price per MWh.

Long term planning and a stable and supportive policy framework in Denmark have been one of the main keys to the successful large-scale integration of wind power. The political framework embraces a range of issues such as common goals or targets, design of taxed and incentives for developers as well as regulation and legislation to ensure well-functioning market conditions that stimulate investments.

South Africa, which has always been heavily dependent on coal, is looking at ways to diversify its power generating capacity. The African Development Bank, the Treasury and Eskom are working on a renewable energy programme that involves independent power producers.

The government is also looking to support sustainable green energy initiatives on a national scale through a diverse range of clean-energy options. According to the Integrated Resource Plan 2010, which is a 20-year projection on electricity demand and production, about 42 % of electricity generated must come from renewable resources.

A study of the power sector in South Africa has analysed the capacity credit from wind turbines, which is the percentage of the maximum generation capacity that will replace alternative generation technologies in the system to achieve the equivalent overall system reliability. Overall, for a wind generation plant in South Africa, the capacity credit of wind generation will be between 25 % and 30 % for installed wind generation of up to 10,000 MW. In the case of higher wind penetration (25,000 MW), the capacity credit of wind generation in South Africa will drop below 20 %.

Wind energy integration strategies

A key issue with regard to wind power in Colombia, and a barrier for large-scale deployment, is the financial viability of the wind projects. The IRR seems to be much lower than what is expected from developers. However, the IRR is very sensitive to changes in the tariff and the investment cost. If either the tariff is increased by 10-20 % or the investment costs could be lowered by 10-20 %, the IRR will reach a level within the range that developers expect.

This also means that the wind power development in Colombia could possibly be boosted if there was either a premium feed-in tariff of 10-20 % of the sales price or an investment grant of 10-20 % of the investment. As the costs related to transmission and grid connection may correspond to app. 10 % of the total investment budget (CAPEX), wind projects would also be much more profitable if these costs were not born by the wind developer

In addition to the financial aspects, it is important to remove barriers related to administration and grid access. Furthermore, it is important to ensure an effective operation of the power system in order to make the system more adaptable to larger shares of variable renewable power.

2 Introduction

Given the growing interest of public and private investors to develop medium and large scale renewable power generation projects in Colombia, from energy sources such as wind, solar, biomass and geothermal, and being aware of the country's large potential, the Mining and Energy Planning Unit (UPME), along with the Inter-American Development Bank (IDB), have been developing the project "Catalytic Investments for Geothermal Power", which includes the identification of barriers for development of renewable energy and mechanisms for its removal.

A specific analysis for the integration of wind power in Colombia has been identified, to be carried out under the retainer contract signed by IDB with the international consultancy firm COWI A/S, developed to perform studies for the integration of wind power in different countries worldwide.

This report makes up the Market and Regulatory Aspects Report of the complete study. The full study is reported in the following documents:

- Final Project Report
- Study Report 01: Power System Technical Analysis – Neplan
- Study Report 02: AEP & Financial Feasibility Analysis
- Study Report 03: Market & Regulatory Aspects
- Study Report 04: NEPLAN Training Package

The final Market & Regulatory Aspects Report will be finalised based on comments and inputs received by the Client.

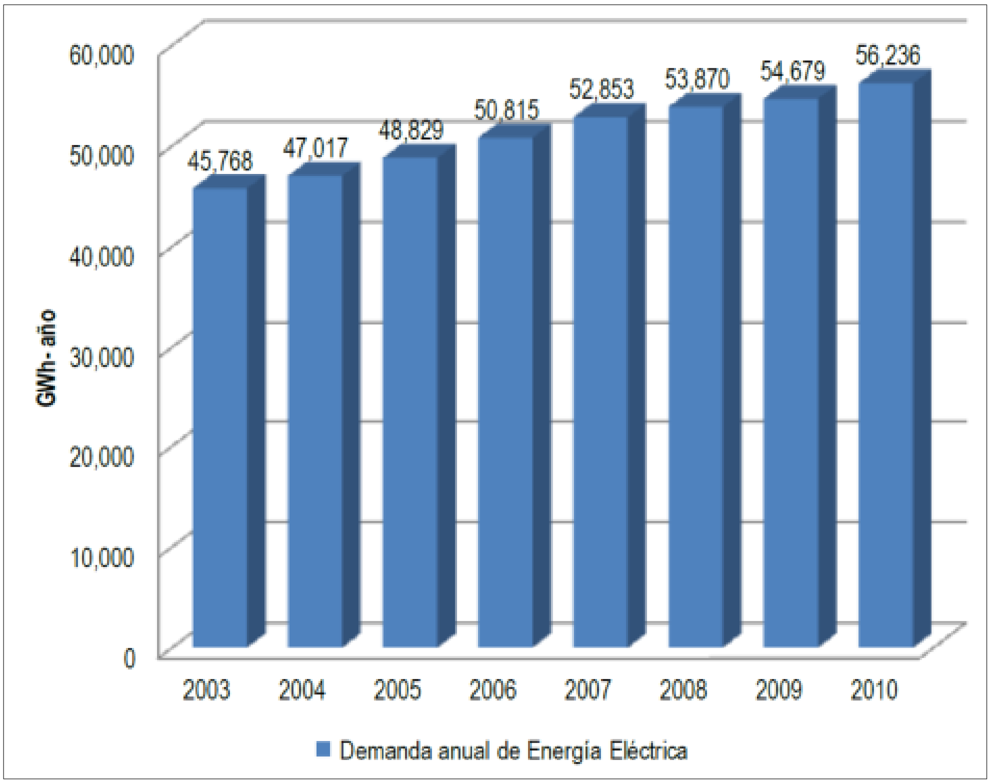
3 The Colombian electricity market

3.1 Current situation

According to the UPME Generation-Transmission Reference Expansion Plan 2011-2025, the total electricity demand in Colombia in 2010 was 56,236 GWh.

The figure below shows the development in total electricity demand from 2003 to 2010.

Table 1: Development in total electricity net consumption, 1980-2010

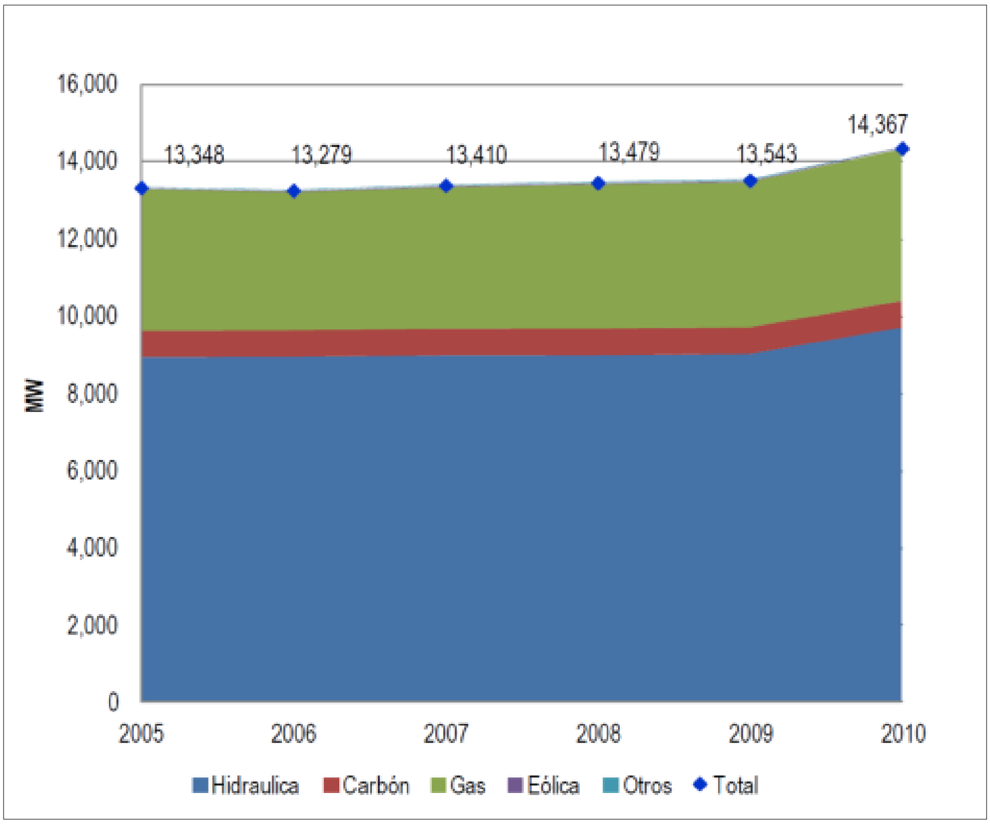


Source: UPME Generation-Transmission Reference Expansion Plan 2011-2025

The electricity sector in Colombia is dominated by large hydropower and conventional thermal generation. According to the UPME Generation-

Transmission Reference Expansion Plan 2011-2025, the installed capacities from 2005 to 2010 were as shown in the figure below.

Figure 1: Installed capacities 2005-2010, MW



Source: UPME Generation-Transmission Reference Expansion Plan 2011-2025

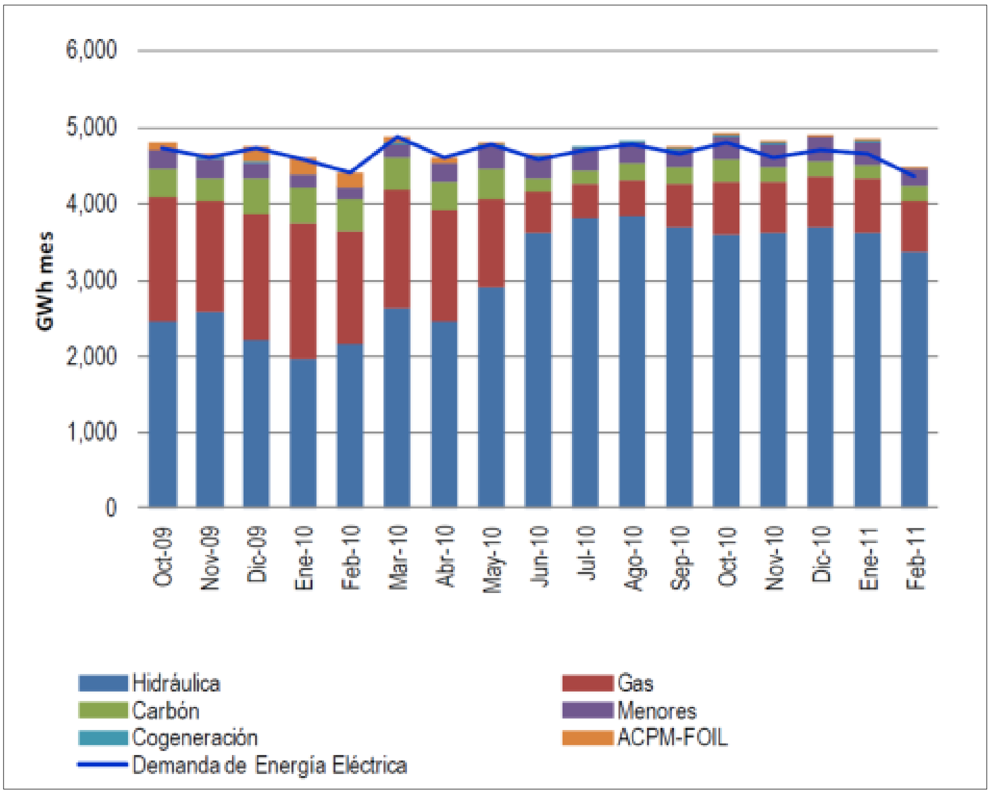
It appears from the figure that most of the installed power capacity (app. 67 %) is at hydro power plants and app. 33 % of the capacity is at conventional thermal power plants. There is also a small share of wind power and biomass and waste (< 1 %).

The high share of hydropower capacity in Colombia makes the system vulnerable to climate variations. In dry years, when hydropower cannot operate at full capacity, thermal power plants generate more than 50 % of total demand, whereas in wet years, the share can be less than 20 %. In second half of 2010, the share of hydropower reached almost 75 %.

Since the mid 1990's, gas-powered plants have been the preferred option to back up power generation during periods of peak demand and during dry seasons in Colombia. Combined-cycle gas turbines (CCGT) have shorter lead times and lower capital costs than large hydro plants. This, along with incentives given to thermal plants between 1997 and 2005, made CCGT a commercially attractive option for increasing the reliability of power supply in Colombia.

The figure below shows the electricity generation in Colombia from October 2009 to February 2011. In 2010, the total electricity generation was 56,897 GWh.

Figure 2: Electricity generation from October 2009 to February 2011, GWh

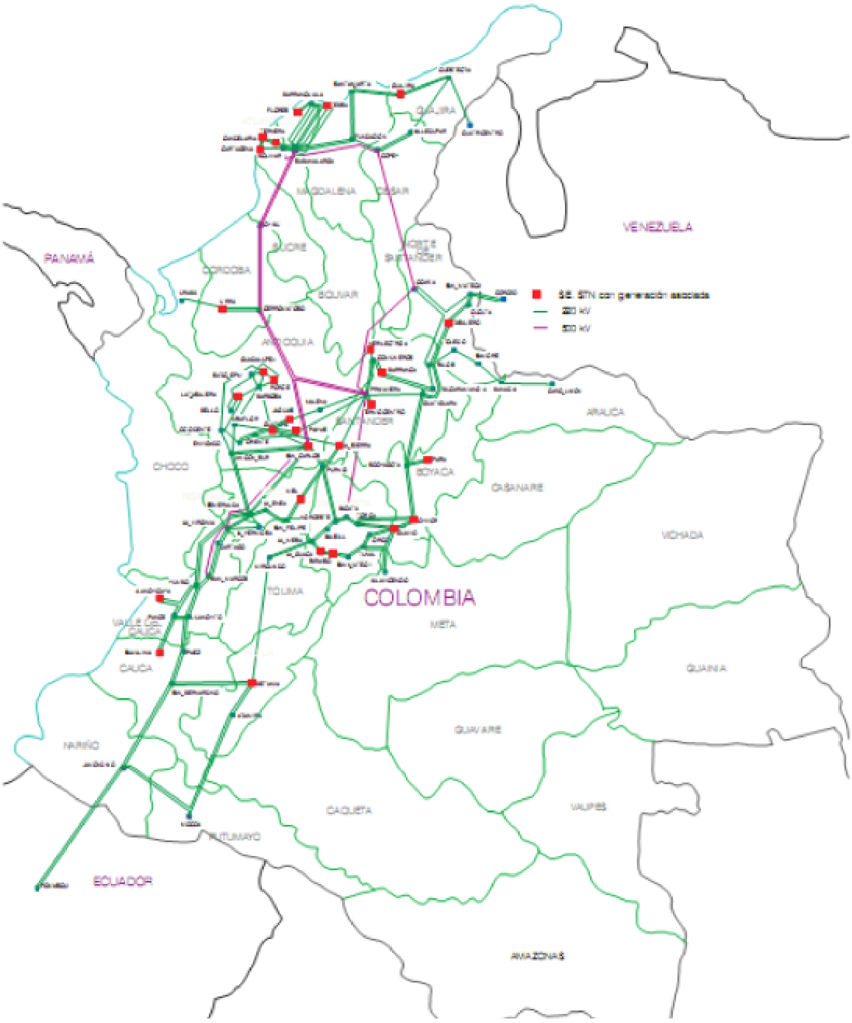


Source: UPME Generation-Transmission Reference Expansion Plan 2011-2025

In 2010 most of the electricity generation (app. 72 %) was from hydro power plants and app. 27 % of the electricity generation was from conventional thermal power plants. Approximately 1 % of the electricity generation in 2010 was from wind power, biomass, and waste.

Colombia has interconnections to the neighbouring countries Ecuador (500 MW), Venezuela (336 MW) and a planned interconnector to Panama (300 MW).

Table 2: The Colombian transmission system



In 2010, Colombia had a net export to neighbouring countries of 788 GWh corresponding to app. 1 % of the total electricity net generation.

3.2 Future situation

According to Colombia's Reference Expansion Plan 2006-2020 [CREG 2006], the electricity demand is expected to continue increasing by between 2.8 and 3.8 % per year in the "Medium" scenario. The increase in electricity demand, together with the phasing out of existing power plants when they reach their end of lifetime, means that there will be a need for establishing new power generation facilities.

The Colombian system relies very heavily on hydropower, but thermal generation also play an important role. In a normal year, the reliance on hydro generation is especially evident; it accounts for about 80 % of electricity output. This poses problems for reliability during periods of El Niño. Drought substantially reduces hydroelectric generation with potentially serious economic and political consequences. More generally, demand for water for all uses is growing and this raises the value of water and reduces its availability for hydroelectric generation.

This fact underlines the importance of having backup generation to replace hydro during periods of El Niño. [Oxford Institute 2012]

There are a number of reasons why Colombia may wish to consider non-conventional renewable sources of power including wind as alternatives to coal and gas-fired plants:

- Colombia risks an increasing carbon footprint and international experiences have shown that it is easier to reduce or at least manage growth in CO_2-emissions through the electricity sector than in other carbon-emitting sectors, such as transport.

- There appears to be a complementarity (or hedge) between hydro on the one hand, and wind generation on the other. During El Niño periods, less rain appears to coincide with stronger winds.

- Including non-traditional renewable energies in its energy portfolio may make the Colombian electricity sector and the economy less exposed to volatile hydrocarbon prices (since domestic prices for natural gas and international prices for coal are volatile).

- The costs of renewable power are declining and the cost of fossil-based generation is likely to rise.

- The negative externalities and the long lead times required for large hydro and coal plants contrast with relatively limited externalities and flexibility offered by non-conventional renewable sources of power.

The wind regime in Colombia is among the best in South America and according to [1] the potential for wind power is 18 GW, which is 900 times as much as the current capacity of 20 MW.

4 Current framework for wind power in Colombia

In 2002 Colombia created a general framework for promoting Renewable Energy Technologies. The existing framework for promoting renewable and wind power generation consists of the following initiatives:

- Law 697 of 2001 and Decree 3683 of 2003 which:
  - Incorporate renewables and energy ENFICC as part of the goals to be met by energy policy and create institutions to support their development.
  - Propose research funding for energy ENFICC, and
  - Include renewable options for non-interconnected regions.
- Law 788 of 2002 which:
  - Establishes a fifteen-year tax-exemption period for power generated from wind or biomass energy. To benefit from this tax-exemption scheme, generators must obtain carbon emission certificates, which are an additional source of income, and 50 % of this income must be invested locally in social benefit programs.

The policy for RETs has, however, not been able to trigger a large-scale development of wind power in Colombia. Between 2004 and 2010, the Colombian enabling framework promoted only one wind farm with a capacity of 19.5 MW.

According to [Isaac Dyner et. al. 2011] the Colombian framework has failed to promote wind power mainly because the incentives it provides (tax cuts) are not targeted at lowering entry barriers for renewables. The high capital costs of wind power, a market structure based on hydro technologies and a high market concentration create an unfavourable environment for investing in wind farms.

Another issue is the capacity and reliability charges, which have favoured generation expansion based on medium to large-scale hydro plants at the expense of other technologies, particularly non-conventional renewables. Unlike thermal and hydro plants, wind power technologies have no access to the capacity and reliability charges paid in Colombia and which between 1997 and 2006 contributed 49 % to the average generator's income. Although these charges are decreasing, they still represent a large share of the generator's revenues.

Reliability charges can be allocated regardless of technology and could in principle remunerate the capital costs of wind energy. In their current form, however, reliability charges do not provide a method of forecasting the power generated by intermittent sources other than that available for hydro sources. The contribution of hydroelectricity to power supply can be forecast from long historic time series, which are not available for wind, solar or other renewable energy technologies. Thus, it is not possible to make al reliable estimate of the contribution of wind power technologies to total energy supply during years of extreme weather conditions.

The capacity and reliability charges are described further below.

4.1 Reliability charges (payment for firm energy)

In 2006, CREG introduced a new scheme to ensure the long-term reliability of the electricity supply in Colombia, and in particular, to guarantee that there is always sufficient capacity available to meet peak demand during El Niño periods, when hydro resources are significantly reduced. The scheme allocates "firm energy obligations" (OEFs) to new and existing generation plant at price determined in competitive auctions. OEFs are "option contracts" that commit generating companies to supply given amounts of energy at a predetermined Scarcity Price. They receive the spot price for any additional generation above their firm energy obligation, and pay a penalty if they cannot meet their firm energy obligation, equal to the difference between the spot price and the scarcity price on the OEF quantity not met in any hour.

In return for agreeing to supply at the Scarcity Price, generators allocated OEFs in the auctions receive a fixed annual option fee (the firm energy price) for each capacity unit contracted. This option fee makes an important contribution to the recovery of fixed costs for generating plants that sell very little in normal times, such as the CCGT plants in central Colombia that generate infrequently outside of El Niño periods.

The maximum amount of firm energy that a generator may offer in a firm energy auction is known as its ENFICC which refers to the amount of energy a generator of a given type can reliably and continually produce during periods when hydro generation capacity is at a minimum.

The typical ENFICCs for different generation technologies in Colombian as a percentage of a plant's net capacity are:

- Hydro with storage, 55 %
- Hydro without storage, 30 %
- Coal, 97 %

- Natural gas, 93 %
- Fuel oil, 88 %
- Wind, 6 %

CREG resolution 071 of 2006 (Annex 3) describes in detail how the CREG calculates ENFICCs for the hydro and thermal plants that receive firm energy payments. For thermal plant this is essentially CEN*(1-IHF) where CEN = "effective net capacity" and IHF = the historical probability of forced (i.e. unplanned) outages.

The ENFICC of hydro plants is calculated using a computational model that maximizes the minimum energy that a hydro generation plant can produce monthly during dry periods. The model incorporates historical data on average monthly water inflows; discharges and restrictions in the water conduction systems, characteristics of the generation plants including the average ENFICC and their minimum and maximum generation; water reservoir data and other uses of water like aqueduct or irrigation and environmental restrictions; historical unavailability due to forced outages; and flow constraints.

The minimum production numbers are then ordered from least to greatest, and the lowest is defined as the plant's ENFICC Base, or the amount of energy the plant can be relied upon to produce with 100 % probability. In other words, ENFICC BASE corresponds to the minimum monthly energy supply obtained from the maximization model. The CREG also defines the $ENFICC_{95\%}$ the amount of energy the plant can be relied upon to produce with 95 % probability.

Until recently, wind power was not eligible for a firm energy payment in Colombia. In July 2011 however, CREG released a proposal for measuring ENFICCs for wind plants based upon the historical experience of EPM's Jepírachi plant. Following a broadly similar methodology to that applied to hydro plant, the CREG used historical generation data from 2004 to 2011 to estimate monthly capacity factors for the Jepírachi wind farm, and derived an ENFICC Base of 6 % and an ENFICC 95 % PSS of 7.3 %.

In the document from July 2011 and in its subsequent draft Resolution 148 of October 2011, the CREG suggests two alternative methods for calculating ENFICCs for wind plants; one for plants that have less than 10 years of information on wind resources, and another for plants that have at least 10 years of information. In the first case, they use the operating experience from Jepírachi as the basis for determining the ENFICCs for a new wind power plant, i.e. 6 % ENFICC BASE and 7.3 % ENFICC 95 % PSS.

For plants for which there is more than 10 years of wind data, they use the following formula:

E = min (24*1000*k*v3, 24*1000*CEN*(1-IHF))

Where:

E:	energy (kWh/day)
k:	conversion factor for wind plants
v:	average monthly wind speed (m/s)
IHF:	historic forced outage rate
CEN:	Effective net capacity (MW)

With this formula, the CREG constructs a probability distribution curve, from the lowest to the highest level of firm energy, using monthly values. The lowest firm energy factor corresponds to a 100 % probability of being exceeded and the highest value has a 0 % probability of being exceeded.

The World Bank study, on the other hand, suggested measuring ENFICCs for wind plants using the following exponential smoothing formula under which the “firm energy rating” (the ENFICC) is updated annually:

> *Firm energy rating in t+1 = (firm energy rating in t) + (energy produced in year t),*

The firm energy rating for the initial year could be based on recent data; for instance, plants located on the northern coast could use the period of generation recorded by Jepírachi. According to the World Bank, the firm energy rating will adjust quickly to the long run average level of firm energy capability, even if the initial estimate is wrong.

Applying their formula to a 24-year series of monthly wind and production data related to the Jepírachi plant, the WB estimated an average annual firm energy rating of 38 %, with a range between 25 % and 47 %. They also estimated a firm energy rating for dry seasons of 40 %, with a range from 30 % to 47 %.

The difference of these two approaches (WB and CREG) is significant when measured in terms of the financial consequences.

5 Correlation and complementarity between wind and hydro

5.1 Objective

The complementarity between the hydro and wind energy resources has been analysed in previous studies (reference 4 & 5). This study aims at reconfirming the previous findings and analysing the wind/hydro complementarity in relation to the El-Niño phenomena.

The previous studies indicate that the monthly wind energy production tends to be highest during the dry months with fewest water resources. CREG has defined the dry months to Dec-Apr (Reference 5, page 18-19). Thus the study also will review the occurrence of these "CREG dry months" defined in relation to the El-Niño phenomena.

The study will reconfirm that the wind energy production in general is higher during the El-Niño months compared with all the months and the wet months "not El-Niño months".

The wind/hydro complementarity analyse will investigate the relationship between the

- wind speed vs. river discharge
- wind energy vs. hydro energy production

The wind energy production will be estimated from wind series and the power curves of the wind turbines.

The hydro energy production will be extracted from actual production data informed by UMPE.

5.2 Geographical focus

The complementarity study considers wind energy production facilities in the Northern La Guajira province and hydro power production from whole Colombia. The selection of hydro power plants from the Colombian generation plants for use in this study will be based on the installed capacity [MW] for each unit and availability throughout the time span investigated.

5.3 Wind data series compilation

5.3.1 Data provided by UPME

The wind speed analyse takes basis in data provided by UMPE

- 10 m MET mast, 2001-2009
- 50 m MET mast, Jan 07 – Jul 13, (Apr-Jul 10 missing)

Also long-term satellite wind data “MERRA” from the time span 1983 – 2013 has been used for yearly correction and the elaboration of a full wind data series covering the years 1983-2013. Reference is made according to progress study report 02: AEP and Financial Feasibility section 2.1.5.

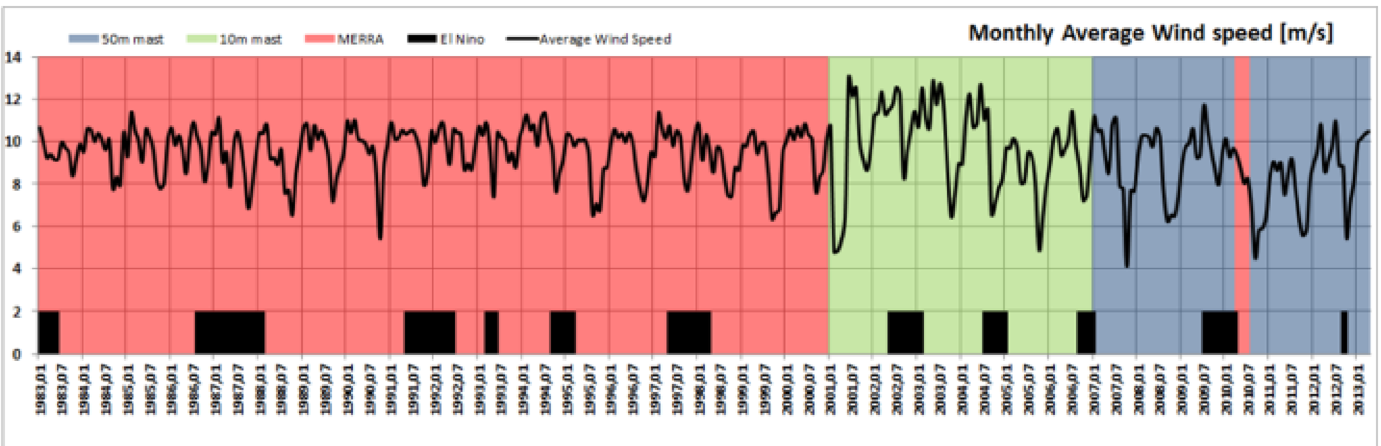
5.3.2 Compilation of wind speed profile 1983 - 2013

The method applied to elaborate the full wind data series is detailed in the study report 3 AEP and Financial Feasibility Study.

Three data series (200 x 2MW, 134x3MW & 15x1,3MW) average wind speed (1hour) for the time window January 1983 to July 2013 have been developed and constitute the basis for the analysis of the wind/hydro energy production correlation and complementarity.

Wind Farm	Hub Height	Yearly Average [m/s]
15 x 1.3 MW	60 m	9,2
200 x 2 MW	78 m	9,4
134 x 3 MW	84 m	9,6

The three data series have a slightly different average wind speed caused by the differences in the hub heights as indicated in the table beside. (Average wind speed increases with higher hub height).



The monthly average wind speed for the 200x2MW site assuming the hub height being 78 m is indicated in the figure above and is used for the further analysis.

The basis for the wind data through the years is also indicated. It is observed that the fluctuations of the monthly average from 2001 to 2013 (being based on actual measurements from MET masts) are more dominant, than the years composed from the MERRA basis. The standard deviation of the monthly average wind speed for the three scenarios and in total for all years are listed in the table below. The lower standard deviation on the MERRA based wind data is most likely due to the re-analysis applied in the generation of the MERRA data and does not represent the real variation in the monthly variation in the wind.

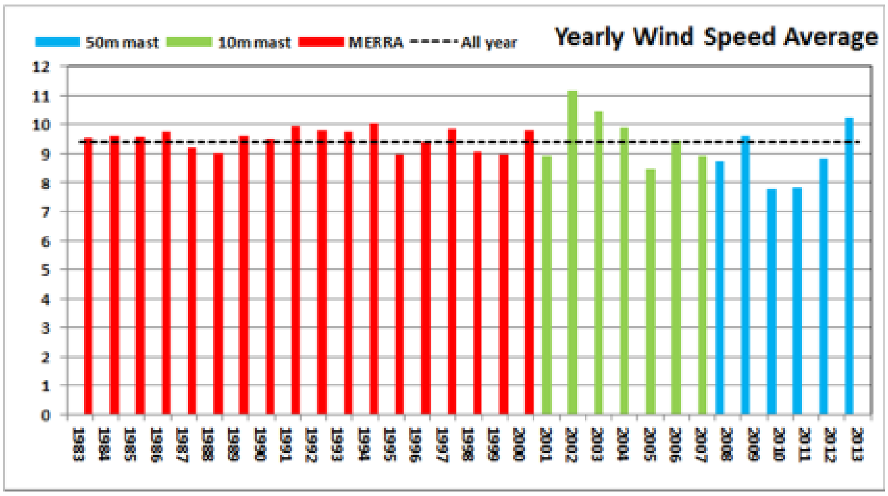
Wind speed at 78m hub height (Jan83-Mar13)

	MERRA	10m mast	50m mast	All
All months average	9,50	9,72	8,71	9,39
Standard Deviation	11,9%	21,6%	19,8%	16,3%
El Niño months (% of all months)	9,6 (101%)	9,81 (101%)	9.37 (107,6%)	9,61 (102,4%)
"Not El Niño months" (% of all months)	9,46 (99,6%)	9,71 (100%)	8.54 (98%)	9,31 (99,2%)

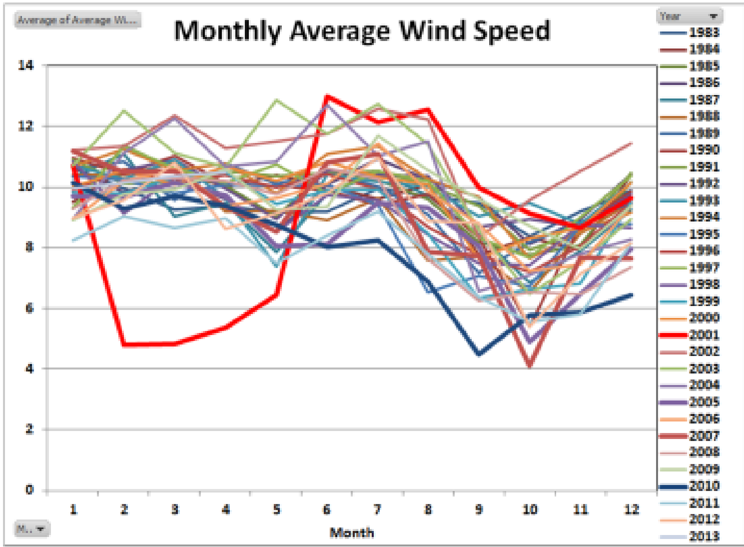
It is observed

- that the average monthly wind speed for all El Niño months in general are higher that all months and the months not being El Niño months
- that the average monthly wind speed for all El Niño months (13 out of 75) measured with the 50 m mast is ≈9% higher than the "not El Niño months"
- that the years 2007 – 2013 (mainly being based on the 50 m MET mast) have the lowest monthly wind speed average.

A further analyse of the 1983 – 2013 wind data in relation to the yearly average confirms this and is indicated in the graph below.



The average monthly wind speed for each of the years 1983-2013 is shown in the graphs below. The most predominating years with lowest monthly average (2001, 2005, 2007, and 2010) are bold highlighted.



It is observed that the year 2001 in particular has a wind distribution different from the other years. The reason for the very unusual 2001 data is most likely due to errors in the 10m data during this year.

The months Feb – May in 2001 have been eliminated in the further analyse since these wind data and belonging monthly energy production clearly not are correct.

The average monthly wind speed distribution over the years 1983- 2013 is shown beside.

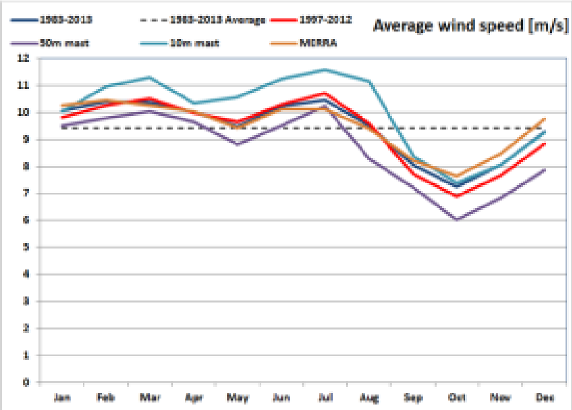
Hydroflow data has been made available by UMPE for the years 1997-2012 and thus constitutes the time window for the correlation and complementarity analyse based on the wind speed [m/s] and the hydroflow [m^3/s] data.

Consequently the years 1997 – 2012 have also been analysed in relation to the monthly average wind speed.

It is observed that the yearly avearge wind speed for the 1997-2013 decreases from 9,43 m/s to 9,33 m/s compared with full 1983- 2013 data serie.

Wind Speed Analyse

	1983-2013 Average [m/s]	Wind speed % of average	1997-2012 Average [m/s]
Jan	10,06	106,6%	9,81
Feb	10,39	110,1%	10,27
Mar	10,39	110,1%	10,52
Apr	10,01	106,1%	9,99
May	9,48	100,5%	9,65
Jun	10,24	108,5%	10,30
Jul	10,46	110,9%	10,70
Aug	9,52	100,9%	9,60
Sep	8,06	85,4%	7,71
Oct	7,26	77,0%	6,90
Nov	8,07	85,5%	7,66
Dec	9,28	98,3%	8,84
Year	**9,43**	**100,00%**	**9,33**
Max	10,46	111%	10,70
Min	7,26	77%	6,90

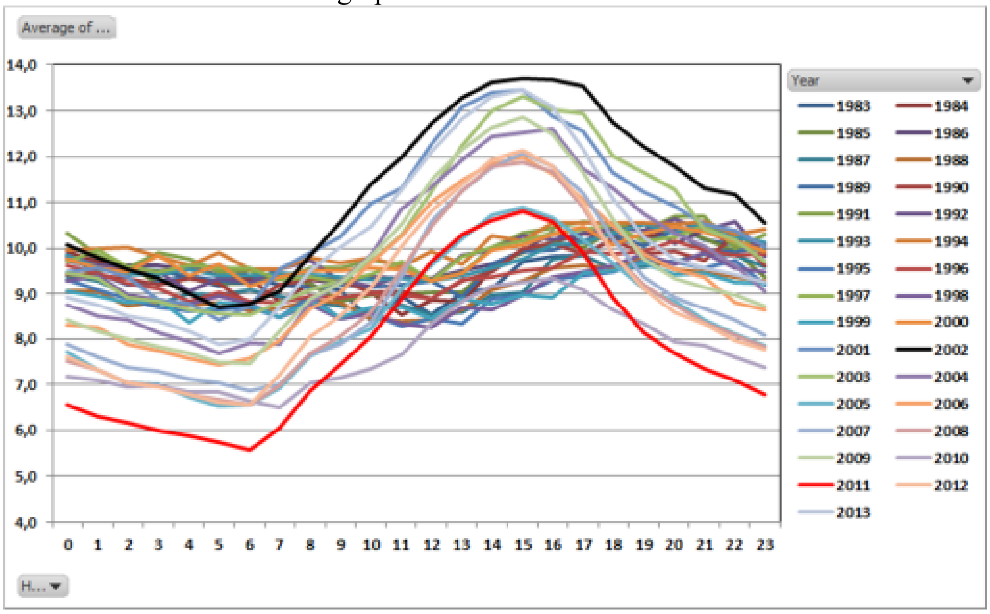


The monthly average distribution for the different scenarios and for all the years 1983- 2013 is shown beside. It is observed that the general trend in the monthly distribution over the year is the same.

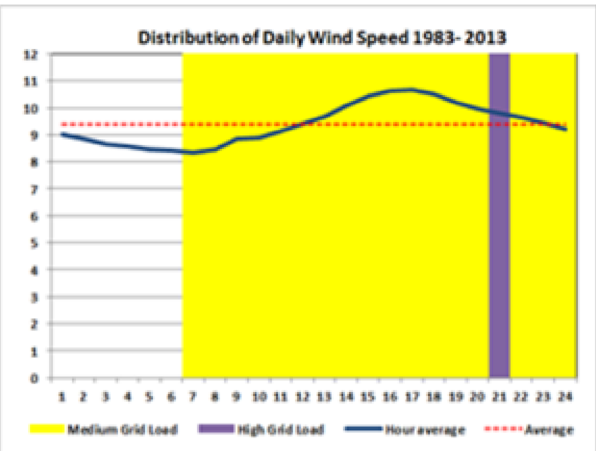
Above average: **Jan-Feb-Mar-Jul**
Below average: **May-Sep-Oct-Nov-Dec**

Above observations are relevant in the further analyse of the wind/hydro complementarity.

The wind data has also been analysed against the average daily distribution. The outcome is illustrated in the graph below:



It is observed that a significant variance for the different years exists with the extreme average 13.7 m/s between 15-17 hours in 2002 and the extreme minimum 5,6 m/s between 5-6 hour in 2011. It is noted that year 2002 and 2011 also represent the maximum and minimum yearly average wind speed.



The figure beside shows the distribution of the average wind speed during the day. (Yellow indicates medium grid load time span and purple indicates high grid load time span).

The wind/hydro complementarity study does not relate to the daily distribution of the energy production and will not be subject to any further studies.

However it shall be noticed that the daily wind speed in general has its highest values in the medium load demand block "13h-22 h" being counteracted by its lowest wind speed in the time span between "02h-10h". This indicates that the wind energy relatively will produce more during the medium and high grid load time span than during the low grid load time span.

5.3.3 Wind speed variation – conclusions

- ✓ *Dependency on wind turbine size*
  The average wind speed increases with height above ground and consequently for larger wind turbines with higher hub height.
  Yearly average: 1,3MW with hub height 60m (9,2m/s)→3,0MW with hub height 84 m (9,6m/s)

- ✓ *Seasonal behaviour of wind speed*
  The monthly average wind speed tends to be
  Above average: Jan-Feb-Mar-Jul
  Below average: May-Sep-Oct-Nov-Dec

- ✓ *Wind data set 1983-2013*
  The monthly average wind speed for 2007-2013 based on the 50m MET masts seems to be lower compared with the data compiled for 1983-2006 based on the 10m MET mast (2001-2006) and based on MERRA data for 1983-2000 This is considered to be a result of the actual long term variation of the wind speed over the years.

5.3.4 Compilation of Wind Energy 1983-2013

The wind/hydro complementarity will be based on the energy production for the wind vs. the hydro power plants being investigated.

This section outlines the assumptions taken and the methods applied for the computation of the wind energy production series. The basis for the wind energy production is established from the wind series through the years 1983-2013 as described in the previous section and raw production data (1 hour resolution) for the three wind farms located approximately at the same site.

- 400 MW "200 x 2.0 MW turbines"
- 400 MW "132 x 3.0 MW turbines"
- 19,5 MW "15 x 1,5 MW turbines"

All the wind farms are assumed to be located close to the present Jepirachi site where also the MET-mast data series have its origin.

The main analysis will focus on the 400 MW wind farm consisting of 200 x 2 MW turbine units with the same characteristics as assumed for the AEP calculation.

The wind energy production 1 hour raw data series is computed from wind data series recalculated to hub height by the actual power curve and reduced by the wake loss impact on the wind speed.

Thus a 1h data series for the wind farm energy production is established and the net energy production from the wind farm can be computed by:

Gross energy production from all WTGs
(Wake losses & 2% power curve losses considered)
- Power losses in 33 kV distribution cables within the wind farm
- Power losses in the 0,69/33 kV transformers at the wind turbines
- Power losses in the 33/220 kV transformer at the wind farm SS
Energy supply to 230 kV transmission line
- Power losses in the 230 kV transmission line
<u>Energy supply to the grid at the delivery point</u>

The power losses are comprised by:

- No-load losses (being constant when the equipment is connected to the network)

- Full load losses
  Depend on the actual load on the equipment
  - Zero when no load
  - Maximum at full load
  - Proportional with the load^2 in between full and no-load (thus insignificant a low load but significant at high load)

The net energy production have been calculated for each hour taking above power losses into consideration and with the magnitude of power losses indicated in the table below and concluded from the technical power system studies in the "Study Report 01: Power System Technical Analysis – Neplan".

Wind Fark Full Production (200x2MW) : 400 MW

Power Losses & Consumption	Full Production			No load		
33 kV cables		2,19	MW		0,01	MW
33/220 kV transformers		1,08	MW		0,32	MW
Losse WT transformers*)		2,6	MW		0,6	MW
Consumption WT (8kW/each) **)		0	MW		1,6	MW
Consumption 33/220 kV substation		0,1	MW		0,1	MW
Losses at wind park substation	1,5%	5,97	MW	0,7%	2,63	MW
220 kV Transmission line to Cuestecita		16,6	MW			MW
Total losses	5,6%	22,5	MW	0,7%	2,6	MW

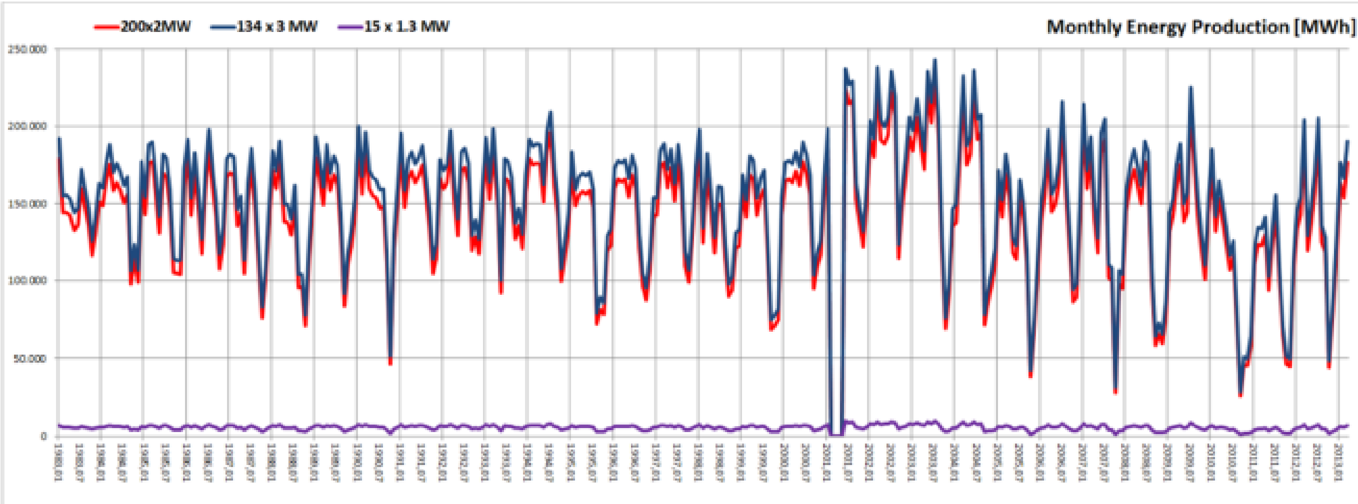
*) Wind turbines power deliverey is at LV side of the .69/33 kV WG Transformer
**) WT's own consumption is considered in the power curve.

Wind Speed Analyse	1983-2013 Average [m/s]	Wind speed % of average	Availability assumed [%]
Jan	10,06	106,6%	98,0%
Feb	10,39	110,1%	98,0%
Mar	10,39	110,1%	98,0%
Apr	10,01	106,1%	98,0%
May	9,48	100,5%	94,0%
Jun	10,24	108,5%	98,0%
Jul	10,46	110,9%	98,0%
Aug	9,52	100,9%	94,0%
Sep	8,06	85,4%	94,0%
Oct	7,26	77,0%	94,0%
Nov	8,07	85,5%	94,0%
Dec	9,28	98,3%	94,0%
Year	**9,43**	**100,00%**	**96,00%**
Max	10,46	111%	98%
Min	7,26	77%	94%

Further the availability of the wind farm shall be considered to take into account the outages caused by either planned maintenance or fault conditions/repair either in the wind turbines and the power grid.

The AEP calculation assumes an overall yearly availability 96% for the wind farms being adopted for the wind/hydro complementarity analyse. The availability is differentiated over the months in relation to the % average wind speed since the planned maintenance work should be planned in the months were lowest wind occur (May-Aug-Sep-Oct-Nov-Dec).

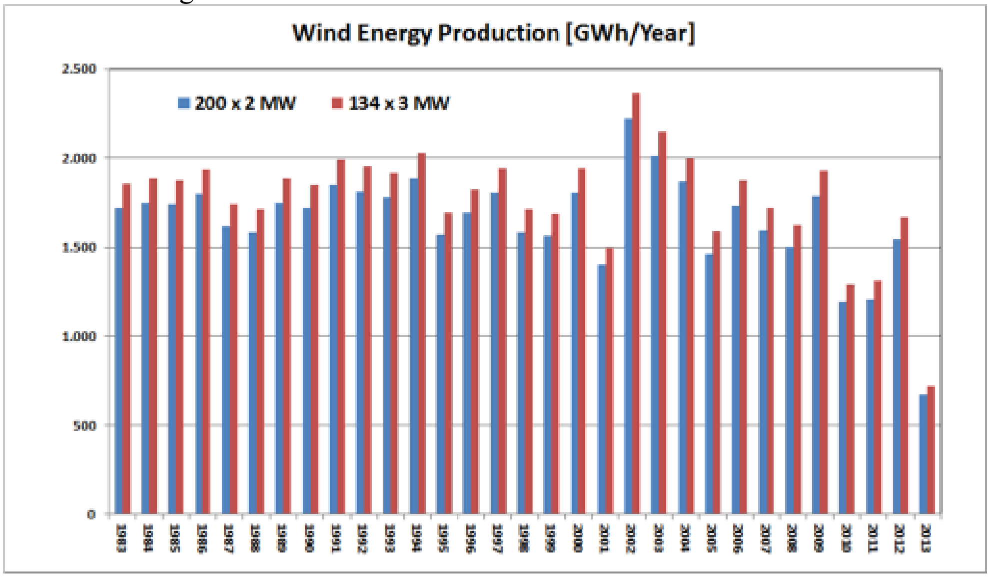
The monthly average for the three wind farms during the months Jan83-Mar13 are shown in the graph below.



A significant flucturation of the monthly energy production [MWh] is observed with the extreme minimums in 2001 and 2007. (Feb-May 2001 are eliminated due to the incorrect winddata measurements).

	15x1,3MW	200x2,0MW	134x3,0MW
Installed capacity	*19,5 MW*	*400 MW*	*402 MW*
Effective net capacity	*17,4 MW*	*361,6 MW*	*373,4 MW*
Monthly Energy Production			
Maximum	9.578 MWh	229.781 MWh	242.783 MWh
Minimum	947 MWh	25.643 MWh	28.581 MWh
Average	5.603 MWh	142.199 MWh	153.153MWh
Standard Deviation	1.583 MWh 28,3%	37.794 MWh 26,6%	39.663 MWh 25,9%

The yearly energy production for each of the years for the two large windfarms is shown in the figure below.



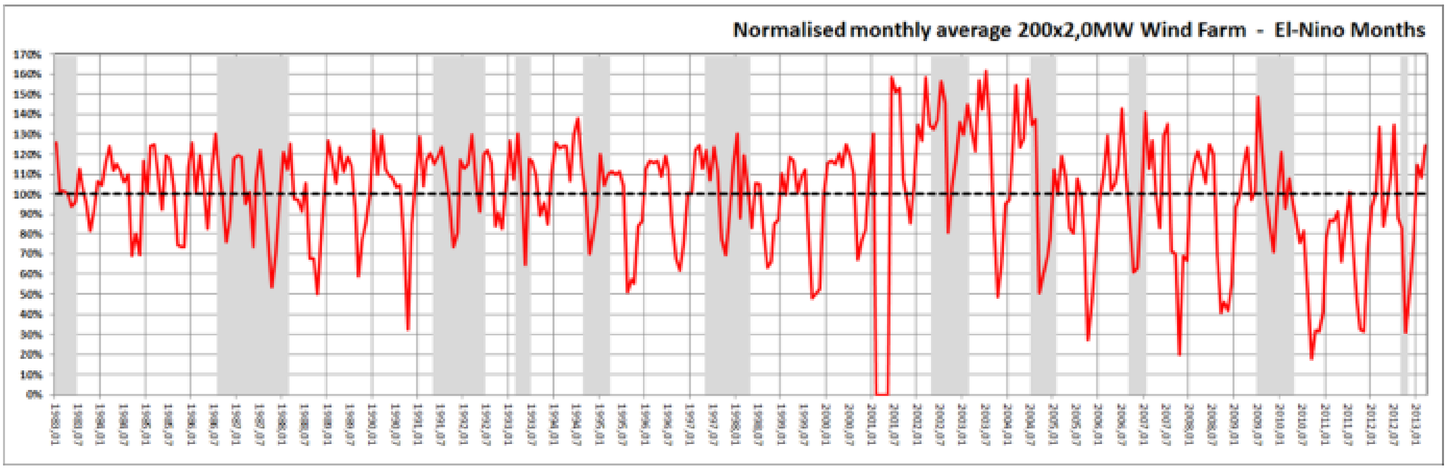
In particular the low energy production in the years 2010 and 2011 is noticed being in compliance with the low yearly average wind speed measured particular for these two years. (Year 2001 should have been higher if Feb-May is included).

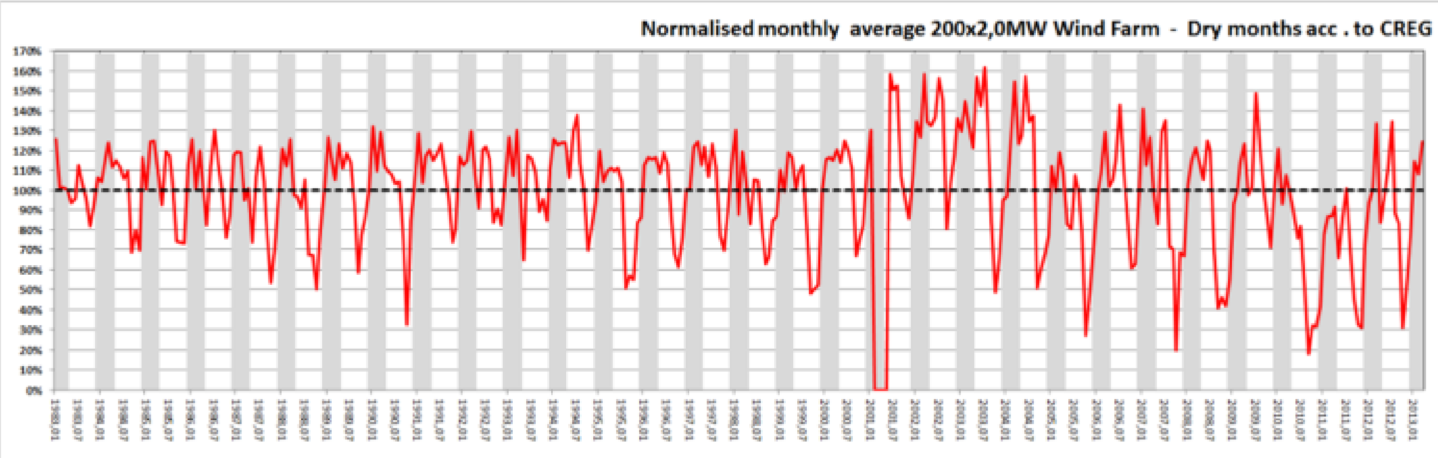
A simple statistic analysis of the yearly energy production supplied to the grid at the delivery point in the Cuestecita station through a 131 km 230 kV transmission line for the years 1983 – 2012 is shown below

Yearly Energy Production [GWh]		
	200x2,0MW	134x3,0MW
Maximum	2.200	2.365
Minimum	1.191	1.293
Average	1.685	1.815
Standard Deviation	209 12,4%	219 12,1%

A very first and general assessment of the wind energy production of the two large 400MW/402MW wind farms in relation to the El-Niño phenomena and the dry months "Dec-Jan-Feb-Mar-Apr" (*being defined by CREG ref. 05)* can be made from the two following figures.

The figures illustrate the normalised monthly energy production (actual production/average monthly production) together with the El-Niño months indicated in grey.





An analysis of the monthly energy production for the 200x2,0MW wind farm gives the statistics tabled below.

200x2,0MW – (1983-2013)	All months	CREG		El-Niño	
	---	**Dry**	**Wet**	**Dry**	**Wet**
Maximum	**229.781 MWh**	224.853 MWh	**229.781 MWh**	222.209 MWh	**229.781 MWh**
Minimum	25.643 MWh	**58.544 MWh**	25.643 MWh	**43.953 MWh**	25.643 MWh
Average	142.199MWh	**157.289 MWh**	131.368 MWh	**146.158 MWh**	140.754MWh
Standard Deviation	37.794 MWh 26,6%	24.195 MWh 15,4%	41.866 MWh 31,9%	34.148 MWh 23,4%	38.941 MWh 27,7%

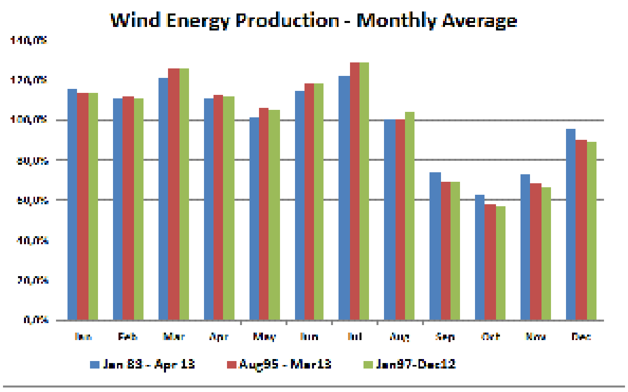
It is observed that the

1 The monthly energy production has it highest average in the CREG defined dry months

2 The minimum monthly energy production in the dry months are significant higher than the wet months

3 The maximum monthly energy production occur in the wet months

From above the assumption about a tendency with higher wind energy production during the dry months compared with the wet months generally is justified. This will be analysed further in the following sections of this report.



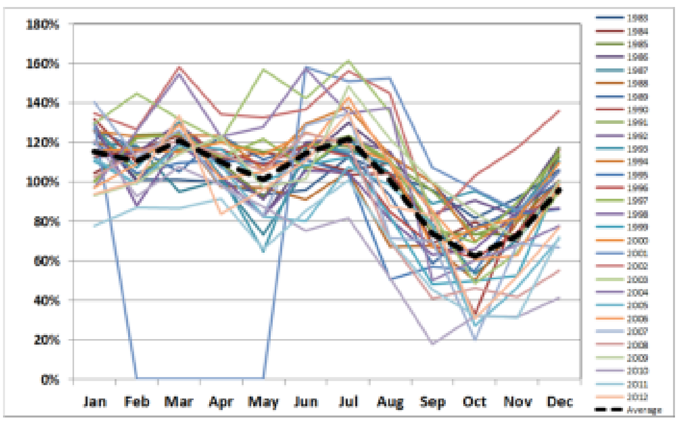
An analysis of the 200x2,0 MW wind farm in relation to the average monthly production distributed over the year for various time spans has also been performed. The graph beside and the table shown below outlines the monthly average of the wind energy production in the time spans:

- Jan 83 – Apr 13 "all months with wind data"
- Aug 95 – Mar13 "months with hydro production data"
- Jan 97 – Dec 12 "months with hydro inflow data"

It is observed that the monthly average only appears to fluctuate insignificant when the different time spans are considered.

Wind Energy Production Analyse						
	Jan 83 - Apr 13		Jan97-Dec12		Aug95 - Mar13	
	Average [MWh]		Average [MWh]		Average [MWh]	
Jan	164.156	115,4%	158.516	113,1%	158.842	113,5%
Feb	157.156	110,5%	155.334	110,8%	155.862	111,3%
Mar	172.139	121,0%	176.203	125,7%	175.512	125,4%
Apr	156.996	110,4%	156.432	111,6%	157.989	112,8%
May	143.548	100,9%	147.767	105,4%	148.178	105,8%
Jun	162.994	114,6%	165.438	118,0%	165.636	118,3%
Jul	173.439	121,9%	180.721	128,9%	179.523	128,2%
Aug	143.046	100,6%	145.445	103,8%	139.997	100,0%
Sep	104.746	73,6%	97.581	69,6%	96.583	69,0%
Oct	88.847	62,5%	80.357	57,3%	80.653	57,6%
Nov	103.364	72,7%	93.343	66,6%	95.484	68,2%
Dec	136.313	95,8%	125.012	89,2%	125.857	89,9%
Year	**142.229**	**100,0%**	**140.179**	**100,0%**	**140.010**	**100,0%**

The numbers in the above table will be used in the complementarity analysis against the hydro plant energy production.



The normalised distribution of the average energy production by the 200x2,0 MW wind farm is illustrated beside for each year in 1983-2013 (March month inclusive). The average of all years is also indicated.

It is observed that a general trend in the monthly distribution over the year is:

Above average: **Jan→Jul**
Below average: **Aug →Dec**

The Feb-May months in 2001 are not included in the calculations

5.3.5 Wind production profile, Conclusions

- ✓ *Seasonal behaviour of wind energy production*
  The monthly average wind speed tends to be
  Above average: Jan→Jul
  Below average: Aug→Dec

- ✓ *El-Niño & CREG dry months*
  The monthly average wind energy production is larger in the dry months than the wet months.

  The average monthly energy production is larger in the CREG dry months compared with the El-Niño months.

  The maximum average wind energy production occurs in July being one of the wet months

From above the assumption about a tendency with higher wind energy production during the dry months compared with the wet months is justified for the Northern La Guajira province.

5.4 Hydro data compilation

The wind/hydro complementarity analysis shall be based on energy production series from production plans meeting the following criteria:

- Production data from the same time period shall be analysed

- Production capacity for the plants shall be the same for all years investigated

The sections below aims at identifying a suitable selection of existing hydro power plants fulfilling above criteria's and applicable in the continued analyse.

5.4.1 Hydro data basis

A number of data files have been provided by UMPE and constitute the basis for the hydro analysis.

- Genera Real Hidrau Hora por central.txt
- Aportes Rios Caudal dia.txt
- Centrales_embalses_rios.xlsx
- Features of hydro and small power plants.xlsx

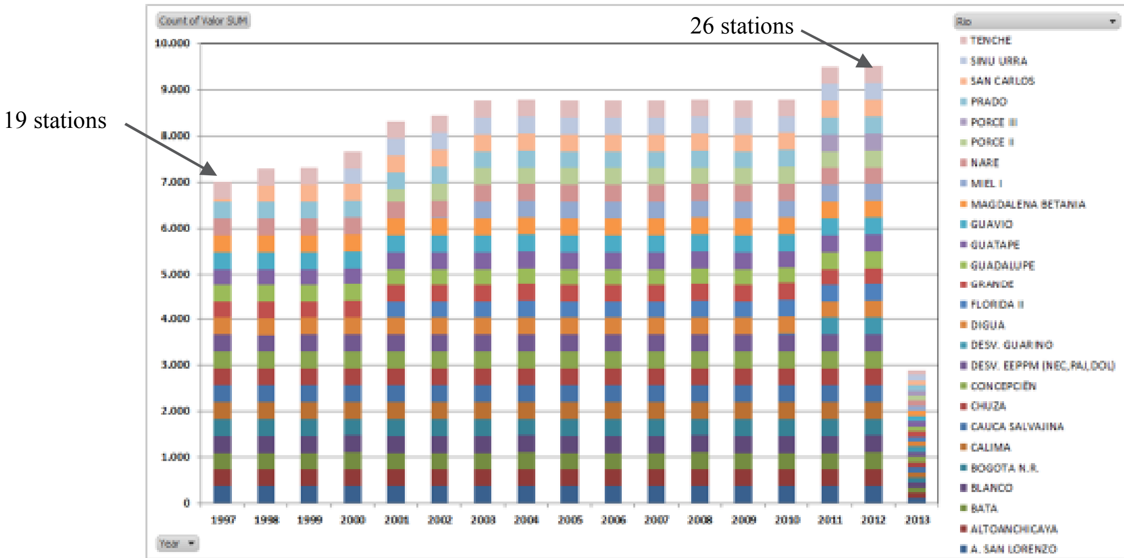
5.4.2 Data processing

5.4.2.1 Data processing – river discharges

The monthly distribution of the water flow [m3/s] has been reported in the text file "Aportes Rios Caudal dia.txt". It contains measured water flow in a large number of rivers in Colombia, thus representing the fluctuation of a possible energy production during the years and months investigated.

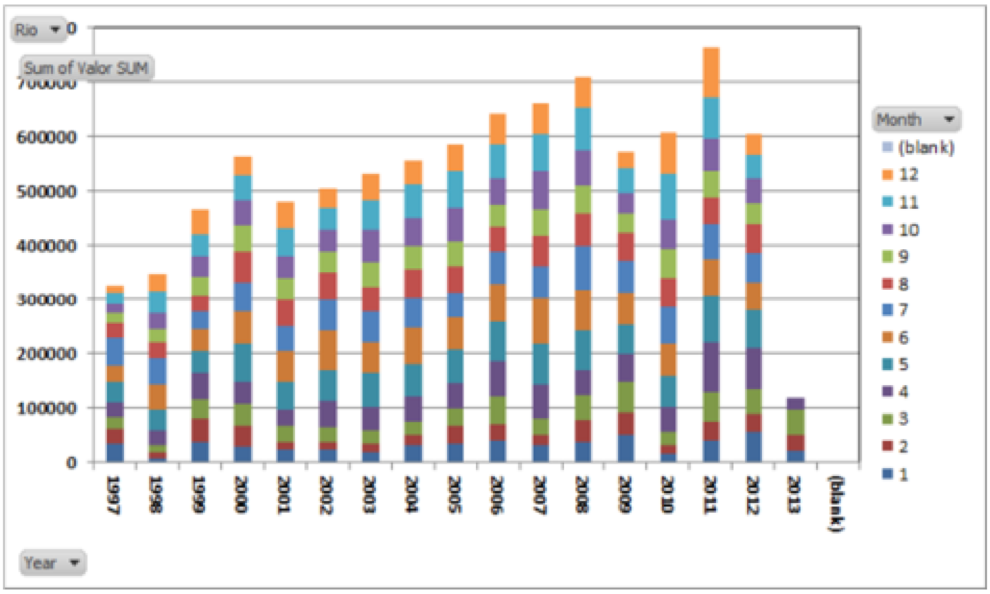
River Discharge "All Colombian Rivers"

The wind/hydro complementarity analysis implemented for the wind speed vs. river inflow is based on all the rivers measured and will not focus on single or selected rivers.



The figure above identifies the rivers reported and the count of measurements taken over the years. It is noticed that the number of measurement's increase from approximately 7000 in 1997 to 9500 in 2012 (approximately 36% over 15 years equal to app. 2% increase each year).

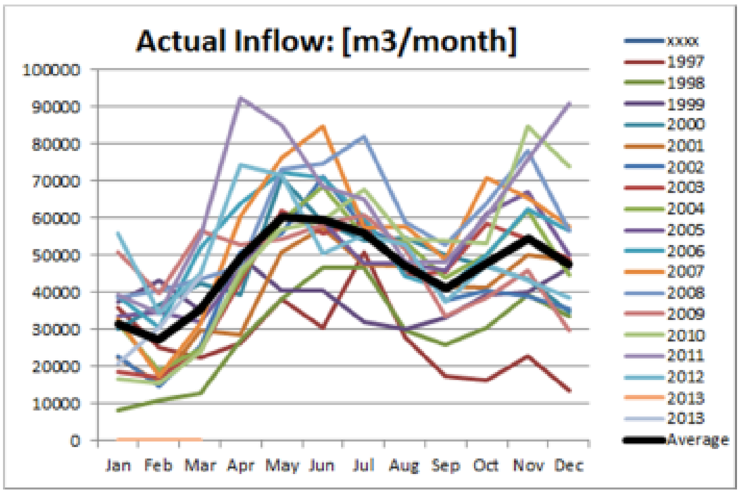
The "water in-flow m^3 data base" made available by UMPE includes data in the time span from Jan 1997 to Mar 2013. The data has it origin from 26 different rivers in Colombia and from an increasing number of measurement stations as it appears from the figure below.



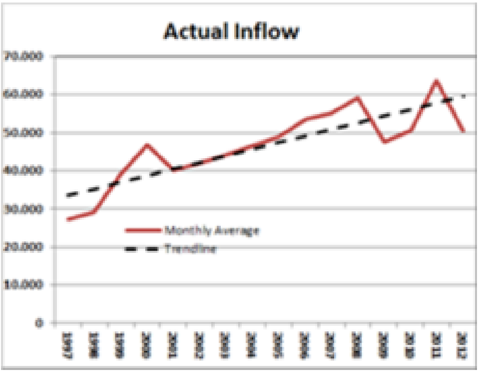
The total river discharge for all years is shown above also indicates an increasing tendency. The river inflow depends on the actual rain in the years and the number of measurement stations as well. It is observed that 2009, 2010, and 2012 seems to be years with low inflow.

The wind/hydro complementarity will be done on monthly basis. Consequently, an overall monthly average for the years needs to be determined to calculate the normalised monthly distribution for comparison with the wind speed

The monthly river discharge distribution over the months during Jan 1997 – March 2013 is shown in the figure below being based on the raw-data included in the files made available.

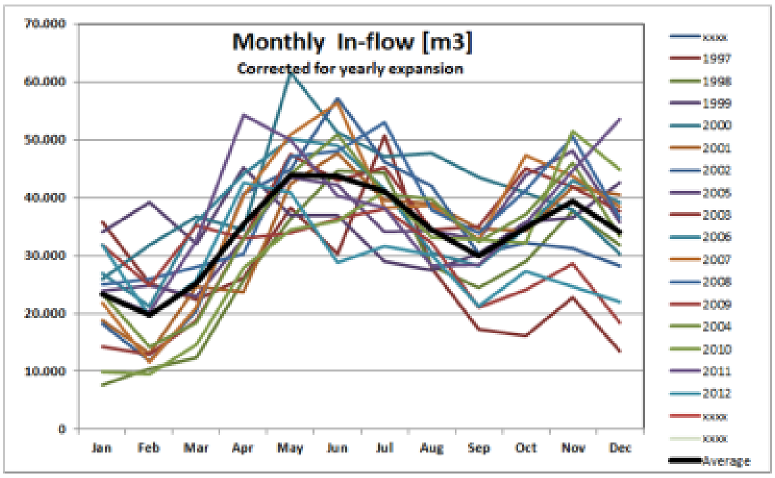


A simple monthly average can be calculated from the raw data as 46.264 m3 when all years 1997-2013 are considered. This number must be corrected when used as the base for the normalised monthly behaviour of the hydro inflow since the actual annual hydro inflow increases significantly over the years 1997-2013. (Presumable effected by the increasing measuring stations or eventual climate changes that not can be accounted in for this study). Thus the actual monthly average as well will increase over the years as it is indicated in the graph below.



Consequently the corrected monthly average of the inflow is computed by correcting the actual monthly hydro inflow in each year by the 5% increase. (It is simply being computed from the trend line for the annual inflow).

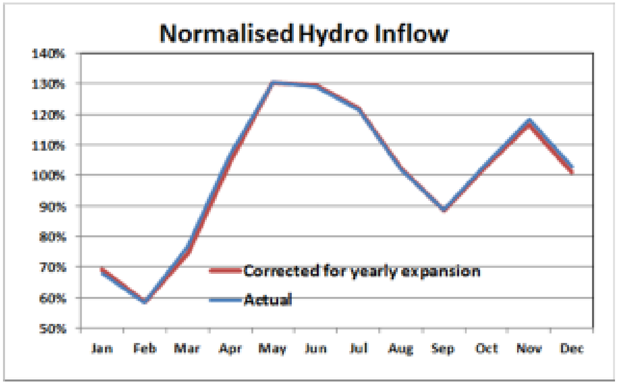
The monthly in-flow in the years 1997-2013 being corrected for the yearly increase of the measurements stations is shown below.



The overall (whole Colombian pool of Hydro power plants) normalised monthly average of the in-flow distribution expressed in % of the monthly average is listed in the table and indicated in the graph below.

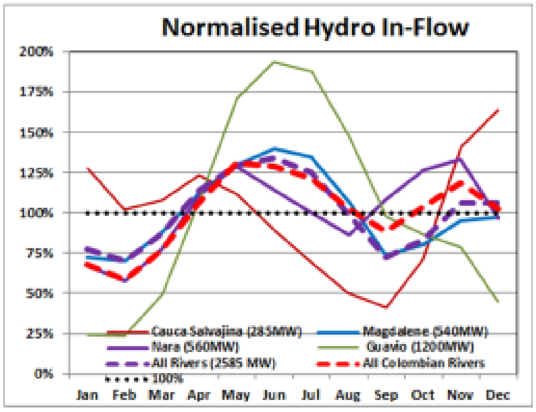
Hydro inflow [m3]												Corrected for yearly expansion
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1997	35.857	25.160	22.409	26.122	38.310	30.348	50.773	27.871	17.269	16.205	22.782	13.453
1998	7.700	10.504	12.283	25.647	36.205	44.463	44.178	28.192	24.461	28.938	37.558	31.787
1999	33.941	38.995	31.802	45.048	36.708	36.711	28.879	27.299	30.173	35.579	36.459	42.326
2000	25.894	31.608	36.542	34.189	61.385	51.038	46.763	47.434	43.283	40.712	37.692	30.161
2001	18.668	12.968	24.522	23.597	42.028	47.403	39.220	38.795	34.361	34.048	41.573	40.176
2002	17.979	11.729	20.353	40.392	44.412	56.617	45.689	41.633	30.117	31.984	30.980	28.044
2003	14.181	12.877	18.563	32.580	47.121	42.477	44.838	34.036	34.597	44.600	41.445	37.384
2004	23.073	14.017	18.193	32.504	43.564	50.253	40.307	39.371	32.083	36.695	45.460	32.901
2005	23.596	24.472	22.588	32.601	43.088	41.657	33.673	33.862	32.286	43.363	47.401	35.337
2006	26.617	20.883	35.387	43.441	49.408	48.296	40.862	30.097	27.829	34.150	42.467	38.670
2007	21.498	11.360	20.842	39.845	50.182	55.635	37.662	38.031	32.268	46.623	43.101	37.894
2008	24.565	25.666	27.697	29.865	46.454	47.411	52.237	37.397	33.491	40.728	49.807	35.924
2009	31.271	24.527	34.769	32.463	33.467	35.721	37.491	31.697	20.659	23.724	28.159	18.203
2010	9.838	9.300	14.401	27.351	33.996	35.459	40.477	32.517	32.241	31.678	50.621	44.173
2011	22.863	19.956	31.945	53.404	49.133	39.559	37.617	27.820	27.959	34.996	43.986	52.573
2012	31.321	19.185	25.335	41.776	40.142	28.309	31.076	29.668	20.934	26.718	24.151	21.596
2013				[redacted]								
Average	23.054	19.575	24.852	35.052	43.475	43.210	40.734	34.108	29.626	34.421	38.978	33.787
										Average	33.406 m3/mth	
Normalised average	*69,0%*	*58,6%*	*74,4%*	*104,9%*	*130,1%*	*129,3%*	*121,9%*	*102,1%*	*88,7%*	*103,0%*	*116,7%*	*101,1%*

This above % distribution will be used for the later complementarity analyse in relation to the wind speed. It is observed that the impact of the correction not is significant as illustrated in the figure below.



River Discharge "Actual Rivers"

The Hydro generating plants selected for the study (addressed in a later section of the report) show deviating behaviour in the average monthly production for all Colombian rivers and the water in-flow for the actual rivers. Consequently an analysis of the water in-flow reported for each of the relevant rivers has been implemented and is summarised below.



Nara, Magdalene and Guavio rivers correlate quite good with the all Colombian rivers (Correlation factor above 0,8).

The Cauca Salvajnia River has a significant different behaviour with normalised monthly hydro in-flow above 100% in Jan-Feb-Mar. (This is not the case for the other rivers). The figures for Apr→Sep also are significant lower than the other rivers.
The Cauca Salvajnia River hydro in-flow does not correlate with the other rivers. This is verified with a calculated correlation factor to all Colombian rivers (-0,02) practically equal to zero.

The Gavio river has maximum 200% and minimum 25% normalised water-in-flow that is significant more fluctuating compared with the other rivers.

Normalised Monthly Average Hydro In-Flow

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Coor. Factor
All Colombian Rivers	67,9%	58,4%	76,5%	106,9%	130,6%	129,0%	121,3%	102,1%	88,7%	103,9%	118,2%	102,7%	1,00
Cauca Salvajina (285MW)	127,3%	101,7%	108,0%	123,5%	111,9%	89,2%	69,2%	49,7%	41,1%	71,3%	141,0%	163,8%	-0,02
Magdalene (540MW)	72,2%	70,2%	87,6%	112,8%	129,2%	139,9%	134,3%	107,1%	73,6%	80,7%	95,0%	97,4%	0,85
Nara (560MW)	67,0%	57,8%	77,1%	111,0%	128,9%	113,9%	100,2%	86,5%	108,2%	126,3%	133,0%	96,3%	0,84
Guavio (1200MW)	24,4%	23,9%	49,1%	106,9%	170,8%	193,3%	187,8%	148,2%	97,8%	87,0%	78,7%	44,7%	0,83
All Rivers (2585 MW)	77,2%	70,3%	87,2%	113,9%	129,3%	134,1%	124,8%	98,6%	72,7%	83,6%	106,3%	106,2%	0,89

5.4.3 Data analyses – hydro energy production

5.4.3.1 Hydro Power Plants - Selection

The production from hydro power generator plants in Colombia has been reported in the time span from Jan 1995 to Mar 2013 on an hourly basis. A total list of hydro generating units in Colombia is illustrated beside:

Hydro Generator Plants	
Hydro Production Plant	MW
ALBAN (ALTO Y BAJO ANCHICAYA) GENERADOR	429
AMERICA GENERADOR	0,41
ASNAZU GENERADOR	0,45
AYURA GENERADOR	18
BELLO GENERADOR	0,35
MENOR BELMONTE	18
MENOR BAYONA	0,6
COCONUCO	4,5
BETANIA GENERADOR	540
CHIVOR GENERADOR	1000
CALIMA GENERADOR	132
CAMPESTRE GENERADOR EPM	0,87
MENOR CAMPESTRE	0,7
CASCADA GENERADOR	3
ESMERALDA GENERADOR	30
MENOR GUACAICA	0,9
GUATAPE GENERADOR	560
GUATRON GENERADOR	512
GUAVIO GENERADOR	1200
INSULA GENERADOR	19
MENOR INTERMEDIA	1
JAGUAS GENERADOR	170
MENOR LIBARE (VENTORRILLO)	5,1
EL PALO GENERADOR	1,44
LATASAJERA GENERADOR	306
MENOR MUNICIPAL 1 Y 2	2
MONDOMO GENERADOR	0,75
MANANTIALES GENERADOR	3,15
NIMA 1 GENERADOR	6,7
NIQUIA GENERADOR	19
NUTIBARA GENERADOR	0,75
PIEDRAS BLANCAS GENERADOR	5
PARAISO GUACA GENERA	600
PALMAS 1 GENERADOR	15
PLAYAS GENERADOR	201
COGENERADOR PROENCA	0
PRADO 4 GENERADOR	5
PRADO GENERADOR	46
RIO CALI 1 GENERADOR	1,8
RIOFRIO I GENERADOR	1,69
RIOFRIO II GENERADOR	10
RIOGRANDE1 GENERADOR	0,3
RIOGRANDE	19
RUMOR GENERADOR	9,6
RIOMAYO GENERADOR	19,8
RIO PIEDRAS GENERADOR	19,9
SAJANDI GENERADOR	3,2
SILVIA GENERADOR	0,38
SALVAJINA GENERADOR	285
MENOR SAN CANCIO 1 Y 2	2
SANCARLOS GENERADOR	1240
SANFRANCISCO GENERA.	135
MENOR UNIÓN	0,7
URRA	338

This study report considers generating plants selected by UPME. Six units were appointed by UPME.

The two ALBAN & URRA generating units were eliminated from the list since production data for these units not are reported for all months between 1995 and 2013.

Consequently the analyse of the hydro production is based on the units listed below

- SALVAJIA 285 MW
  River: Cauca Saljina

- BETANIA 540 MW
  River: Magdalene Betania

- GUATAPE 560 MW
  River: Nara

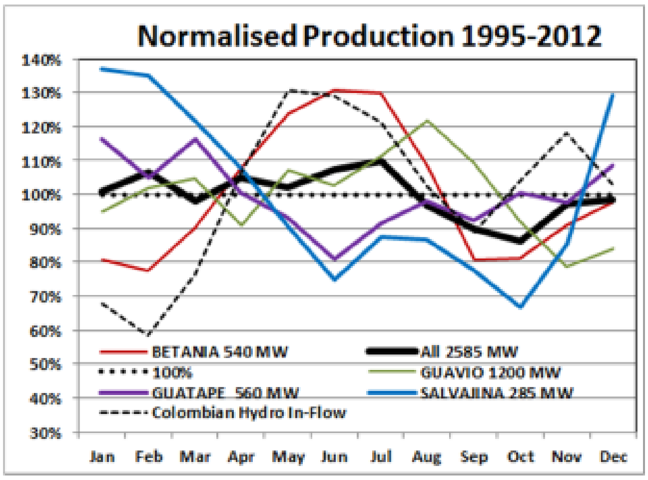
- GUAVIO 1200 MW
  River: Guavio

- All units pooled together 2585 MW
  River: "All four rivers mentioned above"

5.4.3.2 Hydro units - actual production

The actual production reported for each of the hydro power plants have been analysed on a monthly basis. The table and figure below show the normalised monthly energy production for each of the units and all units pooled together based on the Aug 95-Mar14 time interval. (Reference is given to Appendix A-E where more details can be found for each generation unit).

The normalised monthly energy production for each of the selected hydro power plants is shown below. The normalised hydro in-flow for all Colombian rivers is also indicated for comparison.



A number of observations are listed below:

a) No consistent or clear relation between the production and the hydro in-flow seems to exist for the power plants selected

b) The normalised actual hydro production for each of the power plants does not show same behaviour

c) The 285MW & 560 MW units have normalised production less than 100% in May-Jun-Jul. This is in contradiction with the 1200MW & 540MW units and does not correlate with the hydro in-flow for all Colombian rivers).

d) Only the 540 MW Betania hydro plant seems to correlate with the hydro inflow for all Colombian rivers

To complement above observations the normalised monthly in-flow for each of the actual rivers and the correlation factor with the production has been calculated. This correlation factors are shown in the table below.

Normalised Monthly Hydro Production												Aug95 - Mar 13	Correlation Factor Prod. vs. In-flow	
Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Whole Colombia	Actual River
SALVAJINA 285 MW	136,90%	134,97%	121,44%	107,79%	90,74%	74,86%	87,58%	86,54%	77,88%	66,63%	85,30%	129,37%	-0,69	0,61
BETANIA 540 MW	80,85%	77,64%	90,27%	107,81%	123,92%	130,77%	129,88%	108,18%	80,84%	81,02%	90,82%	98,00%	0,80	0,99
GUATAPE 560 MW	116,36%	104,82%	116,15%	100,63%	92,97%	80,76%	91,69%	98,05%	92,20%	100,33%	97,58%	108,46%	-0,74	-0,62
GUAVIO 1200 MW	95,03%	101,87%	104,68%	91,05%	107,20%	102,61%	111,37%	121,83%	109,16%	92,14%	78,90%	84,15%	-0,02	0,50
All 2585 MW	100,79%	106,54%	98,13%	105,07%	101,99%	107,49%	109,94%	96,70%	89,77%	86,43%	97,14%	98,46%	0,15	0,53
Colombian Hydro In-Flow	67,9%	58,4%	76,5%	106,9%	130,6%	129,0%	121,3%	102,1%	88,7%	103,9%	118,2%	102,7%	1,00	

Observations:

- The Betania 540 MW unit production has an almost 100% fit with the hydro in-flow reported for the actual Magdalene River.

- The correlation between production and hydro inflow is improved significantly for the Salvajina (285 MW) and Guavio (1200 MW) units when the actual river in-flow data are used.

- The correlation between production and hydro inflow for the Guatape (560MW) unit is not improved when the actual river in-flow data is used.

The missing correlation between the nominal actual production and the normalised hydro-in flow is not investigated further, since the units are selected by UPME.

However, the bullets below indicate some possible factors that could explain the deviation from the expected correlation between the water-in-flow for the selected hydro power plants.

- <u>The differences in the timelines</u>. Hydro inflow data are not made available for Aug 97 – Dec 96 thus approximately 2 years of hydro data are missing.

- <u>The influence of dams and reservoirs</u> that will impact the energy production distribution over the years and at a later time than the actual occurrence of the in-flow to the rivers.

Above tabled normalised monthly energy production will be used for the complementarity analyse of the wind and hydro energy production.

5.5 Complementarity analysis

The complementarity analysis aims at identifying months where the normalised windspeed is above 100% and the river inflow is below 100%. (The same analysis will be done for the wind and hydro energy production).

These months will be ***"favourable wind months"***.

5.5.1 Hydro inflow vs wind speed– all years/months

5.5.1.1 Based on hydro inflow, All Colombian Rivers

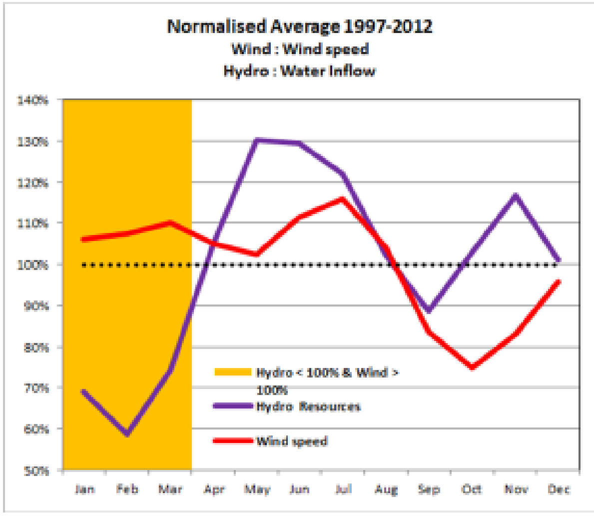
<u>Wind speed & Hydro inflow – monthly average 1995-2012</u>

The normalised wind speed and river in-flow for the 1997-2012 years are compared in the table below being based on the monthly average for all years considered.

All Colombian Rivers													
Monthly Average Wind Speed [m/s] vs. Hydro Inlet [m3]												Jan97-Dec12	Correlation
Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
Hydro	*67,9%*	*58,4%*	*76,5%*	*106,9%*	*130,6%*	*129,0%*	*121,3%*	*102,1%*	*88,7%*	*103,9%*	*118,2%*	*102,7%*	-0,18
Wind	106,6%	110,1%	110,1%	106,1%	100,5%	108,5%	110,9%	100,9%	85,4%	77,0%	85,5%	98,3%	
Hydro < 100% & Wind > 100%	Yes	Yes	Yes	No	No	No	No	No	No	No	No	No	

The correlation coeficient for the two data sets covering Jan95-Dec12 is calculated to -0.18 indicating an inverse correlation.

The figure below shows that the normalised wind speed is above 100% and the river inflow is below 100% in three months Jan-Feb-Mar.



From above it is concluded that the wind resources have a tendency to be higher during the months when the water resources are lowest. This in particular relates to Jan-Mar being “favourable wind months”.

Oct-Nov on the contrary seems to have the senario with normalised water ressources relatively higher than the normalised wind ressources.

It is observed that the normalised water in-flow in Dec and Apr are above 100% being in contradition with the CREG definition of the dry months that also includes this month.

The findings and conclusions above are based on nomalised monthly wind speed and hydro inflow calculated from the average over the whole timespan.

__Wind speed & Hydro inflow – Occurrence based on monthly average each year__

The actual distribution of favourable wind months for the 1997-2012 timespan (when the avearage for each year is used) is illustrated in the table below.

Distribution of favorable wind months

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	
Jan		FWM	FWM	FWM		FWM	FWM		FWM		FWM	FWM		FWM	FWM			10	59%
Feb	FWM	FWM		FWM		FWM	FWM	FWM	FWM	FWM	FWM	FWM	FWM	FWM	FWM	FWM		14	82%
Mar	FWM	FWM	FWM	FWM		FWM	FWM	FWM	FWM	FWM	FWM	FWM		FWM	FWM	FWM		14	82%
Apr	FWM	FWM		FWM			FWM	FWM	FWM			FWM		FWM				8	50%
May																		0	0%
Jun																FWM		1	6%
Jul			FWM						FWM									2	13%
Aug									FWM	FWM					FWM			3	19%
Sep																		0	0%
Oct																		0	0%
Nov																		0	0%
Dec	FWM			FWM		FWM												3	19%
																		55	28%

The table supports the general trend with favourable wind months occuring in Jan-Feb-Mar possible also in Apr. and to a less extent Dec. as well. The occurence of El-Niño months is also indicated (marked in yellow) and the CREG dry months (marked in orange).

No interrelation between the El-Niño months and the “favourable wind months” is observed. A clear coincident between the CREG dry months and the “favourable wind months” is verified.

It is also observed that not all the favourable wind months (Jan-Feb-Mar-“Apr” occur in all years.

5.5.1.2 Based on hydro inflow, Actual Rivers

The occurrence of favourable wind months when comparing the normalised wind speed with the normalised hydro inflow based on the actual river where the selected power plants are located is show in the table below.

Actual River for each selected Hydro Generating Plant													
Normalised Monthly Average Hydro In-Flow vs. Wind Speed													Coor. Factor
Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
Cauca Salvajina (285MW)	127,3%	101,7%	108,0%	123,5%	111,9%	89,2%	69,2%	49,7%	41,1%	71,3%	141,0%	163,8%	-0,02
Hydro < 100% & Wind > 100%	No	No	No	No	No	Yes	Yes	Yes	No	No	No	No	
Magdalene (540MW)	72,2%	70,2%	87,6%	112,8%	129,2%	139,9%	134,3%	107,1%	73,6%	80,7%	95,0%	97,4%	0,85
Hydro < 100% & Wind > 100%	Yes	Yes	Yes	No	No	No	No	No	No	No	No	No	
Nara (560MW)	67,0%	57,8%	77,1%	111,0%	128,9%	113,9%	100,2%	86,5%	108,2%	126,3%	133,0%	96,3%	0,84
Hydro < 100% & Wind > 100%	Yes	Yes	Yes	No	No	No	No	Yes	No	No	No	No	
Guavio (1200MW)	24,4%	23,9%	49,1%	106,9%	170,8%	193,3%	187,8%	148,2%	97,8%	87,0%	78,7%	44,7%	0,83
Hydro < 100% & Wind > 100%	Yes	Yes	Yes	No	No	No	No	No	No	No	No	No	
All Rivers (2585 MW)	77,2%	70,3%	87,2%	113,9%	129,3%	134,1%	124,8%	98,6%	72,7%	83,6%	106,3%	106,2%	0,89
Hydro < 100% & Wind > 100%	Yes	Yes	Yes	No	No	No	No	Yes	No	No	No	No	
All Colombian Rivers	67,9%	58,4%	76,5%	106,9%	130,6%	129,0%	121,3%	102,1%	88,7%	103,9%	118,2%	102,7%	1,00
Hydro < 100% & Wind > 100%	Yes	Yes	Yes	No	No	No	No	No	No	No	No	No	
Wind	*106,6%*	*110,1%*	*110,1%*	*106,1%*	*100,5%*	*108,5%*	*110,9%*	*100,9%*	*85,4%*	*77,0%*	*85,5%*	*98,3%*	

It is observed that

- Jan-Feb-Mar monhts being favorable wind months are supported by the Magdalene, Nara and Guvio River normalised inflow.
- Cauca Salvjina River inflow shows a different distibution of favourable wind months that falls in Jun-Jul-Aug. The river inflow is not correlated (factor : -0.02) with all Colombian river inflow as the three others (factor >0,83)
- August month is idenfified as a favorable wind month, but this is on a vage normalised wind speed 100,9% above the average and thus not a significant finding.

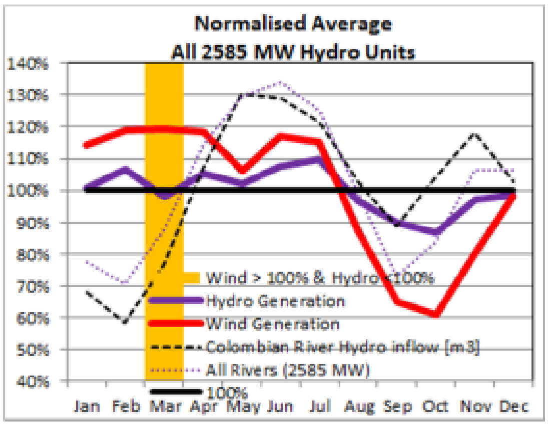
5.5.2 Based on Hydro Production, Aug95-Dec12

The actual reported hydro production for each of the selected hydro generation units and the total pool have been compared with the calculated wind production from the 200x2,0 MW wind farm in the years Aug 95-Dec 12.

Wind & Hydro production – monthly average Aug 95-Mar13

The tables and figures below show the normalised average wind and hydro production (based on yearly average for the full time window) and indicates the "favourable wind months". It is noted that the wind data set "wind speed" (from the previous section) vs. "wind energy production" used in the table below are in good correlation. This is verified by a calulated correlation coeficient above 0,95.

All Hydro Generation Units (2885 MW)													Correlation		
Normalised Monthly Average Hydro Production vs. 200 x 2 MW Wind Production												Aug95 - Mar 13	Hydro vs. Wind	Production vs. Inflow	
Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Production	All Rivers	Actual River
Hydro	100,8%	106,5%	98,1%	105,1%	102,0%	107,5%	109,9%	96,7%	89,8%	86,4%	97,1%	98,5%	0,88	0,15	0,53
Wind	114,3%	119,0%	119,1%	118,2%	106,0%	117,2%	115,1%	87,1%	65,0%	60,8%	80,2%	98,0%			
Hydro < 100% & Wind > 100%	No	No	Yes	No	No	No	No	No	No	No	No	No			



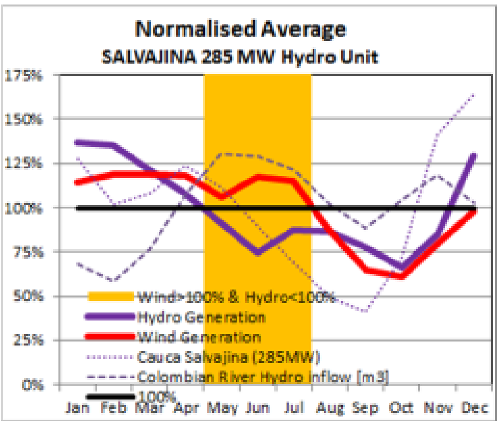
Findings: All units pooled

Favourable wind months: Marts month only (not even being significant with 98,1% normalised hydro production).

Correlation "hydro production vs. hydro in-flow":
Factor 0,15 for all rivers / No correlation
Factor 0,53 for actual river / Fair correlation

Correlation "hydro/wind production":
Factor 0,88 / Good correlation

SALVAJINA 285 MW Hydro Generation Unit													Correlation		
Normalised Monthly Average Hydro Production vs. 200 x 2 MW Wind Production												Aug95 - Mar 13	Hydro vs. Wind	Production vs. Inflow	
Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Production	All Rivers	Actual River
Hydro	136,9%	135,0%	121,4%	107,8%	90,7%	74,9%	87,6%	86,5%	77,9%	66,6%	85,3%	129,4%	0,60	-0,69	0,61
Wind	114,3%	119,0%	119,1%	118,2%	106,0%	117,2%	115,1%	87,1%	65,0%	60,8%	80,2%	98,0%			
Hydro < 100% & Wind > 100%	No	No	No	No	Yes	Yes	Yes	No	No	No	No	No			



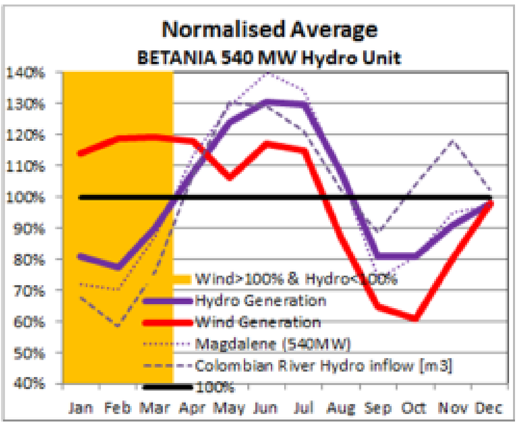
Findings: Salvajnia

Favourable wind months: May-Jun-Jul.

Correlation "hydro production vs. hydro in-flow":
Factor -0,69 for all rivers / Large inverse correlation
Factor 0,61 for actual river / Fair but not significant correlation
The tremendous impact on correlation factor when the actual river hydro inflow is used could be expected. This is a consequence of the non-existing correlation (-0,02) of the hydro inflow between the Cauca Salvajina and all Colombian rivers as previously discussed.

Correlation "hydro/wind production": Factor 0,19 / No correlation.

BETANIA 540 MW Hydro Generation Unit													Correlation		
Normalised Monthly Average Hydro Production vs. 200 x 2 MW Wind Production												Aug95 - Mar 13	Hydro vs. Wind	Production vs. Inflow	
Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Production	All Rivers	Actual River
Hydro	80,9%	77,6%	90,3%	107,8%	123,9%	130,8%	129,9%	108,2%	80,8%	81,0%	90,8%	98,0%	0,40	0,80	0,99
Wind	114,3%	119,0%	119,1%	118,2%	106,0%	117,2%	115,1%	87,1%	65,0%	60,8%	80,2%	98,0%			
Hydro < 100% & Wind > 100%	Yes	Yes	Yes	No	No	No	No	No	No	No	No	No			

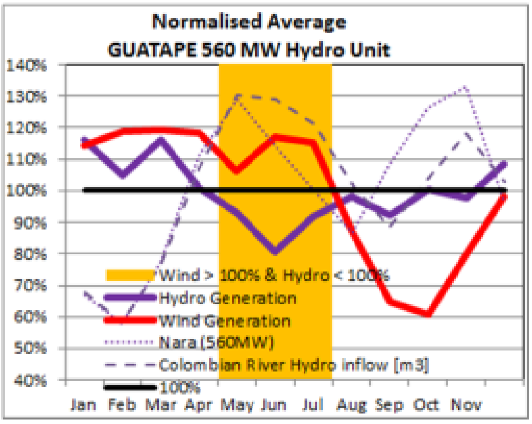


Findings: Betania
Favourable wind months: Jan-Feb-Mar.

Correlation "hydro production vs. hydro in-flow":
Factor 0,80 for all rivers / Good correlation
Factor 0,99 for actual river / almost complete correlation

Correlation "hydro/wind production":
Factor 0,4 / No correlation

GUATAPE 560 MW Hydro Generation Unit													Correlation		
Normalised Monthly Average Hydro Production vs. 200 x 2 MW Wind Production												Aug95 - Mar 13	Hydro vs. Wind	Production vs. Inflow	
Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Production	All Rivers	Actual River
Hydro	116,4%	104,8%	116,2%	100,6%	93,0%	80,8%	91,7%	98,0%	92,2%	100,3%	97,6%	108,5%	0,19	-0,74	-0,62
Wind	114,3%	119,0%	119,1%	118,2%	106,0%	117,2%	115,1%	87,1%	65,0%	60,8%	80,2%	98,0%			
Hydro < 100% & Wind > 100%	No	No	No	No	Yes	Yes	Yes	No	No	No	No	No			
	0,0	0,0	0,0	0,0	2,0	2,0	2,0	0,0	0,0	0,0	0,0	0,0			

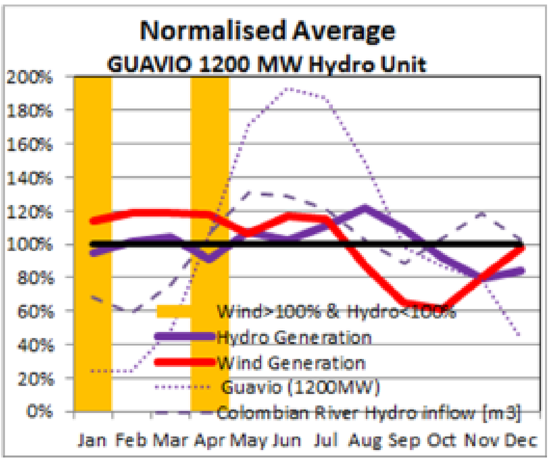


Findings: Guatape
Favourable wind months: Jan-Feb-Mar.

Correlation "hydro production vs. hydro in-flow":
Factor -0,74 for all rivers / Inverse correlation
Factor -0,69 for actual river / Inverse correlation

Correlation "hydro/wind production":
Factor 0,19 / No correlation

GUAVIO 1200 MW Hydro Generation Unit													Correlation		
Normalised Monthly Average Hydro Production vs. 200 x 2 MW Wind Production												Aug95 - Mar 13	Hydro vs. Wind	Production vs. inflow	
Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Production	All Rivers	Actual River
Hydro	95,0%	101,9%	104,7%	91,1%	107,2%	102,6%	111,4%	121,8%	109,2%	92,1%	78,9%	84,1%	0,11	-0,02	0,50
Wind	114,3%	119,0%	119,1%	118,2%	106,0%	117,2%	115,1%	87,1%	65,0%	60,8%	80,2%	98,0%			
Hydro < 100% & Wind > 100%	Yes	No	No	Yes	No	No	No	No	No	No	No	No			



Findings: Guavio
Favourable wind months: Jan & Apr.

Correlation "hydro production vs. hydro in-flow":
Factor -0,02 for all rivers / Absolute no correlation
Factor 0,50 for actual river / No correlation
(The large normalised in-flow in May→ Aug above 140% does not impact the normalised hydro production falling below 120% in the same months. This could be explained by the prevailing operation of the water reservoirs.

Correlation "hydro/wind production": Factor 0,11 / No correlation

Summary

The analyse related to wind speed vs. hydro inflow concluded that the months Jan, Feb and Mar can be considered as favourable wind months. This conclusion is not supported by the actual production data from the 200MW wind farm and the production data from the selected hydro power plants.

The occurrence of favourable wind months identified from the actual energy production from the four selected hydro power plants is summarised in the following table.

Favorable wind months based on actual production of selected Hydro Power Plants												
Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Cauca Salvajina (285MW)	No	No	No	No	Yes	Yes	Yes	No	No	No	No	No
Magdalene (540MW)	Yes	Yes	Yes	No	No	No	No	No	No	No	No	No
Nara (560MW)	No	No	No	No	Yes	Yes	Yes	No	No	No	No	No
Guavio (1200MW)	Yes	No	No	Yes	No	No	No	No	No	No	No	No
All Rivers (2585 MW)	No	No	Yes	No	No	No	No	No	No	No	No	No

It is shown that

- ➢ Aug-Dec do not have favourable wind months
- ➢ Jan, Mar, May, Jun & Jul have the most frequent number of FWM
- ➢ Feb & Apr have least number of FWM

- No interrelation between the favourable wind months and the "CREG dry months" defined as Dec-Apr can be identified.

Wind & Hydro production – occurrence based on monthly average each year

The distribution of favourable wind months occurring in the Aug 95 – Mar 13 time span for the four selected hydro generating units has been analysed for each year and month. The table below summers the analysis. (The FWM distribution detailed for each month and year for the each of the selected hydro generating units are shown in Appendix F.

Distribution of favorable wind months

	CHBG: 540MW		GTPE: 560MW		GVIO: 1200MW		SLVJ: 285MW		All units: 2585MW	
Jan	11	61%	5	28%	6	33%	5	28%	6	33%
Feb	9	53%	3	18%	4	24%	3	18%	4	24%
Mar	8	47%	4	24%	5	29%	7	41%	5	29%
Apr	7	44%	7	44%	5	31%	5	31%	5	31%
May	2	13%	6	38%	3	19%	5	31%	3	19%
Jun	1	6%	9	53%	7	41%	11	65%	7	41%
Jul	0	0%	9	53%	7	41%	11	65%	7	41%
Aug	1	6%	6	33%	1	6%	7	39%	1	6%
Sep	2	11%	1	6%	1	6%	2	11%	1	6%
Oct	1	6%	0	0%	1	6%	1	6%	1	6%
Nov	1	6%	1	6%	1	6%	1	6%	1	6%
Dec	5	28%	4	22%	6	33%	6	33%	6	33%

> 40 % Proberbility between Aug 95 - Mar 13
30 -40 % Proberbility between Aug 95 - Mar 13
20 -30 % Proberbility between Aug 95 - Mar 13
< 20 % Proberbility between Aug 95 - Mar 13

It is observed that

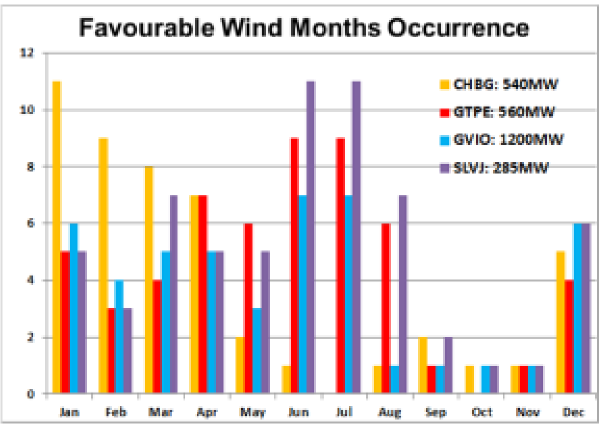
- the occurrence of FWM for CHBG 540MW align very good with the CREG dry months. (The correlation between the hydro inflow and production is good for the 540MW unit).

- June & July months have large FWM occurrence for three units (285MW, 560MW, and 1200MW) where the correlation between hydro inflow and the actual production is poor or inverse.

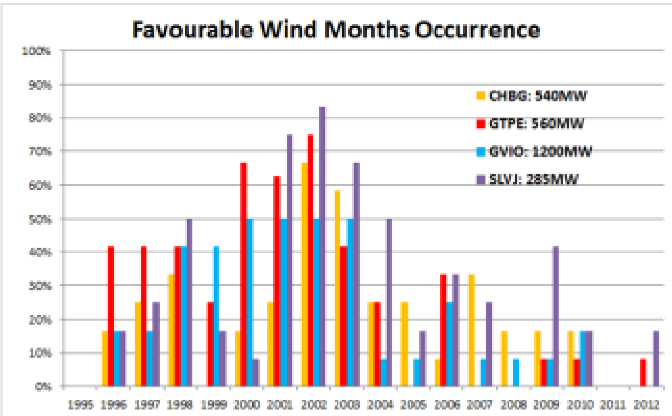
From the tables in Appendix F the following is observed:

- No clear interrelation between the El-Niño months and the "favourable wind months" exists when the actual production from the 200 MW wind farm and the selected hydro power plants are analysed.

- "Favourable wind months" only very rarely occur in Sep, Oct & Nov.



- "Favourable wind months" do not occur in all years. The percentage of yearly occurrence over the years is illustrated below.



- Approximately 25% of all months in 1995-2012 are identified as "favourable wind months" for each hydro generation unit.

5.5.3 El Niño years / months

The complementarity study also considers the El-Niño months and the dry months defined by CREG.

The El-Niño months are identified for the years 1950-2013 by US National Weather Service Climate Prediction Centre at the web site:

http://www.cpc.ncep.noaa.gov/products/analysis_monitoring/ensostuff/ensoyears.shtml

The occurrence of the El-Niño months (warm) from 1950 is defined and tabled on this web-site with the following description*: Warm (red) and cold (blue) episodes based on a threshold of +/- 0.5oC for the Oceanic Niño Index (ONI) [3 month running mean of ERSST.v3b SST anomalies in the Niño 3.4 region (5oN-5oS, 120o-170oW)], based on centred 30-year base periods updated every 5 years. For historical purposes cold and warm episodes (blue and red coloured numbers) are defined when the threshold is met for a minimum of 5 consecutive over-lapping seasons.*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1983	2,2	1,9	1,5	1,2	0,9	0,6	0,2	-0,2	-0,5	-0,8	-0,9	-0,8
1984	-0,5	-0,3	-0,3	-0,4	-0,5	-0,5	-0,3	-0,2	-0,3	-0,6	-0,9	-1,1
1985	-1	-0,9	-0,7	-0,7	-0,7	-0,6	-0,5	-0,5	-0,5	-0,4	-0,4	-0,4
1986	-0,5	-0,4	-0,2	-0,2	-0,1	0	0,3	0,5	0,7	0,9	1,1	1,2
1987	1,2	1,3	1,2	1,1	1	1,2	1,4	1,6	1,6	1,5	1,3	1,1
1988	0,8	0,5	0,1	-0,2	-0,8	-1,2	-1,3	-1,2	-1,3	-1,6	-1,9	-1,9
1989	-1,7	-1,5	-1,1	-0,8	-0,6	-0,4	-0,3	-0,3	-0,3	-0,3	-0,2	-0,1
1990	0,1	0,2	0,3	0,3	0,2	0,2	0,3	0,3	0,4	0,3	0,4	0,4
1991	0,3	0,2	0,2	0,3	0,5	0,7	0,8	0,7	0,7	0,8	1,2	1,4
1992	1,6	1,5	1,4	1,2	1	0,7	0,3	0	-0,2	-0,3	-0,2	0
1993	0,2	0,3	0,5	0,6	0,6	0,5	0,3	0,2	0,2	0,2	0,1	0,1
1994	0,1	0,1	0,2	0,3	0,4	0,4	0,4	0,4	0,5	0,7	1	1,2
1995	1	0,8	0,6	0,3	0,2	0	-0,2	-0,4	-0,7	-0,8	-0,9	-0,9
1996	-0,9	-0,8	-0,6	-0,4	-0,3	-0,2	-0,2	-0,3	-0,3	-0,3	-0,4	-0,5
1997	-0,5	-0,4	-0,1	0,2	0,7	1,2	1,5	1,8	2,1	2,3	2,4	2,3
1998	2,2	1,8	1,4	0,9	0,4	-0,2	-0,7	-1	-1,2	-1,3	-1,4	-1,5
1999	-1,5	-1,3	-1	-0,9	-0,9	-1	-1	-1,1	-1,1	-1,3	-1,5	-1,7
2000	-1,7	-1,5	-1,2	-0,9	-0,8	-0,7	-0,6	-0,5	-0,6	-0,6	-0,8	-0,8
2001	-0,7	-0,6	-0,5	-0,4	-0,2	-0,1	0	0	-0,1	-0,2	-0,3	-0,3
2002	-0,2	0	0,1	0,3	0,5	0,7	0,8	0,8	0,9	1,2	1,3	1,3
2003	1,1	0,8	0,4	0	-0,2	-0,1	0,2	0,4	0,4	0,4	0,4	0,3
2004	0,3	0,2	0,1	0,1	0,2	0,3	0,5	0,7	0,8	0,7	0,7	0,7
2005	0,6	0,4	0,3	0,3	0,3	0,3	0,2	0,1	0	-0,2	-0,5	-0,8
2006	-0,9	-0,7	-0,5	-0,3	0	0,1	0,2	0,3	0,5	0,8	1	1
2007	0,7	0,3	-0,1	-0,2	-0,3	-0,3	-0,4	-0,6	-0,8	-1,1	-1,2	-1,4
2008	-1,5	-1,5	-1,2	-0,9	-0,7	-0,5	-0,3	-0,2	-0,1	-0,2	-0,5	-0,7
2009	-0,8	-0,7	-0,5	-0,2	0,2	0,4	0,5	0,6	0,8	1,1	1,4	1,6
2010	1,6	1,3	1	0,6	0,1	-0,4	-0,9	-1,2	-1,4	-1,5	-1,5	-1,5
2011	-1,4	-1,2	-0,9	-0,6	-0,3	-0,2	-0,2	-0,4	-0,6	-0,8	-1	-1
2012	-0,9	-0,6	-0,5	-0,3	-0,2	0	0,1	0,4	0,5	0,6	0,2	-0,3
2013	-0,6	-0,6	-0,4									
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec

This study includes wind data series from 1983, thus the occurrence of El Niño months in the same time span is analysed. The table beside illustrates the number and occurrence of the El-Niño months for all months identified.

It is observed that no general trend in the occurrence of the El-Niño months over the years or the monthly distribution can be concluded.

(It is noticed that this study also considers the months in 1993 and 2012 as El-Niño months even if the criteria related to that five consecutive months > +0,5oC not is fulfilled).

Summarising:
1950- 2013: El-Niño months are 212 (27,8% of total)
1983- 2013: El-Niño months are 96 (26,2% of total)
1983-2013: CREC dry months "Dec…Apr are 160 (42% of total)

It is noticed that the total number of CREG dry months (152) and the actual El-Niño months (96) within the 1983-2013 time spans not are comparable, since they differ with approximately 55 months (60%).

The monthly distribution over the year also is very different and will have a significant impact on the ENFICC calculations when the dry months and El-Niño months impact shall be considered and be investigated.

Based on above it is observed that the interrelation between the CREG defined dry months and the El-Niño months reported not can be explained in the temperatures measured.

This study is not aiming at investigating the weather statistics and will conclude on the El-Niño phenomena defined with ΔTemp > 0,5 ºC in five consecutive months. (1993 and 2012 with 2 and 4 consecutive months are also considered as El-Niño in this study).

The ENFICC calculations however will be made for all months, El-Niño months and the CREG defined dry months. Reference is made to *Section 6 Analyses of firm energy factor.*

5.5.4 Hydro vs Wind – El Niño/CREG dry months

Analysing the hydro vs. wind energy production in relation to the occurrence of the El-Niño and CREG dry months takes basis in the assumptions and preconditions listed below:

- Time span for complementarity analysis
  A time span Aug 95 → Mar 13 with a full data set for the hydro power plans and unchanged installed capacity is used

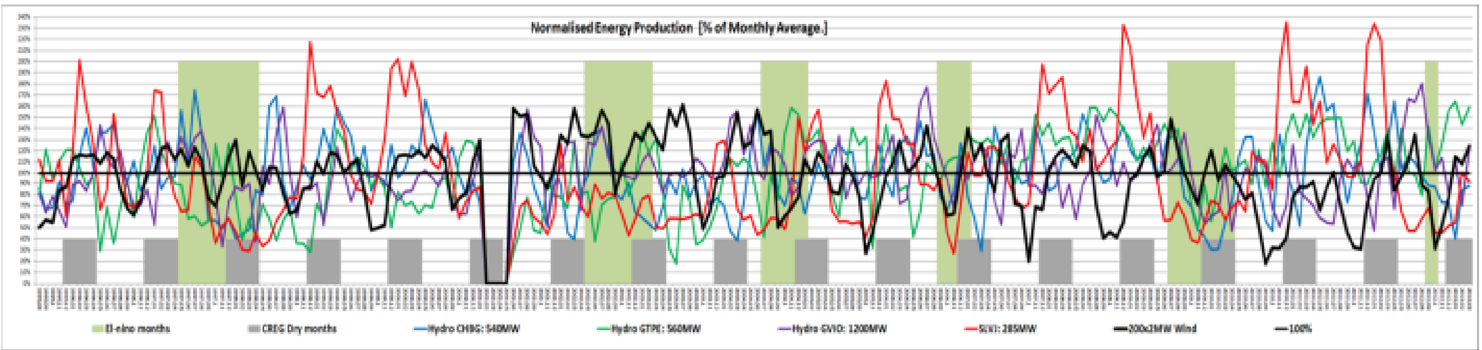
- Hydro generation production
  Actual hydro generation from the selected generation units (285MW, 540 MW, 560 MW and 1200MW) reported in the "Genera Real Hidrau Hora por central.txt" data file made available for the hydro production is used.

- Wind energy production
  The wind energy is calculated for the 200x2,0MW as basis for comparison with the hydro production

- El-Niño months are defined with ΔTemp > +0,5

- CREG dry months are defined as Dec….Mar for all years

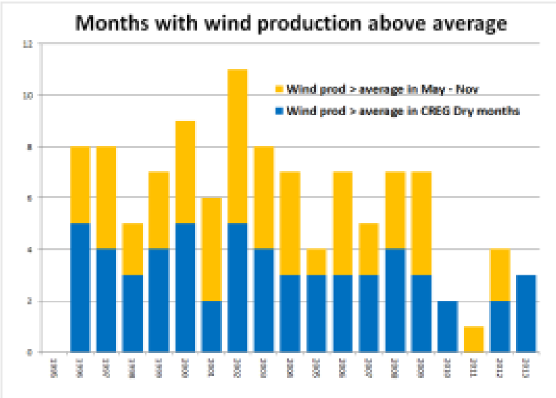
The normalised energy production "% actual month/average month" for the 200x2,0MW wind farm compared with the hydro generating units is shown below.



The El-Niño months are indicated in light green and the CREG months are indicated in grey. It is observed

- that the no clear interrelation can be seen between the wind energy production and the El-Niño months

- that the wind production as a tomb rule seems to be above monthly average in the dry months defined by CREG. This is illustrated in the figure below



- that no clear interrelation can be seen between the hydro production and the El-Niño months or the CREG dry months.

The occurrence of "favourable wind months" in relation to the actual El-Niño and the CREG dry months have been analysed and is shown below.

	"Favourable Wind Months"				
Hydro generation pool	*CHBG 540MW*	*GTPE 560MW*	*GVIO: 1200MW*	*SLVJ: 285MW*	*All units 2585MW*
Full time span: Aug95 - Mar13	212				
Wind>100% & Hydro < 100%	49 *23,1%*	55 *25,9%*	50 *23,6%*	65 *30,7%*	48 *22,6%*
El-Nino Months	46				
Wind>100% & Hydro < 100%	9 *18,5%*	9 *18,5%*	6 *13,0%*	13 *27,2%*	7 *14,1%*
CREG dry months	86				
Wind>100% & Hydro < 100%	21 *23,8%*	12 *13,4%*	16 *18,6%*	14 *15,7%*	14 *15,7%*

It is observed that

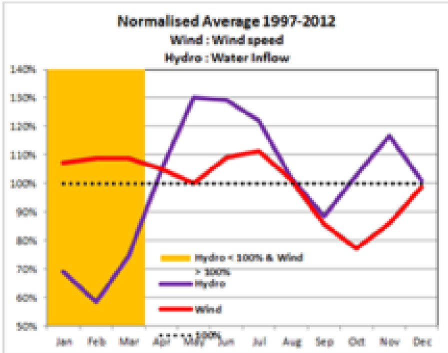
- The relative occurrence of "favourable wind months" during the El-Niño and CREG time span decreases compared to the full time span. (Except for the 540 MW unit).

- The actual number of "favourable wind months" for the 540MW unit during the CREG dry months is significantly higher than for the other units. (The hydro inflow and the energy production are correlated for the 540 MW unit. This is not the case for the three other hydro units).

- The 285MW unit has the largest occurrence of “favourable wind months”. This could partly explain in the fact that this unit also have the largest standard deviation (48%) for the monthly energy production.

5.6 Conclusions

- Wind Speed vs. Hydro Inflow – *All Months (1997-2012)*
  Three months (Jan/Feb/Mar) have normalised Wind Speed above its yearly average and normalised Hydro Inflow below the yearly average.



- Wind vs. Hydro Production – *All Months (1995-2012)*
  The monthly production reported from the selected hydro units seems to be significantly influenced by the dams and reservoirs.

  It is verified that only a insignificant number of favourable wind months occur during Aug-Nov.

  The occurrence of favourable wind months for the hydro production unit seems to be dependent on whether the hydro flow and the production distribution is correlated or not.

  Only four months (Jan/Feb/Mar/Apr) have a high frequency of favourable wind months when the hydro flow and the production distribution is correlated.

  Only two months (Jun/Jul) have a high frequency (>40%) of favourable wind months when the hydro flow and the production distribution not are correlated. (285MW, 560MW and 120MW units). It is observed that Apr, May and Aug have a moderate occurrence (30%-40%) of favourable wind months.

- El-Niño and CREG dry months
  The study cannot verify a correlation between the El-Niño phenomena and the months being defined as dry months by CREG.

  Wind production as a tomb rule seems to be above monthly average in the dry months defined by CREG.

  No clear interrelation between the wind energy production and the El-Niño months has been identified.

  No clear interrelation between the occurrence of favourable wind months and the El-Niño months has been identified.

6 Analyses of firm energy factor, ENFICC

6.1 Introduction

This study does not aim at reviewing the CREG ENFICC calculation method or suggesting a different calculation approach. This has already been addressed and discussed intensively in previous study reports (Reference 4 & 5).

Firm energy is defined as the maximum monthly energy that can be produced without deficits during the analysis period.

This study will be based on the method currently adopted by CREG when a wind data series is available and aims at investigating the influence on the $ENFICC_{95\%}$ when:

- The wind turbine size is increased (1,3 MW → 2,5….3,0MW)
- A portfolio of wind & hydro generation capacity is considered as one production unit
- $ENFICC_{95\%}$ is calculated for time spans that includes all months.
- $ENFICC_{95\%}$ is calculated for time spans that only include the El-Niño and the CREG dry months.
- $ENFICC_{95\%}$ is calculated for time spans that do not include El-Niño and the CREG dry months.

The outcome of ENFICC calculations implemented in this report will justify a recommended adjustment of the ENFICC for the wind farms.

6.2 Wind farms

The current methodology used by CREG is defined in reference 6 *Ministerio de Minas y Energia, Resolucion No. 148, 21 Oct 2011.*

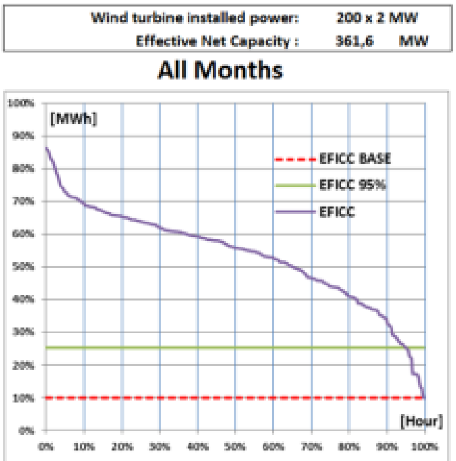
The prevailing $ENFICC_{95\%}$: 7,6% for wind farms based on the CREG's method (when considering the Jepirachi wind farm) is considerably low compared with the $ENFICC_{95\%}$: 30% for the hydro plans without reservoirs.

The $ENFICC_{base}$ and $ENFICC_{95\%}$ are calculated in line with the current adopted method for the following wind farm and scenarios based on the production from each hour but summarised on a monthly basis.

	Aug 95 – Mar 13				
Months	All months	El-Niño months	All months Ex. El-Niño	CREG Dry months	All months Ex. CREG
200x2,0MW Wind farm	✚	✚	✚	✚	✚
134x3,0MW Wind farm	✚	✚	✚	✚	✚
15x1,3MW Wind farm (Jepirachi)	✚	✚	✚	✚	✚

The $ENFICC_{95\%}$ calculation for each of above listed scenarios are presented in probability distribution curves "from the lowest to the highest level of firm energy, based on the monthly energy production". Reference is given to Appendix H, I & J.

A probability distribution curve is shown beside, for the 200x2,0MW wind farm based on all months during the time span 1983-2013.



	EFICC BASE	EFICC 95%	EFFIC >95%	EFFIC <95%	NCF
	9,9%	25,2%	25,2%	25,5%	53,5%
Months	363	18	95,04%	94,8%	
		5,0%			

It is noticed that:

- CEN for the wind farm is calculated as the energy supplied via the 230 kV transmission line at the grid substation in Cuestecita.

- $ENFICC_{base}$ (9,9%) is calculated from 363 months energy production.

- $ENFICC_{95\%}$(25,2%) is calculated from 18 months energy production (5% of all months considered).

- 18 out of the 363 months (5,0%) have an energy production falling between $ENFICC_{base}$ and $ENFICC_{95\%}$.

  The number of month data (365) does not allow an exact calculation of the $ENFICC_{95\%}$ figure. Consequently, an interpolation is based on the two closest ENFICC figures above/below 95% is implemented. The numbers used for this interpolation are shown as:

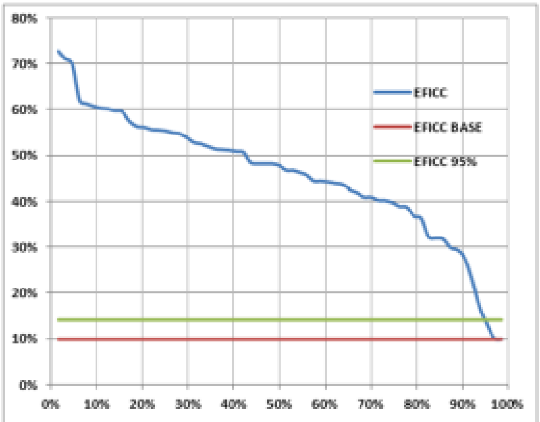
ENFICC > 95%: 25,2% & 95,04%
ENFICC <95%: 25,5% & 94,8%.

This approach does not have a significant impact in the 1983-2013 analysis when all 363 months are analysed. However it is mandatory when only the Nov 00 – Mar 13 time span in relation to EL-Niño periods (34 months) and CREG dry months (64 months) are analysed. The figure below illustrates that only 3 of the 34 months fall between $\text{ENFICC}_{\text{base}}$ and $\text{ENFICC}_{95\%}$.

The numbers used for the interpolation are
ENFICC > 95%: 13,2% & 95,4%
ENFICC <95%: 16,9% & 93,8%.

Wind turbine installed power:	15 x 1.3 MW
Effective Net Capacity :	17,4 MW

CREG Dry Months



	EFICC BASE	EFICC 95%	EFFIC >95%	EFFIC <95%	NCF
	9,9%	14,1%	13,2%	16,9%	45,8%
Months	64	3	95,4%	93,8%	
		4,7%			

It is noted that the interpolation is significant (≈1-1,5%) and based on data sets with a poor monthly resolution.

Thus, only a trend can be identified since the ENFICC not can be justified with appropriate accuracy by this calculation approach based on the monthly energy production. (A calculation approach based on a weekly basis instead of monthly basis will improve the reliability of the ENFICC calculation. This however will not be consistent with the current monthly resolution approach for dry/wet adopted by CREG and it will be very different to implement in a market regulatory context).

The table below summarises the ENFICC calculations implemented for the various scenarios for the Aug 95 – Mar 13 timespan. (Reference is given to Appendix H, I,J)

Time span	15x1.3 MW Wind Farm			200x2 MW Wind Farm			134 x 3,0MW Wind Farm		
Aug 1995 - Mar 2013	ENFICC_base	ENFICC_95%	NCF	ENFICC_base	ENFICC_95%	NCF	ENFICC_base	ENFICC_95%	NCF
All months	7,5%	17,5%	43,0%	9,9%	22,5%	52,7%	10,6%	24,1%	55,0%
El-Nino Months	12,9%	22,7%	45,3%	16,3%	28,8%	55,2%	17,4%	30,5%	57,5%
All months ekskl. El-Nino Months	7,5%	16,9%	42,2%	9,9%	21,8%	51,8%	10,6%	23,4%	54,1%
CREG Dry Months	16,9%	29,5%	47,7%	21,8%	37,8%	58,5%	23,4%	40,1%	61,0%
All months ekskl. CREG Dry Months	7,5%	13,2%	39,5%	9,9%	17,1%	48,4%	10,6%	18,4%	50,5%

The most important findings are summarised below:

- WTG unit size
  Increasing the WTG unit size will also increase the ENFICC and the Net Capacity Factor.

  - ENFICC

    $ENFICC_{Base}$
    Small units 19.5 MW Jepirachi (7,5%...16,9%) →
    Large units 402 MW "132x3MW" (10,6%...23,4%)

    $ENFICC_{95\%}$
    Small units 19.5 MW Jepirachi (13,2 % …. 29,5%) →
    Large units 402 MW "132x3MW" (18,4% …. 40,1%)

    First figure represent minimum of all months the second is maximum of the El Niño or CREG dry month time span only.

  - Average Net Capacity Factor
    Small units 19.5 MW Jepirachi (39,5% …. 47,7%) →
    Large units 402 MW "132x3MW" (50,5% …. 61,0%)

  Above is a result of the higher hub height of the wind turbine giving an increase in the average wind speed and the larger diameter of the wings that allow the units producing more energy at low wind speed.

- Wind farm performance All months vs. El-Niño months

  - ENFICC
    A significant increase of the $ENFICC_{Base}$ (≈ +6%) and $ENFICC_{95\%}$ (≈ +6%) is observed for both the 400 MW and the 402MW wind farm when comparing the El-Niño months separate with all the months in the time range Aug 95 – Mar 13.

  - Net Capacity Factor
    The wind farm performance is improved in the El-Niño months compared with the scenario when all months are considered.

The NCF increases in the range 2,0% .. 3,8%.

- Wind farm performance All months vs. CREG dry months
  $ENFICC_{CREG\ dry\ months}$ are significant higher than $ENFICC_{all\ months}$ and also higher than $ENFICC_{El\text{-}Niño\ months}$

  - ENFICC
    A significant increase of the $ENFICC_{Base}$ (≈ +11%) and $ENFICC_{95\%}$ (≈ +15%) is observed for both the 400 MW and the 402MW wind farm when comparing the CREG dry months separate with all the months in the time range Aug 95 – Mar 13.

  - Net Capacity Factor
    The wind farm performance is improved in the CREG dry months compared with the scenario when all months are considered.

    The NCF increases in the range 5,0% .. 6%.

6.3 Hydro power plants

The current methodology used by CREG for the hydro generating plans has been informed by UMPE who forwarded a calculation sheet requiring a comprehensive data input with many parameters not available for the Consultant. ENFICC calculations for the hydro power plants based on CREG's methodology taking the dams and reservoirs into account fall outside of this studies scope. This study aims at investigating the ENFICC for Wind/Hydro generation units in a portfolio context. Thus a similar calculation approach for the wind and hydro generating plans is selected for this study.

The $ENFICC_{base}$ and $ENFICC_{95\%}$ for each of the selected hydro generation units are calculated from the actual energy production being reported on an hourly basis in the *Genera Real Hidrau Hora por central.txt* provided by UMPE.

The calculation method used for elaboration of the probability distribution curves is similar with the one used for the wind farms. The effective net capacity (CEN as defined in CREGs method) however is assumed to be equal to the total installed capacity.

The elaboration of the probability distribution curves is based on the actual production each hour but summarised on a monthly basis for the timespan Aug 95 – Mar 13. (The installed capacity remains unchanged during the full time span).

The tables below summarises the ENFICC calculations for the various scenarios for each hydro generating unit:

Hydro Generating Units: Firm Energy Factor & Average Net Capacity Factor

	SLVJ: 285MW			CHBG: 540MW			GTPE: 560MW			GVIO: 1200MW			All units: 2585MW		
	ENFICC base	ENFICC 95%	NCF	ENFICC base	ENFICC 95%	NCF	ENFICC base	ENFICC 95%	NCF	ENFICC base	ENFICC 95%	NCF	ENFICC base	ENFICC 95%	NCF
All months	11,8%	18,3%	43,1%	12,6%	20,6%	43,7%	10,8%	22,0%	59,0%	17,1%	27,3%	50,6%	24,5%	34,1%	50,1%
El-Nino Months	11,8%	13,0%	27,7%	13,0%	15,7%	35,7%	22,6%	24,5%	54,5%	17,1%	21,1%	49,4%	24,5%	27,2%	45,6%
All months ekskl. El-Nino Months	14,2%	19,9%	47,3%	12,6%	21,9%	45,7%	10,8%	20,8%	60,0%	23,3%	28,3%	50,7%	29,6%	37,9%	51,3%
CREG Dry Months	12,3%	20,3%	54,3%	12,6%	16,8%	39,6%	16,3%	30,4%	64,5%	19,5%	25,6%	48,2%	24,5%	33,1%	50,8%
All months ekskl. CREG Dry Months	11,8%	17,0%	34,9%	20,2%	25,2%	46,3%	10,8%	20,7%	54,9%	17,1%	28,3%	52,0%	27,4%	36,5%	49,5%

It is noticed that the ENFICC calculated from the actual energy production for each hydro plant are in the range of ($ENFICC_{base}$ 11%-17%) and ($ENFICC_{95\%}$ 18%-27%). This is significantly less than expected since 30% and 50% currently are considered for production units with or without storage. This can partly be explained in the fact that the CEN "effective net capacity" are informed to be equal to the installed capacity. This will impose that the ENFICC figures are lower.

It is also observed that the differences of the ENFICC (resulting from a comparison of the all month timespan with the El-Nino & the CREG dry months timespan) not are comparable in size or trend (both positive and negative changes occur).

The $ENFICC_{95\%}$ change for the various time spans compared with the all month timespan are indicated below for each of the generating units.

Changes ENFICC 95%	285MW	540MW	560MW	1200MW	2825MW
All months	0,0%	0,0%	0,0%	0,0%	0,0%
El-Nino Months	-5,3%	-4,9%	2,6%	-6,2%	-6,8%
All months ekskl. El-Nino Months	1,6%	1,3%	-1,2%	1,0%	3,8%
CREG Dry Months	2,0%	-3,7%	8,4%	-1,7%	-0,9%
All months ekskl. CREG Dry Months	-1,3%	4,7%	-1,2%	1,0%	2,4%

- "All months vs. El- Niño"
  $ENFIC_{95\%}$ decreases ≈ 5-6% in general
  (The 560 MW unit in particular shows a different behaviour and is not considered).

- "All months vs. CREG dry"
  $ENFICC_{95\%}$ shows no clear behaviour. (Changes varies between -1,3% and +4,7%)

Changes Average Net Capacity Factor	285MW	540MW	560MW	1200MW	2825MW
All months	0,0%	0,0%	0,0%	0,0%	0,0%
El-Nino Months	-15,4%	-8,0%	-4,5%	-1,1%	-4,6%
All months ekskl. El-Nino Months	4,2%	2,0%	1,0%	0,2%	1,2%
CREG Dry Months	11,2%	-4,1%	5,5%	-2,4%	0,6%
All months ekskl. CREG Dry Months	-8,2%	2,6%	-4,1%	1,4%	-0,6%

- "All months vs. El- Niño"
  NCF decreases between 1-15% thus not give a clear behaviour except that all are increasing.

- All months vs. CREG dry"
  NCF shows no clear behaviour. (Changes varies between -8.2% and 2.8%)

This study does not aim at calculating the ENFICC for hydro power plans only.

The study aims at investigating the ENFICC impact from a hydro/wind portfolio compared with the separate hydro and wind generating units. Only the trend is investigated and no accurate recommendations in relation to the portfolio ENFICC are targeted. Consequently the above ENFICC figures will be used for the portfolio analyse only.

6.4 Portfolio – ENFICC analysis

The portfolio ENFICC study is based on a 50% wind and 50 % hydro generation mix.

The production data previously computed for the hydro generation units are used for the wind/hydro portfolio analyse in relation to the ENFICC.

The monthly energy production for the 285MW, 540MW, 560MW, 1200MW wind farm scenarios used for the portfolio ENFICC analysis are scaled in percentage from the 400MW wind farm (200x2MW) in relation to the effective net capacity "CEN".

Eg.:
400MW park (installed capacity 400MW / CEN= 361,5 MW)
Monthly wind energy production, Nov. 2000: 116,4GWh

540MW production unit (Installed capacity 598 MW / CEN=540MW)
Monthly wind energy production, Nov. 2000: 116,4x540/361,5GWh = 173,8GWh

The $ENFICC_{base}$ and $ENFICC_{95\%}$ for the wind/hydro generation portfolios are calculated from a monthly energy production by adding the monthly energy production from the two wind farms and the hydro generator plant.

The table below summarises the ENFICC calculations implemented for the various portfolio scenarios:

	Time spans: Aug 95– Mar 13				
Months	All	El-Niño	All excl. El-Niño	CREG dry	All excl. CREG dry
2x285 MW Wind/Hydro Plant Pool	+	+	+	+	+
2x540 MW Wind/Hydro Plant Pool	+	+	+	+	+
2x560 MW Wind/Hydro Plant Pool	+	+	+	+	+
2x1200 MW Wind/Hydro Plant Pool	+	+	+	+	+
2x2585MW Wind/Hydro Plant Pool	+	+	+	+	+

The ENFICC and NCF calculated for each of above listed scenarios within the time spans defined are presented in table below:

Portfolio Hydro & Wind Generating Units: Firm Energy Factor & Average Net Capacity Factor

	2x285 MW			2x 540 MW			2x285 MW			2x1200 MW			2x2585 MW		
	ENFICC base	ENFICC 95%	NCF	ENFICC base	ENFICC 95%	NCF	ENFICC base	ENFICC 95%	NCF	ENFICC base	ENFICC 95%	NCF	ENFICC base	ENFICC 95%	NCF
All months	16,1%	26,3%	47,9%	17,5%	30,2%	48,2%	22,3%	35,0%	55,9%	21,8%	33,2%	51,6%	28,3%	34,4%	51,4%
El-Nino Months	17,7%	23,9%	41,7%	26,7%	30,1%	45,7%	34,3%	36,8%	55,1%	33,1%	34,0%	52,4%	31,4%	35,2%	50,5%
All months ekskl. El-Nino Months	16,1%	28,9%	49,5%	17,5%	30,4%	48,8%	22,3%	33,6%	55,9%	21,8%	32,2%	51,3%	28,3%	33,5%	51,6%
CREG Dry Months	31,3%	37,8%	56,6%	32,7%	36,2%	49,2%	31,0%	42,4%	61,6%	28,2%	37,7%	53,4%	37,5%	41,6%	54,7%
All months ekskl. CREG Dry Months	16,1%	25,2%	41,6%	17,5%	28,5%	47,3%	22,3%	33,5%	51,6%	21,8%	32,1%	50,2%	28,3%	31,9%	49,0%

The differences of ENFICC$_{95\%}$ and NCF for each generation unit are tabled below:

Changes ENFICC 95%	285MW	540MW	560MW	1200MW	2825MW
All months	0,0%	0,0%	0,0%	0,0%	0,0%
El-Nino Months	-2,4%	-0,1%	1,8%	0,8%	0,8%
All months ekskl. El-Nino Months	2,6%	0,2%	-1,4%	-1,0%	-1,0%
CREG Dry Months	11,5%	6,0%	7,4%	4,5%	7,1%
All months ekskl. CREG Dry Months	-1,1%	-1,7%	-1,5%	-1,1%	-2,5%

Changes Average Net Capacity Factor	285MW	540MW	560MW	1200MW	2825MW
All months	0,0%	0,0%	0,0%	0,0%	0,0%
El-Nino Months	-6,2%	-2,5%	-0,8%	0,7%	-0,9%
All months ekskl. El-Nino Months	1,6%	0,6%	0,1%	-0,4%	0,1%
CREG Dry Months	8,7%	1,0%	5,8%	1,7%	3,3%
All months ekskl. CREG Dry Months	-6,3%	-0,9%	-4,2%	-1,4%	-2,5%

The observations in relation to the impact from the different time spans are:

- ENFICC$_{95\%}$
  - Time span El-Niño months only vs. All months
    No clear trend or significant change of ENFICC$_{95\%}$ (-2,4% … 1,8%) is observed when comparing with "All months".
  - Time span CREG dry months only vs. All months
    A significant increase of ENFICC$_{95\%}$ (4% .. 11%) is observed when comparing with "All months".
- Average Net Capacity Factor
  - Time span El-Niño months only vs. All months
    A negative trend but not aligned change of NCF (-6,4% … 0,7%) is observed when comparing with "All months".
  - Time span CREG dry months only vs. All months
    A positive trend of NCF (1,7% .. 8,7%) is observed when comparing with "All months".

6.5 Portfolio Impact Analysis

The ENFICC$_{base}$ and ENFICC$_{95\%}$ calculated for the various scenarios

- Wind Power Plants Separated
- Hydro Power Plants Separated
- Wind/Hydro Plants collected in portfolio

and the average Net Capacity Factor expressed as
NCF = Average [$E_{actual\_}$ / E_{max} calculated for each month].
E_{actual} : Actual energy production in the month
E_{max} : $P_{net\ power\ for\ wind\ farm}$ [MW] x Hour [h] in actual month

are tabled below:

Portfolio - SLVJ: 285MW & Wind Production with same CEN

	ENFICC_base / NCF						ENFICC_95%			Diff. ENFICC_95%	Diff. ENFICC_95%
	Wind		Hydro		W & H		Wind	Hydro	W & H	Wind vs. W&H	Hydro vs. W&H
All months	9,9%	43,0%	11,8%	43,1%	16,1%	47,9%	22,5%	18,3%	26,3%	3,8%	8,0%
El-Nino Months	16,3%	45,3%	11,8%	27,7%	17,7%	41,7%	28,8%	13,0%	23,9%	-5,0%	10,9%
All months ekskl. El-Nino Months	9,9%	42,2%	14,2%	47,3%	16,1%	49,5%	21,8%	19,9%	28,9%	7,1%	9,0%
CREG Dry Months	21,8%	47,7%	12,3%	54,3%	31,3%	56,6%	37,8%	20,3%	37,8%	0,0%	17,5%
All months ekskl. CREG Dry Months	9,9%	39,5%	11,8%	34,9%	16,1%	41,6%	17,1%	17,0%	25,2%	8,1%	8,2%

Portfolio - CHBG: 540MW & Wind Production with same CEN

	ENFICC_base / NCF						ENFICC_95%			Diff. ENFICC_95%	Diff. ENFICC_95%
	Wind		Hydro		W & H		Wind	Hydro	W & H	Wind vs. W&H	Wind vs. W&H
All months	9,9%	43,0%	12,6%	43,7%	17,5%	48,2%	22,5%	20,0%	30,2%	7,7%	9,0%
El Nino Months	16,3%	45,3%	13,0%	35,7%	26,7%	45,7%	28,8%	15,7%	30,1%	1,3%	14,4%
All months ekskl. El Nino Months	9,9%	42,2%	12,6%	45,7%	17,5%	48,8%	21,8%	21,0%	30,4%	8,6%	8,5%
CREG Dry Months	21,8%	47,7%	12,6%	39,6%	32,7%	49,2%	37,8%	16,8%	36,2%	1,6%	19,3%
All months ekskl. CREG Dry Months	9,9%	39,5%	20,2%	46,3%	17,5%	47,3%	17,1%	25,2%	28,5%	11,4%	3,3%

Portfolio - GTPE: 560MW & Wind Production with same CEN

	ENFICC_base / NCF						ENFICC_95%			Diff. ENFICC_95%	Diff. ENFICC_95%
	Wind		Hydro		W & H		Wind	Hydro	W & H	Wind vs. W&H	Wind vs. W&H
All months	9,9%	43,0%	10,8%	59,0%	22,3%	55,0%	22,5%	22,0%	35,0%	12,5%	13,0%
El Nino Months	16,3%	45,3%	22,6%	54,5%	34,3%	55,1%	28,8%	24,5%	36,8%	8,0%	12,2%
All months ekskl. El Nino Months	9,9%	42,2%	10,8%	60,0%	22,3%	55,0%	21,8%	20,8%	33,6%	11,8%	12,8%
CREG Dry Months	21,8%	47,7%	16,3%	64,5%	31,0%	61,6%	37,8%	30,4%	42,4%	4,6%	12,0%
All months ekskl. CREG Dry Months	9,9%	39,5%	10,8%	54,0%	22,3%	51,6%	17,1%	20,7%	33,5%	16,4%	12,8%

Portfolio - GVIO: 1200MW & Wind Production with same CEN

	ENFICC_base / NCF						ENFICC_95%			Diff. ENFICC_95%	Diff. ENFICC_95%
	Wind		Hydro		W & H		Wind	Hydro	W & H	Wind vs. W&H	Wind vs. W&H
All months	9,9%	43,0%	17,1%	50,6%	21,8%	51,6%	22,5%	27,3%	33,2%	10,7%	5,9%
El-Nino Months	16,3%	45,3%	17,1%	49,4%	33,1%	52,4%	28,8%	21,1%	34,0%	5,2%	12,9%
All months ekskl. El-Nino Months	9,9%	42,2%	23,3%	50,7%	21,8%	51,3%	21,8%	28,3%	32,2%	10,4%	4,0%
CREG Dry Months	21,8%	47,7%	19,5%	48,2%	28,2%	53,4%	37,8%	25,6%	37,7%	-0,1%	12,1%
All months ekskl. CREG Dry Months	9,9%	39,5%	17,1%	52,0%	21,8%	50,2%	17,1%	28,3%	32,1%	15,0%	3,8%

Some general trends can be identified from the above summary tables.

- Portfolio impact on $ENFICC_{95\%}$
  - A general rule (applies for almost all scenarios) is observed. $ENFICC_{base}$ and $ENFICC_{95\%}$ for the wind/hydro portfolio are larger than either the separate wind and hydro production units

  - Time span – All months
    $ENFICC_{95\%}$ increases between 3,8% and 12,5% when separate wind and joint wind/hydro production are compared.

    Trend: The ENFICC increases when the portfolio is compared with the separate wind or hydro production units.

  - Time span – El-Niño only
    All portfolios (except the 285MW unit case) have a $ENFICC_{95\%}$ increase between 1,3% …8,0% when separate wind and joint wind/hydro production is compared.

    Trend: The ENFICC increases when the portfolio is compared with the separate wind or hydro production units.

- Time span – CREG dry only
  The change in $ENFICC_{95\%}$ varies -1,6% and 4,6% when separate wind and joint wind/hydro production is compared.

  Trend: None

6.6 Conclusions

6.6.1 ENFICC – Wind Farms

CREG's approach for determining the Firm Energy Factor for wind energy does not consider the complementarity between the hydro and wind energy production.

Based on the Firm Energy Factors (calculated in compliance with the methodology currently used by CREG with wind data series established) for all months and the months with low water resources the following conclusions can be drawn up:

- The ENFICC calculated for the new and larger wind turbines indicates significant higher figures than CREG assumes today ($ENFICC_{base}$ = 6% and $ENFICC_{95\%}$=7,3%).
- ENFICC calculated
  All months timespan: $ENFICC_{base}$ ≈10% and $ENFICC_{95\%}$ ≈23%
  El-Niño months time span: $ENFICC_{base}$ ≈16% and $ENFICC_{95\%}$ ≈29%
  CREG dry months time span: $ENFICC_{base}$ ≈22% and $ENFICC_{95\%}$ ≈39%
- Wind turbine impact on $ENFICC_{95\%}$ (1.3MW →3,0MW)
  All months time span: ≈ +6%
  El-Niño months time span: ≈ +8%
  CREG dry months time span: ≈ +10%
- El-Niño & CREG dry month impact on $ENFICC_{95\%}$
  Only El-Niño months timespan compared with All months: ≈ +5...6%
  Only CREG dry months timespan compared with All months: ≈ +12...16%

Based on above an adjustment (≈ +10…20%) of the $ENFICC_{95\%}$ figures for an isolated wind farm previously being based on the Jepirachi 15x1,3MW wind farm can be augmented since:

1. The wind turbine units installed are larger today resulting in an $ENFICC_{95\%}$ increase ≈+6..10%.
2. $ENFICC_{95\%}$ is higher (≈ +5…6%) during the El-Niño months with relatively less water resources.
3. $ENFICC_{95\%}$ is higher (≈ +12…16%) during the GREC dry months with relatively less water resources.

7 Portfolio impact on reliability charge & regulatory scheme

The ENFICC simulations conducted in this study are based on energy production from wind farms calculated and the actual reported production from four selected hydro power plants. The hydro power plants are all with a dam/reservoir. Analysing of the dam/reservoir impact on the ENFICC falls outside this study. Consequently only general trends have been investigated.

The portfolio impact on ENFICC when each of the selected hydro production units are analysed does not show a clear and aligned trend. The table below summarise the portfolio impact on the ENFICC and NCF when all the four hydro units are joint in one production pool together with an equal wind power production plant.

Portfolio - All units: 2585MW & Wind Production with same CEN

	ENFICC_base / NCF						ENFICC_95%			Diff. ENFICC_95% Wind vs, W&H		Diff. ENFICC_95% Wind vs, W&H	
	Wind		Hydro		W & H		Wind	Hydro	W & H				
All months	9,9%	43,0%	24,5%	50,1%	28,3%	51,4%	22,5%	34,1%	34,4%	11,9%		0,4%	
El-Nino Months	16,3%	45,3%	24,5%	45,6%	31,4%	50,5%	28,8%	27,2%	35,2%	6,4%		8,0%	
All months ekskl. El-Nino Months	9,9%	42,2%	29,6%	51,3%	28,3%	51,6%	21,8%	37,9%	33,5%		11,7%		-4,4%
CREG Dry Months	21,8%	47,7%	24,5%	50,8%	37,5%	54,7%	37,8%	33,1%	41,6%	3,8%		8,4%	
All months ekskl. CREG Dry Months	9,9%	39,5%	27,4%	49,5%	28,3%	49,0%	17,1%	36,5%	31,9%		14,8%		-4,5%

As a general rule (applies for almost all scenarios) it is verified that $ENFICC_{base}$ and $ENFICC_{95\%}$ for the Wind/Hydro portfolio are larger than either the separate wind or hydro production units.

Portfolio impact on $ENFICC_{95\%}$			
	2585 MW Portfolio	**285/540/560/1200MW Portfolios**	**Portfolio Trend *)**
Compared Wind vs. Wind/Hydro Portfolio			
All month	11,9%	3,8% .. 12,5%	≈ +8%
El-Niño month	6,4%	1,3% .. 8,0%	≈ +5%
CREG dry month	3,8%	-1,6% .. 4,6%	≈ +3%
Compared Hydro vs. Wind/Hydro Portfolio			
All month	0,4%	5,9% .. 13%	≈ +9%
El-Niño month	8,0%	10,9% .. 14,4%	≈ +12%
CREG dry month	8,4%	12% .. 17,5%	≈ +8%

*) The table above shows a preliminary summary of the $ENFICC_{95\%}$ impact when wind/hydro portfolio's are investigated.

It must be stressed that the above finding are speculative and there is a need for further investigations to confirm this trend.

- The actual production pattern of each of the selected hydro power plants are different and influenced by dam/reservoir operation and even commercial/market conditions that are not investigated in this study.

- The ENFICC related to the separate hydro units appears to be too low figures. Thus the ENFICC figures calculated for the wind/hydro portfolio are influenced and should not be taken for accurate figures).

8 Review of international experiences

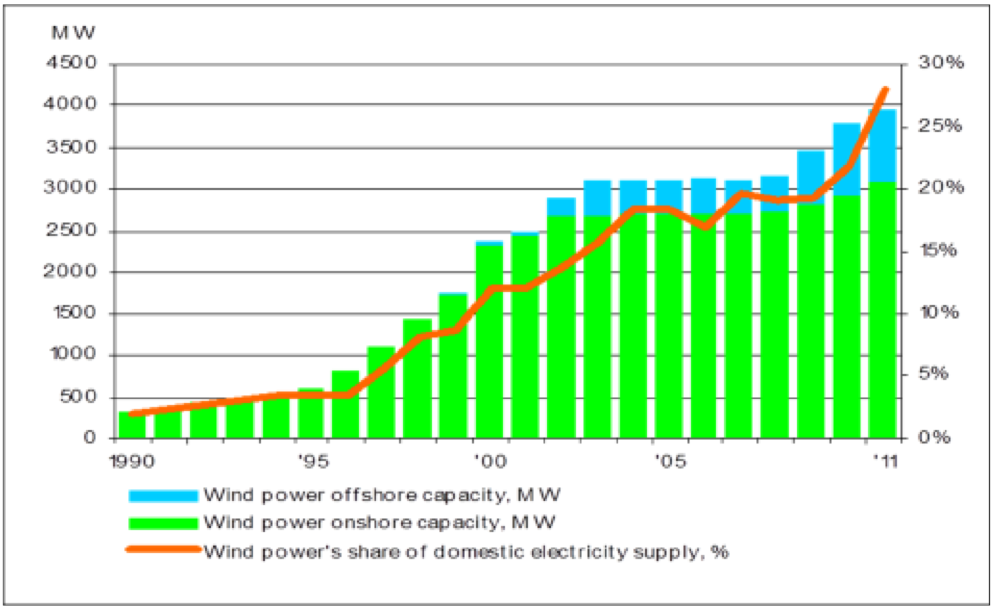
8.1 Denmark

8.1.1 Wind power in Denmark and current rules/conditions

Denmark has approximately 4,000 MW wind turbines installed and an annual electricity demand of approximately 32 TWh. The wind turbines cover as much as 25-30 % of the annual electricity demand.

The figure below shows the development in installed wind power capacity from 1990 to 2011 and the wind power's share of domestic electricity supply.

Figure 3: Wind power capacity and wind power's share of domestic electricity supply



Source: The Danish Energy Agency

In Denmark, onshore wind turbines in general receive the market price of electricity plus an add-on to the market price. The add-on to the market price is 250 DKK/MWh and is paid for the first 20,000-25,000 number of full load hours which corresponds to app. 6-10 years (after this period, the wind turbines only receive the market price). By high market prices, however, the add-on is reduced so that the total price within each month (market price + add-on) cannot exceed 580 DKK/MWh.

For off-shore turbines, there are some other rules/conditions. They are built based on government tender and they receive a fixed agreed price per MWh. The prices for the three newest off-shore parks are:

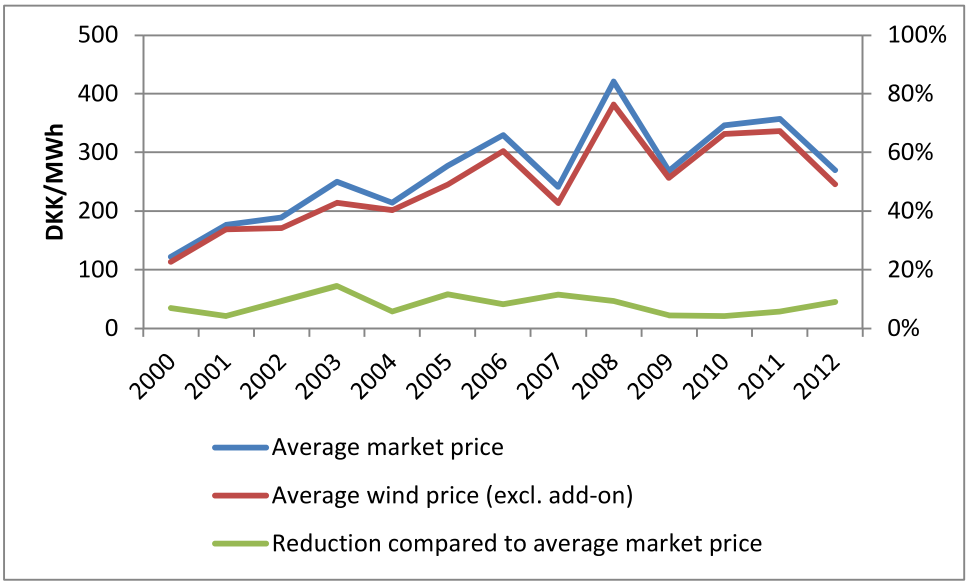
- Horns Rev 2 tendered the 7th of July 2004 – 518 DKK/MWh.
- Rødsand 2 tendered the 7th of February 2008 – 629 DKK/MWh.
- Anholt tendered the 30th of April 2009 – 1051 DKK/MWh.

The fixed agreed paid price per MWh is paid for the first 22,000 full load hours. After this, the off-shore turbines receive only the market price.

Figure 4 below shows the development in the annual average market price from z<

2000 to 2012 (blue line). It also shows the average price paid to the wind producers excluding the add-on of 250 DKK/MWh (red line).

Figure 4: Average market price and average wind price in western Denmark



From Figure 4 it appears that the wind operators in average receive a price (excluding the add-on) which is almost 10 % lower than the average market price. This has to do with the so-called merit order effect, i.e., the wind turbines are themselves influencing the price in downwards direction.

8.1.2 System integration of wind power

The main challenge with regard to system integration of wind power is to ensure that power demand is met at all times as the wind power production fluctuates as the wind blows. The traditional power generators, like hydro, thermal and nuclear are more predictable and stable in their production patterns than wind power. Furthermore, wind power is often also more decentralised with many and relative smaller production units posing a challenge of having a larger number of installations to work with. The Danish experience shows that the variable and decentralised production can be handled, while still maintaining an efficient and resilient power sector with very high security of supply.

Long term planning and a stable and supportive policy framework in Denmark have been key to the successful large scale integration of wind power in distribution and transmission networks. The aim has been to transmit power most efficiently and with least associated costs from the production sites to the demand centres. The political framework embraces a range of issues such as common goals or targets, design of taxes and incentives for developers as well as regulation and legislation to ensure well-functioning market conditions that stimulate investments.

System operation and the power market represent the two central pillars on which the successful Danish integration of wind power has been built:

- System operation with accurate wind forecasts and adequate reserve capacity for periods with little wind and a demand side that automatically adapts in situations where there is too little or excess production from wind power.

- A well-functioning power market – in which players trade themselves into balance, i.e. supply equals projected demand (intra-day market) and a market for balancing power (the regulating power market) operated by the TSO

Grid connection and its finance

Within grid connection and its finance, key points and recommendations from the Danish case are:

- Wind power like all other power generators need grid connection. It is important to ensure the needed grid investments is in place in due time and to give the grid operators incentives to finance the needed grid connection and enforcements, and the needed ancillary services.

- Large wind farms need to be connected to the transmission grid.

- Priority access is a guaranty to wind power producers that they will have access to sell their power in the market place at all times.

- Consider the appropriate financing model for grid connection of wind power (e.g. cost sharing between grid companies and developers).

Transmission and interconnector capacity

Within transmission and interconnector capacity, key points and recommendations from the Danish case are:

- Interconnectors to neighbouring countries with balancing power (e.g. hydro power) should be considered and pursued.
- Interconnectors help the spreading of fluctuating wind power to a larger area/market, thus making it easier to integrate

Forecasting

Within forecasting, key points and recommendations from the Danish case are:

- Reliable wind power forecasts help the TSO in the overall system operation and the integration of wind power.
- Forecasts should be regularly updated (e.g. every six hours).
- Forecasts should be linked to the market place and be an integrated part of the functioning of the market.
- The Danish case shown high certainty in forecasts and underline that they are an important tool for day-to-day and hour-to-hour planning and system operation.

Technical Regulation

Within technical regulation, key points and recommendations from the Danish case are:

- Technical regulation must be in place in appropriate detail to ensure the physical grid functioning and system security

Grid Codes

Within grid codes, key points and recommendations from the Danish case are:

- Grid codes could be designed to require wind turbines to e.g.:
  - Disconnect during abnormal voltage and frequency events
  - Remain connected to the grid in case of fault
  - Be controllable remotely
  - Curtail if necessary

Market

Within market, key points and recommendations from the Danish case are:

- A liberalised market is recommendable as it balances supply and demand according to the merit order through the price signal and thereby reduces power production and system operation costs (alternatively, the optimal merit order should be obtained in another way)

- Unbundling of generation and transmission will ensure that transmission companies do not have commercial interests in the production side and thus eliminates associated market risks and creates a level of playing field for all power producers.

- A large market area allows for greater integration of wind power.

Key messages

The policy tools and measures in the Danish case and the related opportunities and barriers are not unique to Denmark. The tools and measures may, when adjusted to specific national circumstances, be applied by all countries that are about to integrate variable power sources, such as wind power, into the overall power grid and system.

Integration of variable renewables into the grid is sometimes misleadingly presented as an insurmountable task. The Danish case proves this is wrong. Not only is an effective and cost-efficient integration of wind power feasible, it can also improve energy security through diversification of the energy mix and through decentralisation and geographic scattering of power generators.

Central and long-term planning has been one of the trademarks of the Danish case and has ensured timely and relevant investments in the power grid and system. Thus, the grid and system have been developed incrementally in order to make them more adapt to handle the steadily increase in wind power production.

Today the strategic planning of future grid investments follow the current political energy agreement with adopted measures and policies toward 2020 as well as the Danish long-term goal of full conversion to renewable energy in 2050. Naturally, such future benchmarks give guidance on the appropriate and cost-efficient transition of the power grid and system from being based on traditional fossil fuels and toward a steadily greater renewable energy base.

8.2 South Africa

South Africa's steady economic growth as it increasingly focuses on industrialisation, together with its mass electrification programme to take power into deep rural areas, has seen a steep increase in the demand for electricity. In fact, South Africa's energy demand is expected to be twice the current levels by 2030.

Years of underinvestment in the country's power infrastructure has meant that energy demands are rising faster than Eskom, the state-owned company in charge of the majority of energy generation and distribution, can meet them.

Together with Eskom, the government's Department of Energy has embarked on a massive programme to bring the electricity supply and distribution system into balance. With an infrastructural price tag of around R340-billion, Eskom is building new power stations, including Medupi in Limpopo that will make its first contribution to the grid by 2013, and Kusile, which will come on stream in mid-2014.

South Africa, which has always been heavily dependent on coal, is looking at ways to diversify its power-generating capacity. The African Development Bank, the Treasury and Eskom are working on a renewable energy programme that involves independent power producers.

The government is also looking to support sustainable green energy initiatives on a national scale through a diverse range of clean-energy options as envisaged in the Integrated Resource Plan 2010. In terms of this plan, which is a 20-year projection on electricity demand and production, about 42% of electricity generated must come from renewable resources.

Integrated Resource Plan (IRP)

On 17th March 2011, South Africa approved its Integrated Resource Plan (IRP) for the energy sector. The plan outline is the government's strategy for electricity generation in the country to 2030. The planning scenario is based on growth in gross domestic product (GDP) averaging 4.5% over the next 20 years which will require 41,346 MW of new capacity (excluding capacity required to replace decommissioned plant). A draft Independent System and Market Operator Bill was also tabled in parliament, which would facilitate participation of independent power producers (IPPs) in electricity generation in South Africa.

Energy from renewable sources will be expected to make up a substantial 42% of all new electricity generation in South Africa over the next 20 years, following Cabinet approval of the country's Integrated Resource Plan 2010.

Under the approved IRP 2010, nuclear is expected to make up 23% of all new electricity generation (down from 25% in the draft IRP), coal 15% (down from 16%), open-cycle gas turbines 9% (down from 15%), hydro power 6% (down from 9%), and imported gas 6% (up from 5%).

Renewable Energy Independent Power Producer Procurement Programme

South Africa has a high level of Renewable Energy potential and presently has in place a target of 10,000 GWh of Renewable Energy. The Minister has determined that 3,725 MW to be generated from Renewable Energy sources is required to ensure the continued uninterrupted supply of electricity. This 3,725 MW is broadly in accordance with the capacity allocated to Renewable Energy generation in IRP 2010-2030.

The IPP Procurement Programme has been designed to contribute towards the target of 3,725 MW and towards socio-economic and environmentally sustainable growth, and to start and stimulate the renewable industry in South Africa. The programme provides incentive to Independent Power Producers (IPPs) to invest in developing sustainable renewable energy sources.

South Africa originally launched the new energy procurement program using renewable energy feed-in tariffs (REFITs). However, it never took off in South Africa, which eventually modified its program to rollout with renewable energy bids (REBID).

The first three bidding rounds, two completed and the third underway, are for a capacity of 3,625 MW:

- On shore wind (1,850 MW)
- Concentrated solar thermal (200 MW)
- Solar photovoltaic (1,450 MW)
- Biomass solid (12,5 MW)
- Biogas (12,5 MW)
- Landfill gas (25 MW)
- Small hydro (75 MW)

In the first two rounds, a total of 2,440 MW was contracted leaving approximately 1,185 MW to be contracted in the third round. All three rounds focus on concentrated solar power, solar photovoltaic, and wind solutions.

In addition to the large IPP program, there will also be a small IPP program, which will contract about 100 MW small projects, each project having a capacity of 1-5 MW.

Wind Power and Electricity System Reliability

The power from a number of wind generators with a wide geographic spread can be included in an integrated system with a calculated capacity credit, which is the percentage of the maximum generation capacity that will replace alternative generation technologies to achieve the equivalent overall system reliability.

In South Africa, the Department of Energy (DoE) has commissioned a study on the capacity credit of wind generation in South Africa. The purpose of the study was to assess the capacity credit of planned wind farms in South Africa and the impact of wind generation on the required dynamic performance of the thermal and hydro power plants.

The analyses were carried out for different scenarios and by use of a Monte Carlo analysis approach considering:

- Daily peak load characteristics
- Planned and unplanned outages of conventional generators
- Correlation of wind speed at different sites
- Daily, weekly and monthly correlation between wind speeds and the daily peak load.
- Correlation between wind speeds and daily full load hours

The study has shown that besides contributing to the electrical energy supply, wind turbines can also have a valuable contribution to the equivalent firm capacity of a system. This means in other words, that with the addition of wind farms, the reliability of supply of a system is improved and that it is indeed possible to replace some conventional power plants by wind farms completely.

The conclusion was that the sites with best wind conditions may not be developed first, but factors such as surrounding infrastructure may be just as important in project developments. When considered in connection with a typical coal fired power station in South Africa, results showed that to have the same effect on generation capacity, the installed capacity of a wind farm must be approximately 3 to 4 times higher than the installed capacity of a coal fired plant. Overall, for a wind generation plant in South Africa, the capacity credit of wind generation will be between **25 % and 30 %** for installed wind generation of up to 10,000 MW. In the case of higher wind penetration (25,000 MW), the capacity credit of wind generation in South Africa will drop below **20 %**.

The wind penetration levels of the different scenarios varies between around 5 % and 20 % (based on peak load), which can be considered to be moderate, even in the scenario with 20 % penetration.

9 Wind energy integration strategies

The wind study of the La Guajira wind farm (separate report) has shown good wind resources resulting in a relatively high annual energy production from the wind farm. The financial feasibility analyses, however, have shown that the levelized cost of energy (LCoE) are only slightly higher, and in some cases even lower, than the current average sales price assumed to US$ 65 per MWh. This means that the IRR becomes close to or even less than the base rate from the Central Bank of Colombia of 3.25 %, which is far below the rate, that developers expect.

This means that the wind power project in La Guajira is not considered financially viable. However, the analyses have also shown that the IRR is very sensitive to changes in the tariff and the investment cost. If either the tariff is increased by 10-20 % or the investment costs could be lowered by 10-20 %, the IRR will reach a level within the range that developers expect.

This also means that the wind power development in Colombia **could possibly be boosted** if there was either a feed-in tariff of 10-20 % of the sales price or an investment grant of 10-20 % of the investment.

The potential for wind power in Colombia is 18 GW which is 900 times as much as the current capacity of 20 MW. It should be decided whether this wind power potential, or some of it, is wanted to be utilised and if so, the necessary support mechanisms should be put in place.

9.1 Benefits of wind power

The benefits from wind farm developments include:

- They contribute to national and international efforts to reduce emission of greenhouse gases and other air pollutants through potential displacement of those created by conventional thermal power sources.
- They improve sustainable power generation.
- They increase energy diversity.

- They reduce regional and national dependency on fossil fuels.

- In a Colombian context, wind turbines can also contribute to system reliability during periods of el Niñjo where drought substantially reduces hydroelectric generation. In these periods, the generation from wind turbines will not be lower than in other periods; on the contrary, it seems that it will be slightly higher.

- Wind farms may also improve energy security through decentralisation and geographic scattering of power generators

9.2 Key issues

In addition to the financial aspect as mentioned above and the need for support mechanisms if the large wind power potential in Colombia is wanted to be utilised, the following two main issues should be addressed:

- Administrative and grid access barriers

- System operation including forecasting

9.2.1 Administrative and grid access barriers

In Europe, the European wind energy association, EWEA, has carried out a study which identifies barriers that compromise the development of wind energy, with respect to administration and grid connection.

Five main factors have been identified through the study as being barriers to grid access and connection:

1 Grid connection lead time

2 Grid connection costs

3 Transparency of decision making process and deadlines

4 Number of system operator and number of parties involved

5 Physical grid access

The factors are described below. In order to utilise the wind power potential in Colombia, the wind energy integration strategy should also deal with these factors.

Grid connection lead time

Grid connection lead time is often high because of the grid connection procedures. This can be due to a number of factors including poor administration servants, poor administrative deadlines and inadequately defined grid infrastructure. In the EU the average grid connection lead time is 25.8 months for onshore and 14 months for offshore.

EWEA Recommendations:

- Reduce average grid connection time to 6 months
- Set and adhere to strict deadlines for administration processes
- Train and allocate sufficient personnel to manage the anticipated applications
- Provide well-defined requirements for grid connections and capacities at common coupling points to the public
- Assign connection points to technically reliable projects over poorly designed
- Closer collaboration of developer and grid operators
- Reducing excess of developer requests on grid points by ensuring projects put up for application are realistic and based on measured wind data

Grid connection costs

The grid connection costs here include those for grid extensions, staff and administrative procedures. In some countries, investment risks become high where grid cost information is not well defined or provided early enough in the development process. What's more, member states have different regulations on the share of grid connection costs between system operators and developers, which can limit access for some developers. Reports in some EU countries show that connection costs can have significant differences depending on the distribution company, which can affect grid access for developers.

EWEA Recommendations:

- System operators should cover and/or contribute to the costs of grid connection; protocol defined for this procedure
- System operators should adapt costs to the project size
- Limit technical grid connection requirements to what is necessary within the scope of a project
- Better definition (and eventually EU standardization) of grid codes and connection requirements, which are realistic and correspond with the latest technologies; these are available to developers

Transparency of grid connection process

Grid connection transparency reflects greatly in standards for accessibility to grid connection data, deadlines for the grid connection process, consistency of decision making for allowing connection and collaboration between parties involved. Connections requests would benefit from better coordination between distribution and transmission companies. Grid access would be also fairer where vertical integration of power companies is broken down in some EU countries.

Number of system operators and number of parties involved

In the EU the average number of transmission system operators involved in wind developments is 0.85 for onshore and 0.92 for offshore, which means that a majority of developments in many countries connect to a single transmission grid. The average number of parties involved in the grid connection procedure in the EU is 24 for onshore and 4.4 for offshore wind. The ideal objective for the EU would be coordination of the application process through a single access point. Currently the best performing countries in the EU have an average of fewer than three entities to contact. For countries where the averages are higher there is concern for clarity in administrative procedure, appropriate interlocutors and the overall decision making processes for grid access procedures.

Physical grid access

In many European countries the grid is underdeveloped in windy areas and/or not capable of integrating large amounts of wind power. This causes problems with grid access where developers have to wait longer to get physical connection to the grid. Farming projects can also be compromised where plants cannot be placed in ideal locations due to this insufficient grid capacity. This supports the need for sufficient funding by and collaboration with the grid operators or energy companies to resist such barriers and provide necessary grid extensions.

A note should also be made on the relation between grid access and access to land for grid connections. It is often the responsibility of the developer to set up evacuation lines connecting the wind park and connection point. In some countries, a parallel project with environmental impact assessment studies must be established in gaining approval for this.

Similar access barriers are experienced throughout the EU. The following table also highlights a few and which are most relevant for different regions:

9.2.2 System operation including forecasting

The nature of wind power is that it is produced when the wind blows and not in correlation to ongoing power consumption. The unpredictability of wind power makes it necessary to have the capability to regulate both up and down to accommodate deviations in wind power forecasts.

An effective operation of the power system can make the system more adaptable to larger shares of variable renewable power.

Transmission and interconnection capacity

A strong transmission and distribution grid with strong interconnections to neighbouring power systems/markets is an important element in large scale wind deployment.

Forecasting

Wind forecasts are used to calculate how much wind power the wind turbines will generate, e.g. minute by minute. With increasing amounts of wind power in the system, accurate forecasting will become more and more important.

Technical regulation and grid codes

The technical regulations help ensuring the physical operation of interconnected high-voltage grids and system security. Technical regulation including the requirements that a wind farm must meet at the connection point must be in place in appropriate detail to ensure the physical grid functioning and system security.

10 List of references

1. CREG 2006. "*Reliability charge – Regulatory scheme to guarantee the reliability in the supply of electric energy in Colombia, a long-term vision*".

2. Isaac Dyner et. al. 2011. *"An enabling framework for wind power in Colombia: what are the lessons from Latin America?"*. July 2011

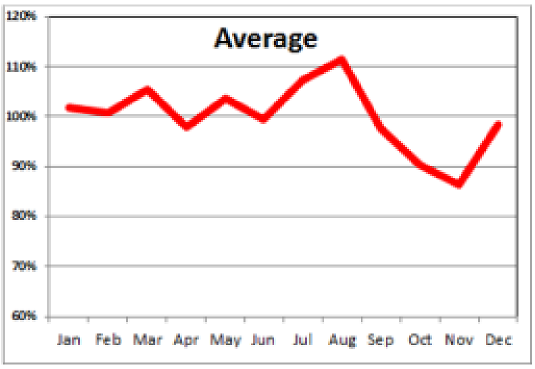
3. Ministry of Mines and Energy. *"The Reference Expansion Plan, Generation – Transmission, 2006-2020"*.

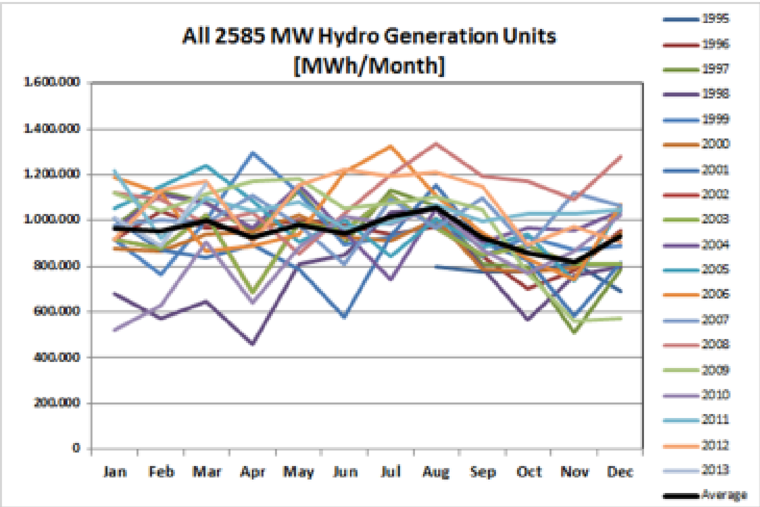
4. Oxford Institute 2012. *"Private Investment in Wind Power in Colombia"*. A report commissioned by the UK Foreign and Commonwealth Office's Latin America Prosperity Fund. July 2012.

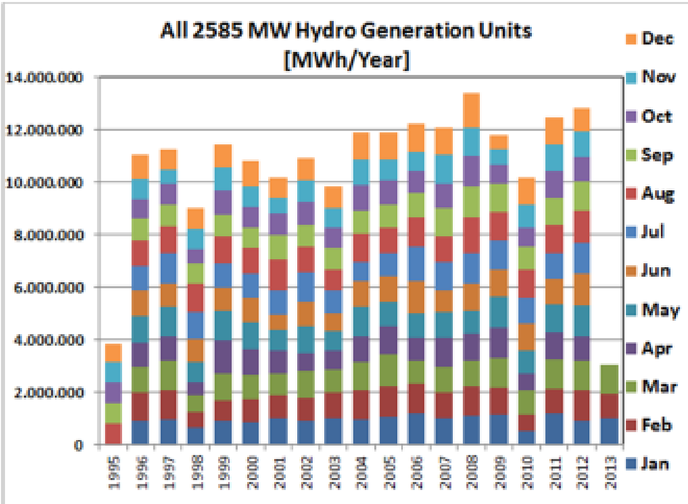
5. World Bank. *"Wind Energy in Colombia, A framework for Market Entry"*. The World Bank. Washington, D.C. July 2010.

6. Ministerio de Minas y Energia, Resolucion No. 148, 21 Oct 2011

Appendix A All units 2.585 MW Hydro Production



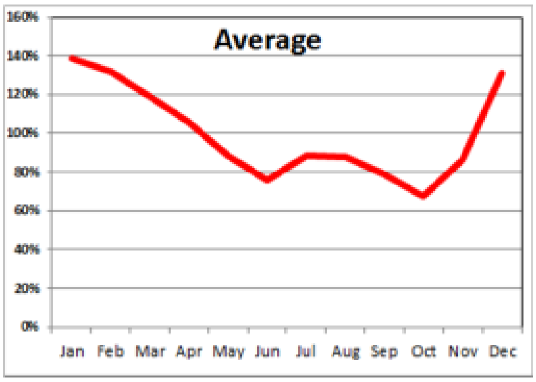


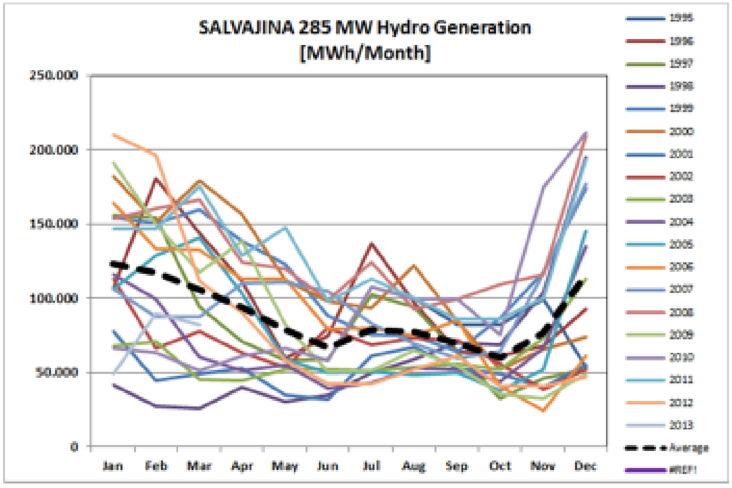


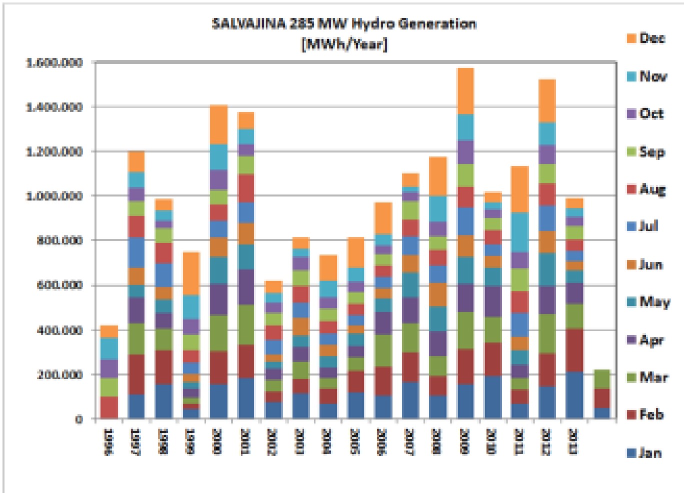
Energy produktion [kWh/month]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1995								797.960	774.336	773.678	814.517	691.335	3.851.826
1996	919.356	1.043.482	967.842	969.702	999.147	981.424	938.329	973.790	842.975	702.533	781.489	957.274	11.077.343
1997	970.830	1.125.625	1.078.983	943.046	1.129.258	902.392	1.131.239	1.064.935	808.014	796.038	509.955	785.044	11.245.360
1998	679.809	571.343	647.528	456.886	811.060	847.828	1.035.898	1.054.743	791.695	568.968	756.954	797.336	9.020.048
1999	914.329	766.157	1.003.812	1.298.006	1.118.219	893.689	929.716	990.445	845.211	926.583	872.970	889.206	11.448.341
2000	874.714	866.724	940.143	948.205	1.023.667	930.532	910.548	1.009.218	784.924	773.163	790.158	945.857	10.797.854
2001	1.005.382	869.039	839.148	892.924	785.071	576.651	935.393	1.151.643	907.711	827.256	585.894	814.541	10.190.651
2002	919.680	876.500	1.024.620	686.778	989.868	956.055	1.110.226	968.376	848.441	889.158	810.134	810.284	10.890.118
2003	988.203	973.221	898.268	730.150	726.670	678.391	868.997	818.897	799.258	792.312	741.131	825.694	9.841.191
2004	959.727	1.112.095	1.074.453	968.225	1.154.173	949.699	743.720	1.051.774	903.909	967.504	958.809	1.040.014	11.884.102
2005	1.053.963	1.149.652	1.236.898	1.084.738	903.006	1.003.669	845.047	1.008.507	883.095	938.506	734.120	1.049.881	11.891.082
2006	1.185.826	1.123.055	866.006	887.225	942.455	1.211.319	1.325.982	1.107.742	945.247	834.148	742.321	1.070.258	12.241.584
2007	980.851	1.001.952	989.759	1.107.028	978.548	811.309	1.090.798	969.080	1.099.409	885.886	1.121.586	1.064.133	12.100.339
2008	1.118.836	1.095.044	982.192	1.034.734	853.920	1.032.303	1.198.435	1.334.069	1.193.206	1.171.037	1.089.933	1.277.240	13.380.951
2009	1.122.946	1.041.846	1.113.164	1.173.483	1.183.105	1.051.637	1.076.789	1.105.021	1.045.073	770.262	559.779	571.790	11.814.894
2010	522.752	627.921	907.549	642.708	883.199	1.019.232	984.349	1.059.232	871.645	767.949	866.364	1.023.005	10.175.905
2011	1.214.475	921.832	1.098.252	1.039.672	1.079.541	969.884	990.764	1.071.978	996.796	1.029.334	1.030.960	1.048.133	12.491.620
2012	917.118	1.131.059	1.170.708	905.333	1.151.865	1.220.594	1.196.285	1.211.113	1.150.337	894.472	972.863	904.720	12.826.466
2013	1.015.157	890.964	1.160.067										3.066.189
	Average												
	964.664	**954.862**	**999.966**	**927.579**	**983.104**	**943.330**	**1.018.383**	**1.055.915**	**924.526**	**855.006**	**819.142**	**933.789**	**948.356**
	% of Yearly Average												
	102%	**101%**	**105%**	**98%**	**104%**	**99%**	**107%**	**111%**	**97%**	**90%**	**86%**	**98%**	

Appendix B SALVAJINA 285 MW Hydro Production

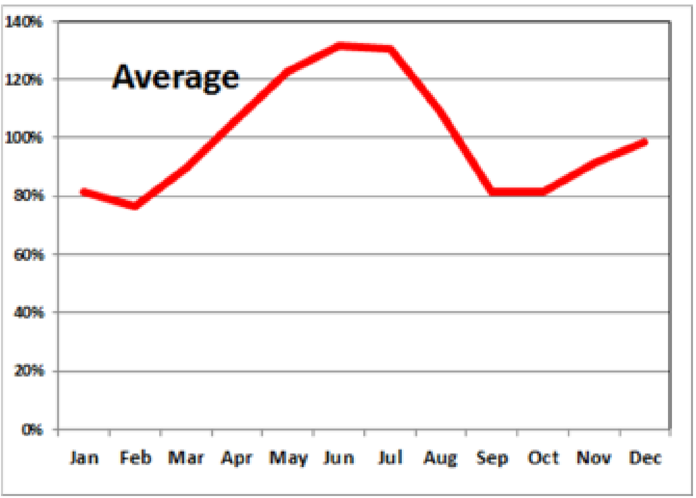


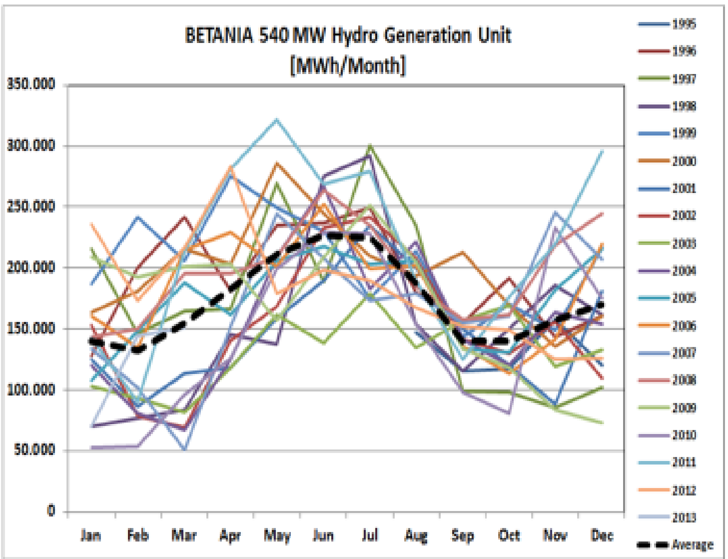


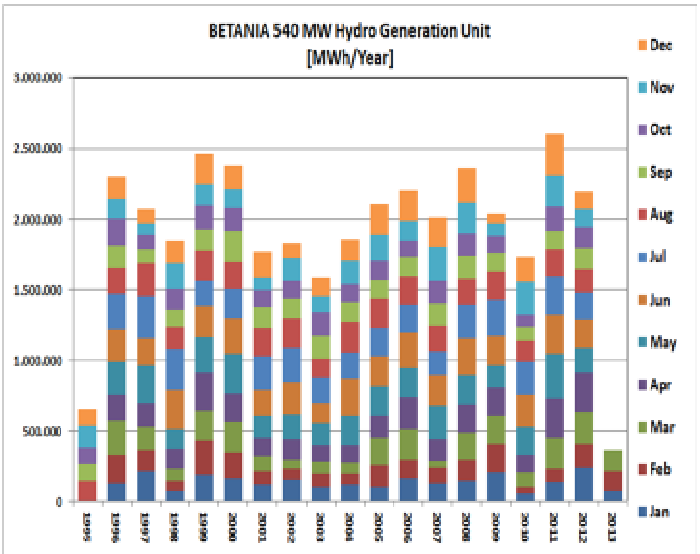


	Energy produktion [kWh/month]												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
1995	[redacted]							100.568	82.558	82.556	99.727	53.530	418.938
1996	107.210	180.261	143.511	111.831	59.600	74.879	137.113	97.232	64.135	61.039	68.255	92.896	1.197.963
1997	155.926	154.519	94.196	70.667	58.193	59.243	102.738	94.234	63.514	32.417	46.475	52.152	984.274
1998	41.910	27.466	26.140	40.450	30.052	34.845	50.030	59.228	69.836	68.868	103.928	194.850	747.602
1999	154.267	150.855	159.481	138.285	122.877	88.001	75.437	74.816	64.200	86.761	117.274	173.794	1.406.047
2000	181.691	151.585	179.218	156.743	112.583	97.887	93.668	122.140	84.547	52.236	65.905	74.255	1.372.458
2001	77.764	44.659	49.321	52.546	34.595	32.026	61.435	67.371	53.233	48.917	39.823	54.948	616.639
2002	112.892	66.251	77.562	63.340	53.935	80.225	68.510	73.065	71.332	56.257	38.633	52.403	814.404
2003	67.906	71.017	45.531	44.313	52.165	52.036	51.530	53.376	56.274	52.352	73.489	112.648	732.636
2004	116.063	99.269	60.190	51.330	54.802	39.524	43.285	52.825	52.383	43.898	66.476	134.470	814.515
2005	106.529	128.731	140.880	103.262	59.074	49.892	50.468	48.425	49.961	37.954	52.434	145.274	972.885
2006	163.915	133.221	132.814	113.239	113.225	79.481	80.087	74.968	85.100	41.063	24.182	61.496	1.102.790
2007	106.539	87.761	87.351	110.301	110.803	104.984	82.696	69.414	59.627	63.896	116.390	177.025	1.176.789
2008	153.705	160.433	166.557	124.309	120.004	98.710	124.499	92.661	99.606	109.117	115.901	208.788	1.574.292
2009	191.123	149.516	117.826	138.245	82.437	50.818	51.377	64.915	54.407	35.995	32.601	49.346	1.018.605
2010	66.787	63.688	51.189	61.051	66.709	58.224	107.483	99.404	99.386	75.585	174.764	211.018	1.135.287
2011	146.655	146.883	175.474	128.600	147.347	97.981	112.890	100.178	86.140	86.116	99.910	192.961	1.521.136
2012	209.913	196.482	111.249	90.690	58.139	42.493	42.026	52.226	60.907	40.546	40.717	46.531	991.919
2013	49.109	89.784	82.241	[redacted]									221.134
	Monthly Average												
Average	122.772	116.799	105.596	94.071	78.620	67.132	78.545	77.614	69.842	59.754	76.494	116.021	88.605
	% of Yearly Average												
Average	139%	132%	119%	106%	89%	76%	89%	88%	79%	67%	86%	131%	

Appendix C BETANIA 540 MW Hydro Production



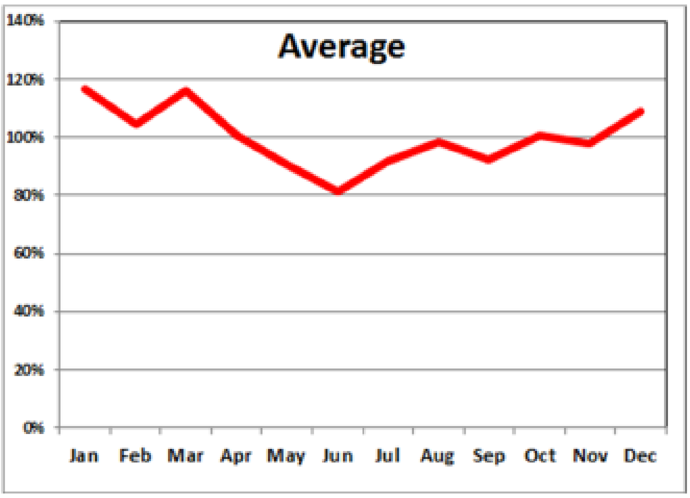


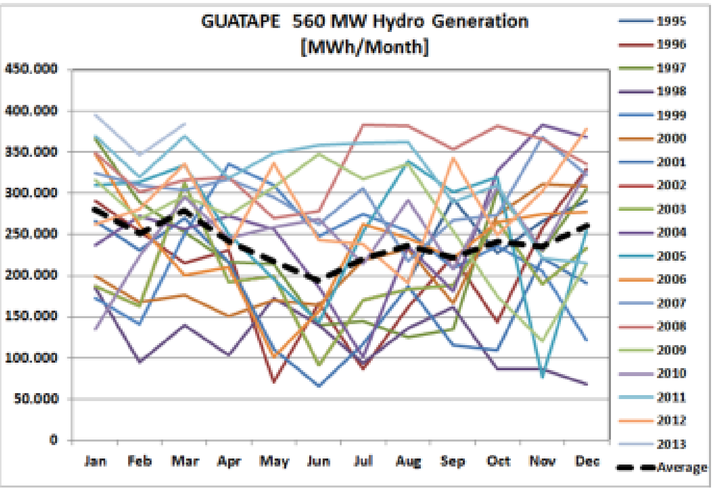


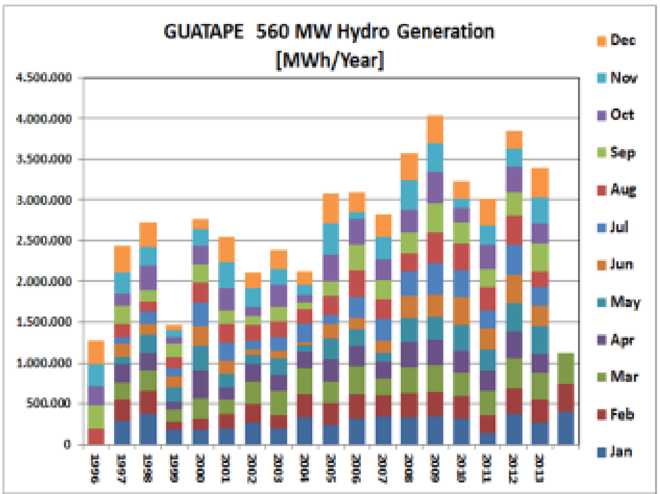
Energy produktion [kWh/month]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1995	[redacted]							147.273	115.521	117.361	157.815	120.186	658.155
1996	128.326	200.451	241.728	181.050	234.732	236.829	249.206	180.346	155.065	191.587	143.602	161.014	2.303.935
1997	215.307	146.546	164.441	166.429	269.835	188.429	300.550	234.616	98.908	97.603	85.985	101.596	2.070.245
1998	69.737	76.774	83.902	144.966	137.143	275.938	292.120	153.854	115.357	149.685	185.550	161.470	1.846.495
1999	187.220	241.566	206.399	275.246	249.468	230.374	175.213	214.228	143.734	170.050	149.206	216.403	2.459.108
2000	163.381	180.989	215.616	203.260	285.812	244.528	209.716	193.025	212.924	169.033	135.854	160.802	2.374.941
2001	124.971	86.135	113.772	117.872	158.422	189.417	234.930	199.851	150.470	120.401	88.509	180.528	1.765.279
2002	152.782	78.956	69.104	140.930	168.635	232.714	241.523	207.864	141.228	129.867	155.650	109.718	1.828.971
2003	102.452	92.883	82.048	118.381	161.991	138.958	179.385	134.215	156.880	169.724	119.295	133.078	1.589.290
2004	120.181	81.153	67.001	125.491	209.300	266.539	182.941	221.077	141.498	120.231	163.666	154.084	1.853.163
2005	107.970	147.982	187.568	161.878	206.498	217.443	203.330	205.821	133.251	130.861	181.738	215.918	2.100.258
2006	160.781	134.951	215.150	229.339	201.445	252.532	199.361	202.508	135.413	112.991	141.154	219.216	2.204.841
2007	134.146	101.613	50.767	151.919	245.070	208.305	173.546	179.328	154.892	161.092	245.241	207.390	2.013.306
2008	143.746	149.815	195.535	195.839	208.500	264.354	235.007	184.481	157.428	161.580	218.772	244.895	2.359.951
2009	209.352	192.854	201.290	203.149	157.191	209.187	251.168	205.026	133.687	118.648	83.334	72.677	2.037.561
2010	52.312	53.355	96.132	126.298	199.468	228.931	228.396	153.516	97.915	81.124	232.840	175.382	1.725.668
2011	142.325	89.890	214.034	281.675	321.567	269.055	279.384	189.282	125.063	176.166	219.452	295.554	2.603.447
2012	236.390	172.776	217.074	283.150	178.755	198.426	189.942	167.700	152.177	148.917	124.947	126.461	2.196.715
2013	70.291	144.535	151.140	[redacted]									365.966
	Monthly Average												
Average	140.093	131.846	154.039	182.757	211.402	226.586	225.042	187.445	140.078	140.384	157.367	169.799	172.236
	% of Yearly Average												
Average	81%	77%	89%	106%	123%	132%	131%	109%	81%	82%	91%	99%	

Appendix D GUATAPE 560 MW Hydro Production



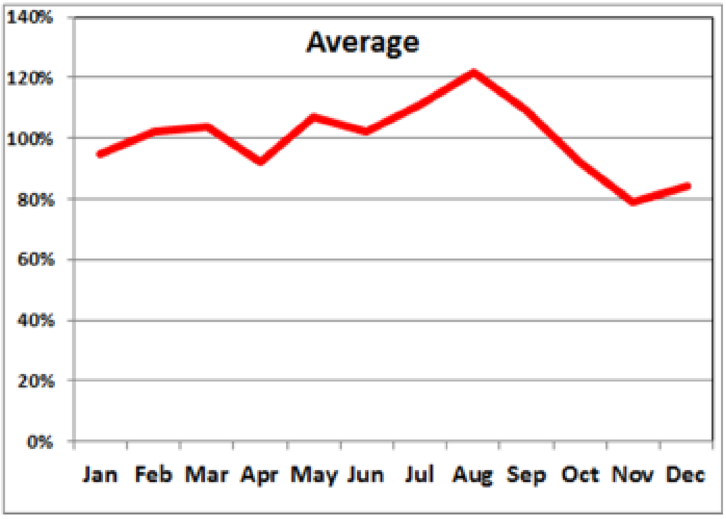


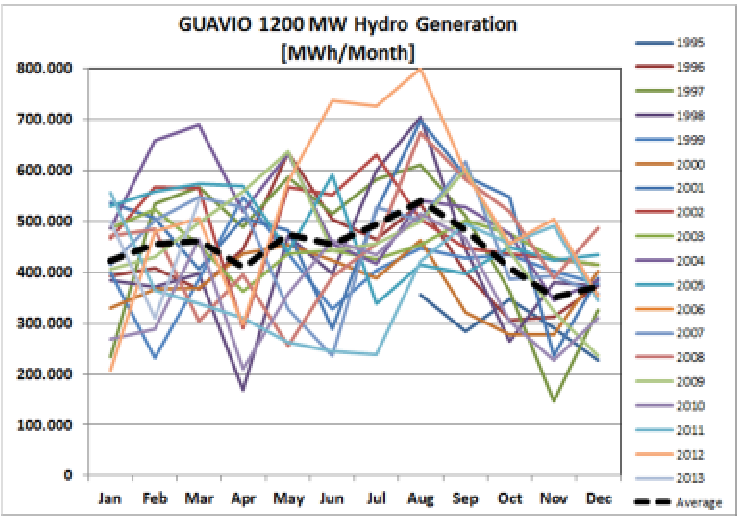


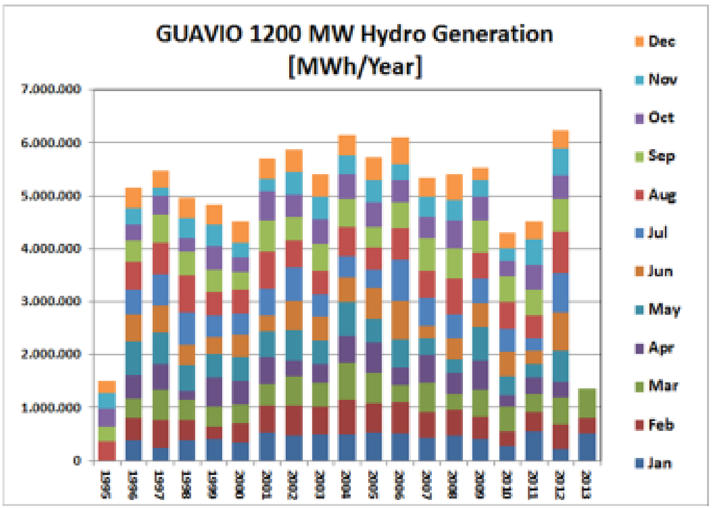
Energy produktion [kWh/month]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1995	[redacted]							193.600	293.168	227.041	266.136	291.239	1.271.184
1996	291.191	254.630	214.783	231.131	70.494	166.566	86.370	161.941	223.786	143.386	257.382	329.024	2.430.684
1997	365.757	288.880	252.776	217.030	213.930	140.030	145.241	125.186	135.182	304.577	229.965	305.516	2.724.071
1998	184.433	94.853	140.285	103.270	172.285	140.485	94.358	136.801	162.212	86.606	87.055	67.955	1.470.600
1999	172.832	141.355	250.413	335.885	309.694	247.984	275.126	254.541	209.296	235.671	205.739	122.140	2.760.676
2000	199.332	168.160	176.439	151.512	170.332	164.908	218.904	231.893	166.233	273.634	311.256	308.361	2.540.963
2001	266.408	231.681	269.605	216.556	110.597	66.179	117.113	186.956	115.188	109.442	220.818	190.979	2.101.520
2002	187.271	163.421	312.273	192.350	199.273	91.187	170.244	183.557	189.140	266.623	190.359	233.099	2.378.797
2003	331.977	285.374	317.000	205.171	76.769	43.491	213.038	177.960	84.875	94.782	121.455	164.409	2.116.300
2004	237.362	272.166	257.149	272.734	256.783	186.706	100.968	235.830	181.725	326.642	382.708	367.951	3.078.724
2005	309.822	313.938	334.117	250.939	196.183	144.198	253.221	339.453	302.062	320.172	77.019	254.004	3.095.128
2006	347.162	261.054	200.167	210.943	101.316	156.628	262.537	245.305	221.202	265.296	274.314	277.234	2.823.158
2007	325.187	309.965	304.020	317.656	296.058	262.774	306.170	217.350	267.429	273.547	367.857	322.416	3.570.427
2008	349.057	301.327	316.763	319.656	269.986	278.320	383.056	382.252	353.968	381.385	365.869	335.972	4.037.609
2009	316.465	269.270	297.297	273.104	307.328	348.097	317.452	335.732	254.806	175.386	120.292	214.145	3.229.374
2010	135.600	223.283	295.579	245.839	258.632	269.395	214.287	291.852	208.131	307.756	230.843	327.377	3.008.573
2011	369.919	320.208	369.832	319.061	348.823	358.757	360.609	361.771	289.246	310.547	220.969	215.120	3.844.862
2012	262.688	280.641	335.685	234.122	337.158	243.004	238.012	191.562	342.350	249.913	303.241	378.080	3.396.455
2013	395.590	346.169	384.471	[redacted]									1.126.230
	Monthly Average												
Average	**280.447**	**251.465**	**279.370**	**240.997**	**217.391**	**194.630**	**220.983**	**236.308**	**222.222**	**241.800**	**235.182**	**261.390**	**240.182**
	% of Yearly Average												
Average	**117%**	**105%**	**116%**	**100%**	**91%**	**81%**	**92%**	**98%**	**93%**	**101%**	**98%**	**109%**	

Appendix E GUAVIO 1200 MW Hydro Production







Energy produktion [kWh/month]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1995	[redacted]							356.520	283.090	346.720	290.840	226.380	1.503.550
1996	392.630	408.140	367.820	445.690	634.320	503.150	465.640	534.270	399.990	306.520	312.250	374.340	5.144.760
1997	233.840	535.680	567.570	488.920	587.300	514.690	582.710	610.900	510.410	361.440	147.530	325.780	5.466.770
1998	383.730	372.250	397.200	168.200	471.580	396.560	599.390	704.860	444.290	263.810	380.420	373.060	4.955.350
1999	400.010	232.380	387.520	548.590	436.180	327.330	403.940	446.860	427.980	434.100	400.750	376.870	4.822.510
2000	330.310	365.990	368.870	436.690	454.940	423.210	388.260	462.160	321.220	278.260	277.143	402.439	4.509.492
2001	536.239	506.564	406.449	505.950	481.457	289.029	521.915	697.466	588.819	548.496	236.744	388.085	5.707.213
2002	466.736	567.870	565.681	290.158	568.025	551.928	629.949	503.890	446.740	436.412	425.491	415.064	5.867.946
2003	485.869	523.947	453.688	362.285	435.744	443.906	425.044	453.346	501.229	475.454	426.893	415.560	5.402.966
2004	486.120	659.506	690.112	518.670	633.289	456.930	416.526	542.042	528.302	476.734	345.959	383.509	6.137.700
2005	529.641	559.000	574.333	568.660	441.251	592.137	338.028	414.808	397.821	449.519	422.928	434.685	5.722.812
2006	513.968	593.830	317.875	333.704	526.469	722.678	783.997	584.960	503.532	414.797	302.672	512.313	6.110.795
2007	414.980	502.614	547.621	527.151	326.617	235.247	528.387	502.988	617.462	387.352	392.098	357.301	5.339.818
2008	472.328	483.469	303.337	394.930	255.430	390.919	455.873	674.675	582.204	518.956	389.391	487.586	5.409.098
2009	406.006	430.207	496.751	558.985	636.150	443.535	456.793	499.348	602.174	440.233	323.551	235.622	5.529.354
2010	268.054	287.595	464.649	209.519	358.391	462.683	434.184	514.460	466.214	303.485	227.916	309.228	4.306.377
2011	555.577	364.850	338.911	310.336	261.803	244.091	237.881	420.746	496.347	456.505	490.628	344.498	4.522.174
2012	208.127	481.159	506.700	297.371	577.813	736.671	726.305	799.625	594.903	455.095	503.958	353.648	6.241.376
2013	500.167	310.477	542.215	[redacted]									1.352.859
	Monthly Average												
Average	421.352	454.752	460.961	409.754	475.692	454.982	493.813	540.218	484.040	408.549	349.842	373.109	443.922
	% of Yearly Average												
Average	95%	102%	104%	92%	107%	102%	111%	122%	109%	92%	79%	84%	

Appendix F Distribution of Favourable Wind Months - Tables

Distribution of favorable wind months — CHBG: 540MW

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	
Jan		FWM		FWM		FWM	FWM	FWM	FWM		FWM		FWM	FWM		FWM			FWM	11	61%
Feb			FWM					FWM	FWM	FWM	FWM	FWM	FWM	FWM					FWM	9	53%
Mar			FWM	FWM				FWM	FWM	FWM			FWM			FWM			FWM	8	47%
Apr			FWM	FWM				FWM	FWM	FWM	FWM		FWM							7	44%
May								FWM	FWM											2	13%
Jun									FWM											1	6%
Jul																				0	0%
Aug									FWM											1	6%
Sep							FWM								FWM					2	11%
Oct								FWM												1	6%
Nov								FWM												1	6%
Dec		FWM		FWM		FWM		FWM							FWM					5	28%
																				48	23%

Distribution of favorable wind months — GTPE: 560MW

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	
Jan				FWM	FWM	FWM		FWM								FWM				5	28%
Feb					FWM	FWM		FWM												3	18%
Mar		FWM		FWM		FWM						FWM								4	24%
Apr		FWM	FWM	FWM		FWM		FWM	FWM			FWM								7	44%
May		FWM	FWM			FWM		FWM	FWM			FWM								6	38%
Jun		FWM	FWM	FWM		FWM	FWM	FWM	FWM	FWM		FWM								9	53%
Jul		FWM	FWM	FWM		FWM	FWM	FWM	FWM	FWM								FWM		9	53%
Aug			FWM			FWM	FWM	FWM	FWM	FWM										6	33%
Sep							FWM													1	6%
Oct																				0	0%
Nov								FWM												1	6%
Dec					FWM		FWM	FWM							FWM					4	22%
																				55	26%

Distribution of favorable wind months — GVIO: 1200MW

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	
Jan		FWM		FWM	FWM	FWM		FWM								FWM				6	33%
Feb					FWM	FWM		FWM											FWM	4	24%
Mar				FWM		FWM			FWM			FWM				FWM				5	29%
Apr			FWM	FWM				FWM	FWM			FWM								5	31%
May									FWM			FWM		FWM						3	19%
Jun			FWM	FWM	FWM	FWM	FWM		FWM				FWM							7	41%
Jul		FWM			FWM	FWM	FWM		FWM	FWM	FWM									7	41%
Aug									FWM											1	6%
Sep							FWM													1	6%
Oct								FWM												1	6%
Nov								FWM												1	6%
Dec				FWM	FWM	FWM	FWM	FWM							FWM					6	33%
																				47	23%

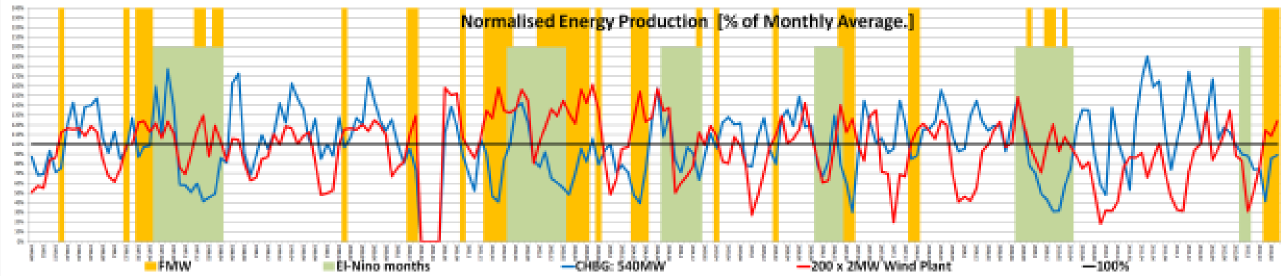
Distribution of favorable wind months — SLVJ: 285MW

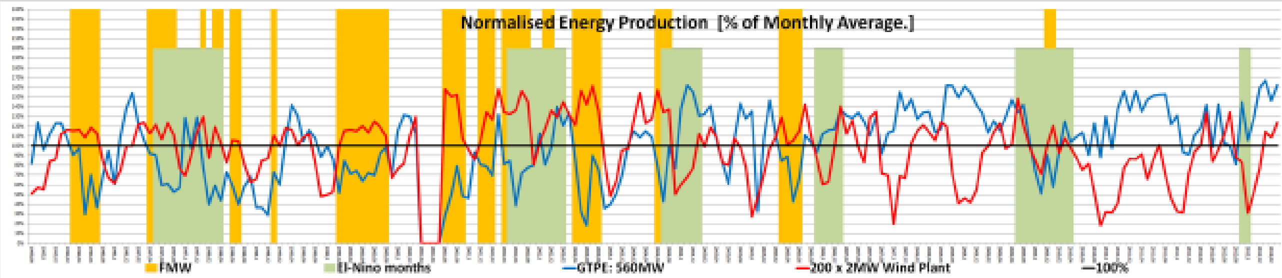
	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	
Jan				FWM			FWM		FWM							FWM			FWM	5	28%
Feb								FWM	FWM				FWM							3	18%
Mar				FWM				FWM	FWM	FWM			FWM			FWM			FWM	7	41%
Apr			FWM	FWM				FWM	FWM	FWM										5	31%
May		FWM	FWM					FWM	FWM	FWM										5	31%
Jun		FWM	FWM	FWM	FWM		FWM	FWM	FWM	FWM		FWM			FWM			FWM		11	65%
Jul				FWM	FWM		FWM	FWM	FWM	FWM	FWM	FWM	FWM		FWM			FWM		11	65%
Aug							FWM	FWM	FWM	FWM	FWM	FWM			FWM					7	39%
Sep							FWM								FWM					2	11%
Oct								FWM												1	6%
Nov								FWM												1	6%
Dec				FWM		FWM	FWM	FWM				FWM			FWM					6	33%
																				64	31%

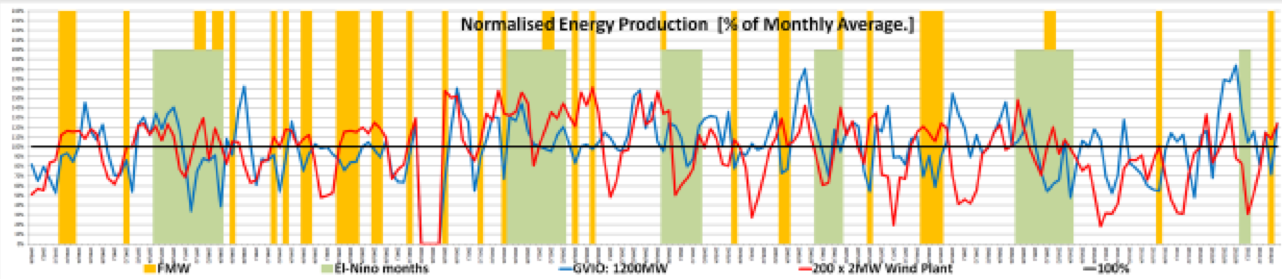
Distribution of favorable wind months — All units: 2585MW

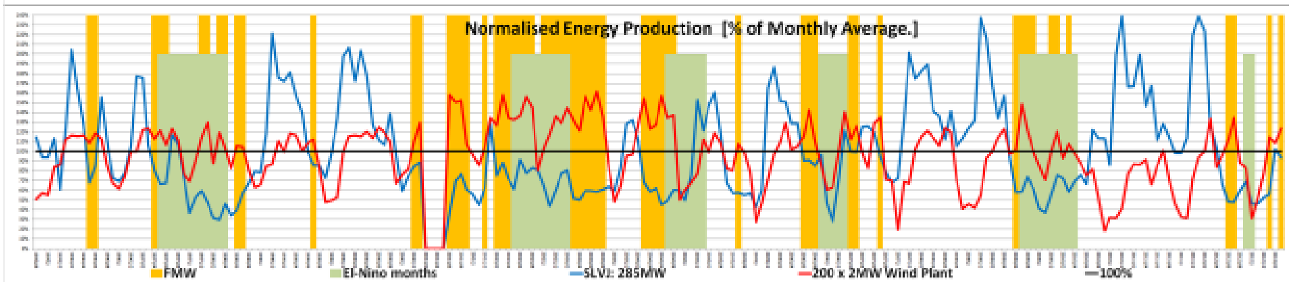
	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total	
Jan		FWM		FWM	FWM	FWM		FWM								FWM				6	33%
Feb					FWM	FWM		FWM											FWM	4	24%
Mar				FWM		FWM			FWM			FWM				FWM				5	29%
Apr			FWM	FWM				FWM	FWM			FWM								5	31%
May									FWM			FWM		FWM						3	19%
Jun			FWM	FWM	FWM	FWM	FWM		FWM				FWM							7	41%
Jul		FWM			FWM	FWM	FWM		FWM	FWM	FWM									7	41%
Aug									FWM											1	6%
Sep							FWM													1	6%
Oct								FWM												1	6%
Nov								FWM												1	6%
Dec				FWM	FWM	FWM	FWM	FWM							FWM					6	33%
																				47	23%

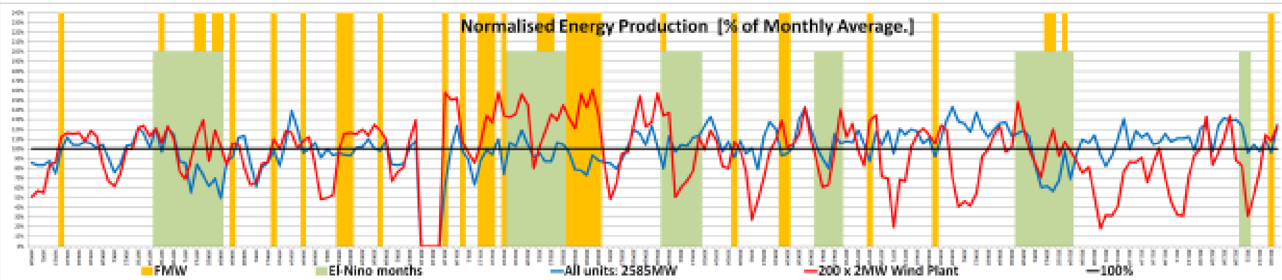
Appendix G Distribution of Favourable Wind Months – Graphs







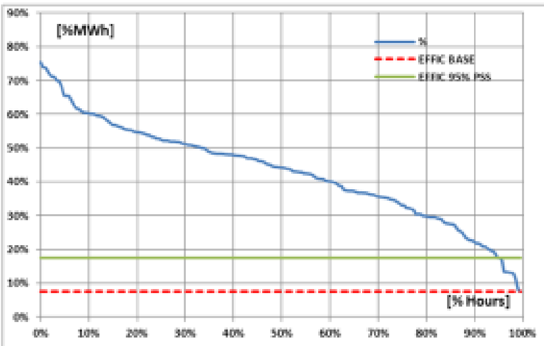




Appendix H 15 x 1,3MW Wind farm - ENFICC

Jepirachi		
Installed Power	19,5	MW
Effective Net Capacity	17,4	MW

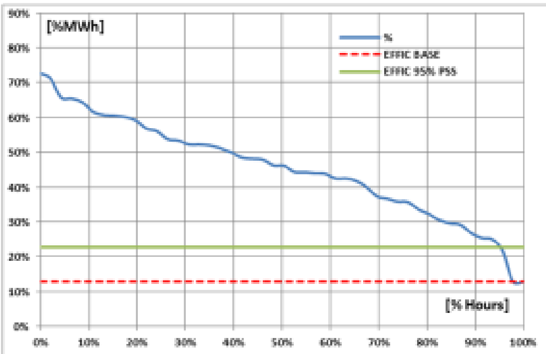
All Months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	7,5%	17,5%	17,4%	17,7%	43,0%
Months	208	10	95,2%	94,7%	

Jepirachi		
Installed Power	19,5	MW
Effective Net Capacity	17,4	MW

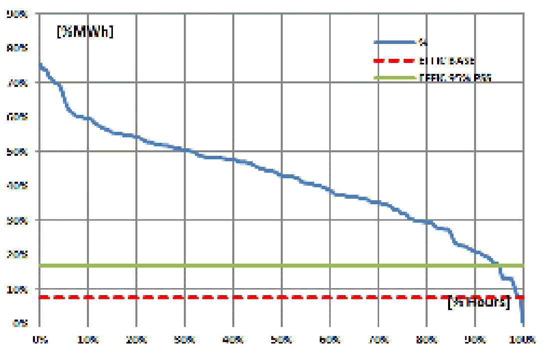
El-Nino months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	12,9%	22,7%	21,8%	25,0%	45,8%
Months	46	2	95,6%	93,4%	

Jepirachi		
Installed Power	20	MW
Effective Net Capacity	17	MW

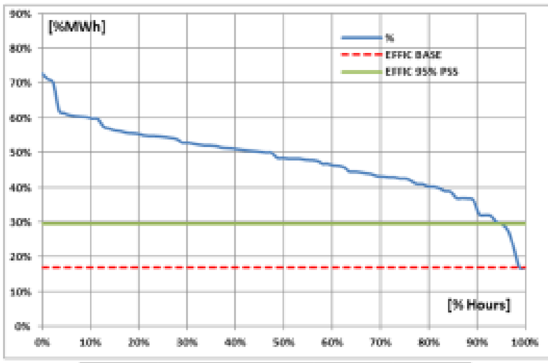
All months excl. El-Nino months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	7,7%	16,9%	16,9%	17,4%	42,2%
Months	208	8	95,0%	94,4%	

Jepirachi		
Installed Power	19,5	MW
Effective Net Capacity	17,4	MW

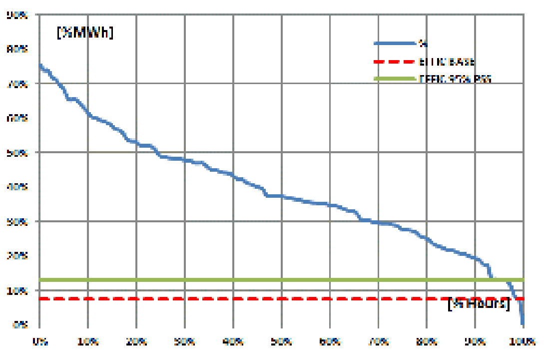
CREG Dry months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	16,9%	29,5%	29,4%	29,9%	47,7%
Months	86	4	95,2%	94,0%	

Jepirachi		
Installed Power	20	MW
Effective Net Capacity	17	MW

All months excl. CREG Dry months

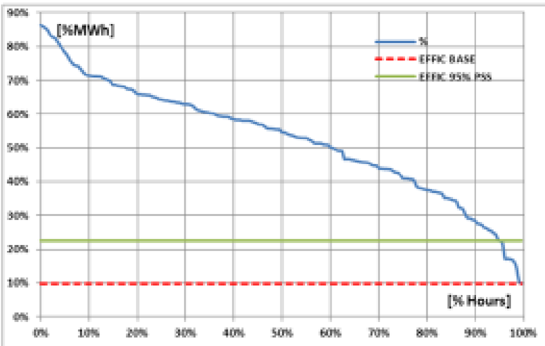


	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	7,7%	11,7%	11,2%	11,1%	39,5%
Months	208	6	95,1%	94,1%	

Appendix I 200 x 2,0MW Wind farm - ENFICC

200x2,0 MW Windfarm		
Installed Power	400,0	MW
Effective Net Capacity	361,5	MW

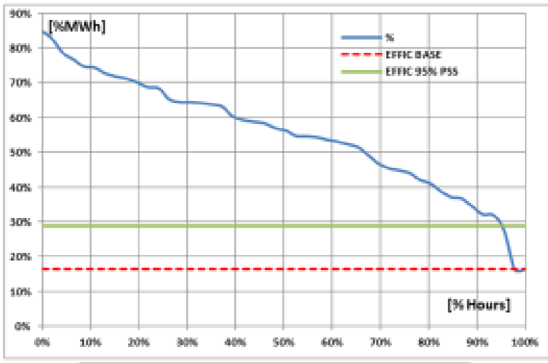
All Months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	9,9%	22,5%	22,3%	22,8%	52,7%
Months	208	10	95,2%	94,7%	

200x2,0 MW Windfarm		
Installed Power	400,0	MW
Effective Net Capacity	361,5	MW

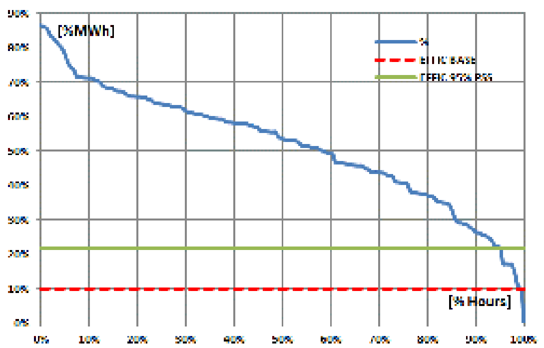
El-Nino months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	16,3%	28,8%	27,5%	31,9%	55,2%
Months	46	2	95,6%	93,4%	

200x2,0 MW Windfarm		
Installed Power	400	MW
Effective Net Capacity	362	MW

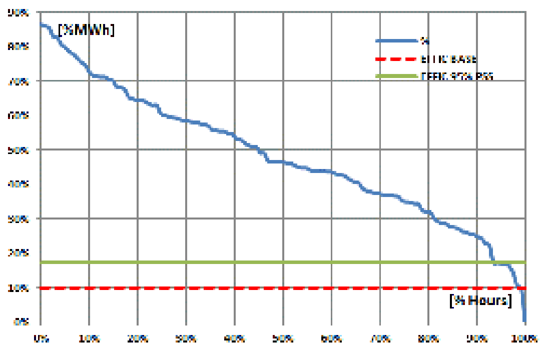
All months excl. El-Nino months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	9,9%	21,8%	21,8%	22,1%	51,8%
Months	208	8	95,0%	94,4%	

200x2,0 MW Windfarm		
Installed Power	400	MW
Effective Net Capacity	362	MW

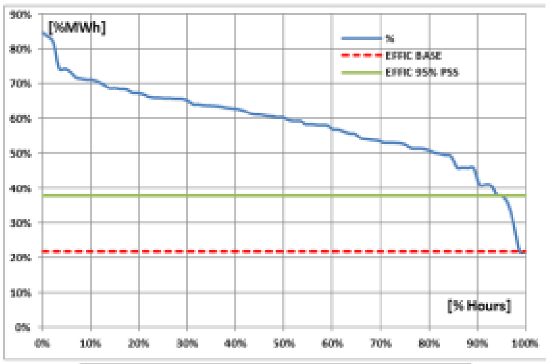
All months excl. CREG Dry months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	9,9%	17,1%	17,1%	17,2%	48,4%
Months	208	6	95,1%	94,2%	

200x2,0 MW Windfarm		
Installed Power	400,0	MW
Effective Net Capacity	361,5	MW

CREG Dry months

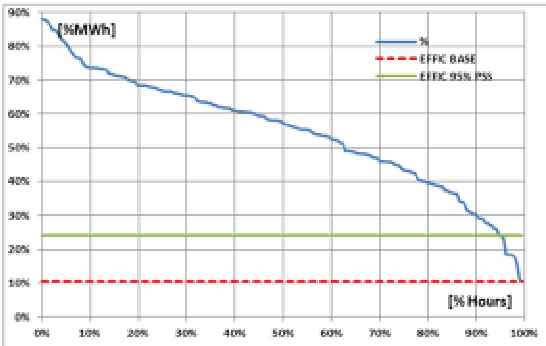


	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	21,8%	37,8%	37,7%	38,1%	58,5%
Months	86	4	95,2%	94,0%	

Appendix J 134 x 3,0 MW Wind farm - ENFICC

134x3,0 MW Windfarm		
Installed Power	402,0	MW
Effective Net Capacity	373,4	MW

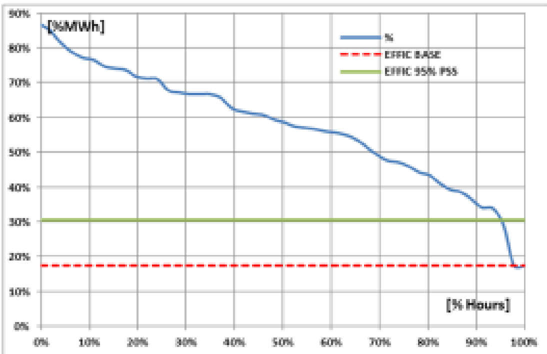
All Months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	10,6%	24,1%	23,9%	24,4%	55,0%
Months	208	10	95,2%	94,7%	

134x3,0 MW Windfarm		
Installed Power	402,0	MW
Effective Net Capacity	373,4	MW

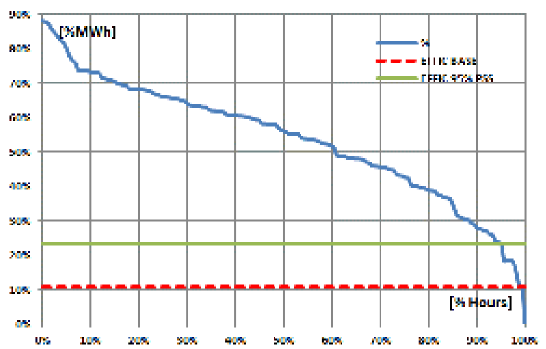
El-Nino months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	17,4%	30,5%	29,1%	33,8%	57,5%
Months	46	2	95,6%	93,4%	

134x3,0 MW Windfarm		
Installed Power	402	MW
Effective Net Capacity	373	MW

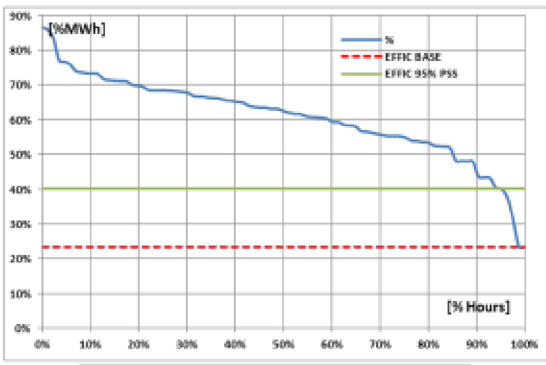
All months excl. El-Nino months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	10,0%	21,4%	21,4%	21,9%	54,1%
Months	208	8	95,0%	94,4%	

134x3,0 MW Windfarm		
Installed Power	402,0	MW
Effective Net Capacity	373,4	MW

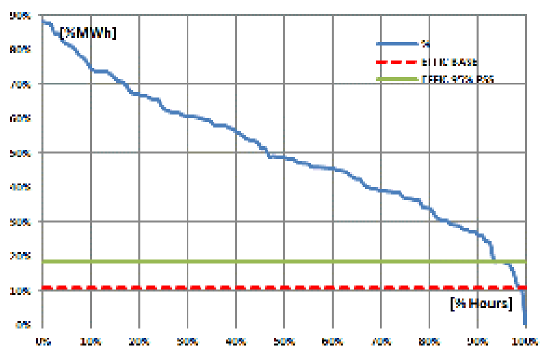
CREG Dry months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	23,4%	40,1%	40,0%	40,4%	61,0%
Months	86	4	95,2%	94,0%	

134x3,0 MW Windfarm		
Installed Power	402	MW
Effective Net Capacity	373	MW

All months excl. CREG Dry months

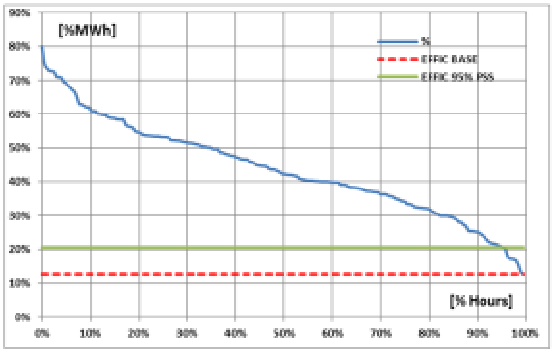


	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	10,0%	18,1%	18,4%	18,4%	50,5%
Months	208	6	95,1%	94,7%	

Appendix K BETANIA GENERADOR 540MW - ENFICC

CHBG: 540MW		
Installed Power	540,0	MW
Effective Net Capacity	540,0	MW

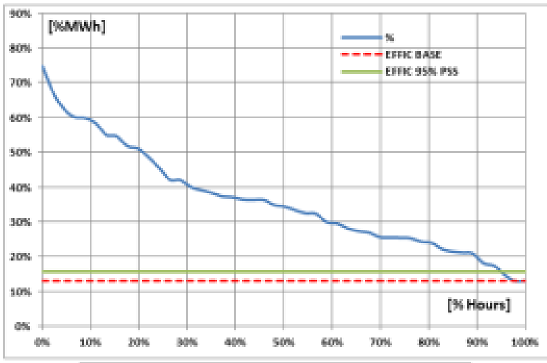
All Months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	12,6%	20,6%	20,4%	20,9%	43,7%
Months	208	10	95,2%	94,7%	

CHBG: 540MW		
Installed Power	540,0	MW
Effective Net Capacity	540,0	MW

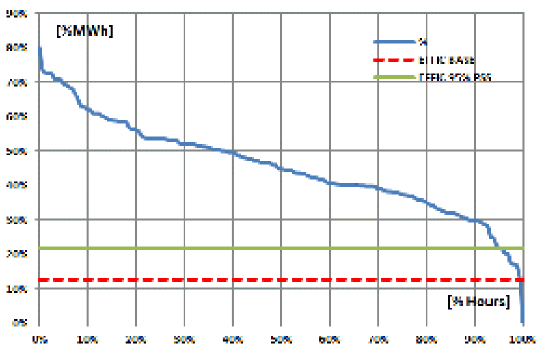
El-Nino months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	13,0%	15,7%	14,7%	17,4%	35,7%
Months	46	2	95,8%	93,6%	

CHBG: 540MW		
Installed Power	540	MW
Effective Net Capacity	540	MW

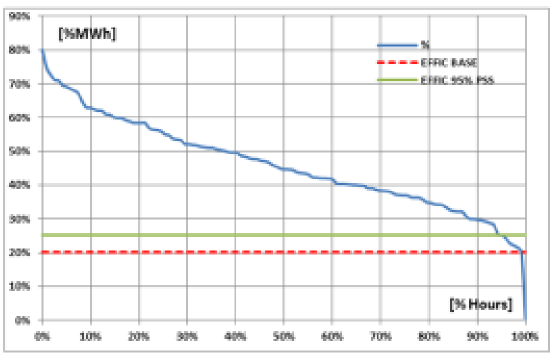
All months excl. El-Nino months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	17,0%	21,9%	21,8%	22,8%	45,2%
Months	208	8	95,1%	94,5%	

CHBG: 540MW		
Installed Power	540,0	MW
Effective Net Capacity	540,0	MW

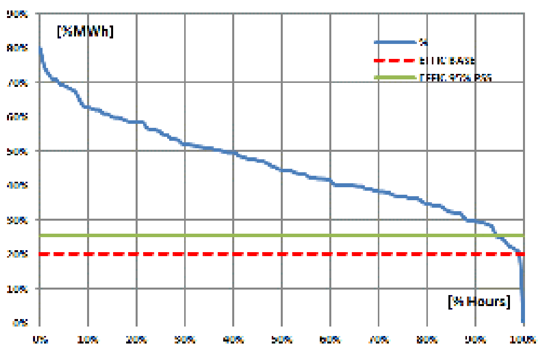
All months ekskl. CREG Dry months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	20,2%	25,2%	25,2%	25,4%	27,1%
Months	208	6	95,1%	94,3%	

CHBG: 540MW		
Installed Power	540	MW
Effective Net Capacity	540	MW

All months excl. CREG Dry months

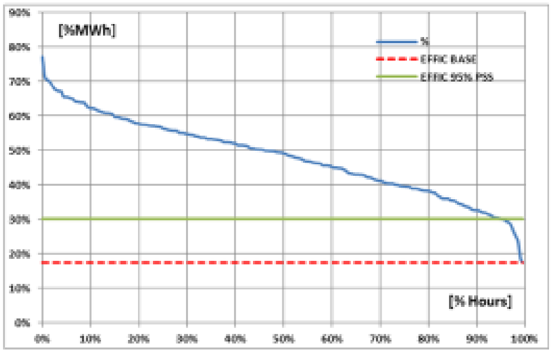


	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	20,2%	25,2%	25,2%	25,4%	46,1%
Months	208	6	95,1%	94,1%	

Appendix L 2 x 540 MW Portfolio - ENFICC

Hydro (CHBG)/Wind : 2x540 MW		
Installed Power	1.138	MW
Effective Net Capacity	1.080	MW

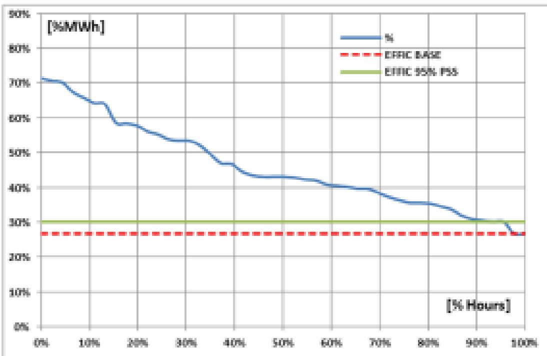
All Months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	17,5%	30,2%	30,1%	30,4%	48,2%
Months	208	10	95,2%	94,7%	

Hydro (CHBG)/Wind : 2x540 MW		
Installed Power	1.138	MW
Effective Net Capacity	1.080	MW

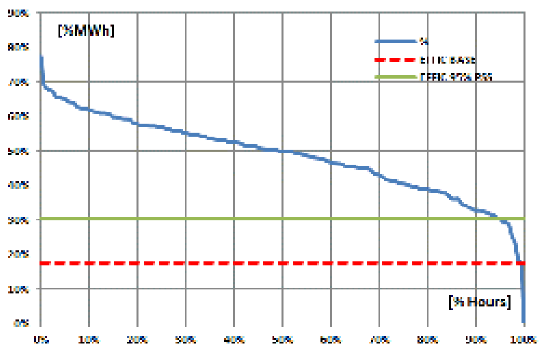
El-Nino months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	26,7%	30,1%	30,1%	30,1%	45,7%
Months	46	2	95,6%	93,4%	

Hydro (CHBG)/Wind : 2x540 MW		
Installed Power	1.138	MW
Effective Net Capacity	1.080	MW

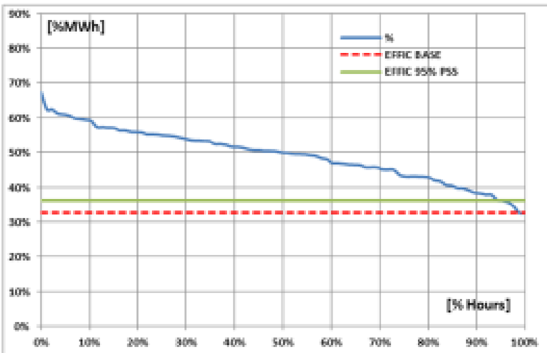
All months excl. El-Nino months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	17,5%	30,4%	30,4%	30,5%	48,8%
Months	208	8	95,0%	94,4%	

Hydro (CHBG)/Wind : 2x540 MW		
Installed Power	1.138	MW
Effective Net Capacity	1.080	MW

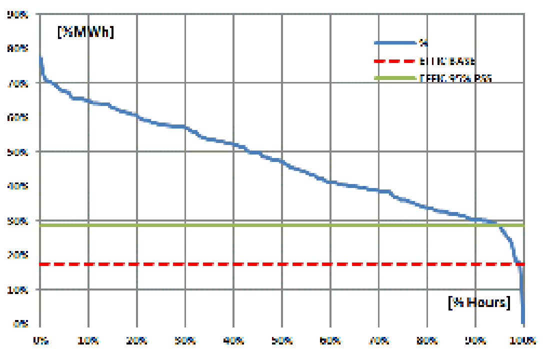
CREG Dry months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	32,7%	36,2%	36,1%	36,3%	49,2%
Months	86	4	95,4%	94,3%	

Hydro (CHBG)/Wind : 2x540 MW		
Installed Power	1.138	MW
Effective Net Capacity	1.080	MW

All months excl. CREG Dry months



	EFFIC BASE	EFFIC 95% PSS	EFFIC >95%	EFFIC <95%	NCF
	17,5%	28,5%	28,5%	28,2%	47,1%
Months	208	6	95,1%	94,2%	