IMPACT ANALYSIS FOR INTEGRATION OF WIND POWER GENERATION IN COLOMBIA

PROJECT REPORT

NOVEMBER 2014

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PROJECT NO. A-038811
DOCUMENT NO. PS-01
VERSION 0
DATE OF ISSUE 29 November 14
PREPARED ANIJ, NA, FLSJ, TEP, KELA
CHECKED MANO
APPROVED KELA

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APPENDICES

List of Abbreviations

AEP	Annual Energy Production
CAPEX	Capital Expenditures
CDM	Clean Development Mechanism
CER	Certified Emission Reduction
CERE	Real equivalent Cost of the Capacity Charge
COP	Colombian Peso
E	East
ENE	East-NorthEast
ENFICC	Energía Firme para el Cargo por Confiabilidad – Firm Energy Factor
EPC	Engineering, Procurement and Construction
EUR	EURO
EWEA	European wind energy association
GWh	Giga Watt hour
IRR	Internal Rate of Return
kV	Kilo Volt
LCoE	Levelized Cost of energy
LEC	Levelized Energy Cost
MCP	Measure Correlate Predict
m/s	meter per second
MW	Mega Watt
NPV	Net Present Value
O&M	Operation and Maintenance
OPEX	Operational Expenditures
PPA	Power Purchase Agreement
US$	United States Dollars
WTG	Wind Turbine Generator
y	Year

Exchange rate: US$/EUR: 1.38

COP/US$: 1,880

1 Introduction

1.1 Background

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.

In order to increase the diversification on the energy mix, and to exploit the potential of renewable resources (such as wind energy) available in the country, it is required to identify the main aspects of their integration in the electricity supply in Colombia.

1.2 Objective

The objective of the assignment is to analyse the integration of wind power generation in Colombia by analysing the following topics:

› Annual energy production (AEP)
 - Wind data analysis
 - AEP estimate

› Modelling of wind power generation technologies

› Electrical studies of 400MW and 100MW Wind farm impact on the power grid in relation to:
 - Normal and faulty operation
 - Transient/dynamic behaviour of the wind farm
 - Harmonic distortion
 - Recommended power grid reinforcements

- Regulatory and Market Analysis
  - Current regulatory frame
  - Wind/Hydro Complementarity
  - Firm Energy Factor
  - El-Niño impact
  - Wind/Hydro portfolio impact
  - Barriers & wind energy integration strategies
  - Review of international experience

1.3 Methodology and preconditions

This present report makes up the project report summarising the complete study. The full study is reported in the following documents:

- 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 objective is reached by an inception mission to Colombia in April 2013 focusing on fact finding and collection of data and electrical system models for the existing power grid in Colombia.

Preliminary review and clarification questions were submitted to UMPE/IDB in May 2013.

UMPE provided wind data series from existing meteorological measurements mast for the Northern site and suitable models of power grid in the Neplan software in June – August 2013. Reliable wind data from the southern site at Santander have not been established consequently the annual energy production and the financial feasibility studies have been limited to the Northern site in the La Guajira area.

Desk studies, analysing and draft reporting for the various topics was implemented in July – November 2013.

Review and final revision of the study reports was completed by February 2013.

The findings and recommendations made by the Consultant were presented during a presentation and NEPLAN workshop held in Colombia during 17th – 21st March 2014.

Study report 02 & 03 were updated in April-May to consider the comments addressed by UMPE and IDB during the presentation in March 2014.

Final revision of the Study Report 02 & 03 and this project report was issued in October 2014 based on the comments received.

2 Conclusions and Recommendations

2.1 Power System Impact

The impact on the power grid by introducing wind farm generation in three steps (100MW in 2013, 500MW in 2019, 1000 MW in 2025) has been investigated. Grid reinforcements imposed by the new wind farms in addition to the already anticipated in the prevailing grid reinforcement plan 2012-2025 are suggested for each scenario.

The power system study verifies that harmonic and transient impact from even the large wind farms not will cause grid instability or inacceptable voltage quality when the largest grid connected unit is kept below 200 MW (as per today).

It is established that wind farms with modern wind turbine design (Type 3 & Type 4) will support the power grid during fault conditions and not as the existing presently in operation at the Jepirachi windfarm (Type 1) cause difficulties for grid stability.

It is observed that no Grid Code is established for connection of large wind farms is in place for the Colombian power grid. Consequently, Consultant has established his own assumptions and general recommendations for such a future grid code as a basis for the power system analysis

2.2 Wind Resource and Financial Viability

Based on the analyses carried out for the site in the La Guajira area, it is found that with a mean wind speed of 8.2 m/s at 50 m above ground and estimated mean wind speed at 78 m hub height of 9.4 m/s and at 84 m hub height of 9.6 m/s, the area can be characterised as a medium-to-high wind area. Based on this it is concluded that from a wind resource point of view the area is suitable for further development of wind power projects.

For development of specific projects it is strongly recommended that a met mast of 60-80m is installed at the given site, and that data is measured for a period of no less than 12 months. This will provide a sound basis on which a wind study of bankable quality can be elaborated.

The financial analyses performed on the two wind farm scenarios (200 x2MW and 134 x 3MW units), based on information gathered from Colombian developers show that the project in the base case is considered financially viable. This applies to both wind type scenarios and to all cases investigated; pure investment (i.e. no financing included), base case market financing and alternative case market financing.

Sensitivity analyses show that the projects are very sensitive to changes in the tariff and in the investment cost. A change in the ENFICC also affects the financial viability, but to a lesser extent than the other two parameters.

Levelized cost of energy for the project has also been estimated. In order to reach the expectation of 10% IRR, the required tariff for the different cases would be:

Case	USD/per MWh - 2MW	USD/per MWh – 3 MW
Pure investment	92.29	88.06
Base case market financing	77.75	74.33
Alternative market financing	76.53	73.18

This shows that the tariff 89.7 USD per MWh (from the current average of the spot market price in 2013) is sufficient, in order to reach an IRR of 10%.

It is recommended to investigate the financial viability further in relation to a specific project for which specific wind data is available. This would provide a more firm basis for drawing firm conclusions.

2.3 Market & Regulatory Aspects

The Colombian electricity market

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

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

Three months (Jan/Feb/Mar) in general have normalised wind speed above its yearly average and normalised hydro inflow below the yearly average. (Apr having a high number of months being favourable wind months could also in general be considered as a favourable wind month as discussed later).

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

The complementarity reconfirmed could justify a changed methodology for the ENFICC.

Analysis of firm energy factor, ENFICC

CREG's present approach for determining the firm energy factor for wind energy does not consider the complementarity between the hydro and wind energy production. The findings in 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 ≈ +5% of the $ENFICC_{95\%}$

› that an increased $ENFICC_{95\%}$ (≈ +7%) could be justified based on the relatively higher wind energy production during the El-Niño months

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

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 wind power development in Colombia could possibly be boosted if either a premium feed-in tariff of 10-20 % of the sales price or an investment grant of 10-20 % of the investment is being introduced. 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.

3 Power System Infrastructure Study

3.1 Objective

The objective of the power system study is to analyse the integration of wind power generation in Colombia and its impact on the power grid. The study comprises:

- Electrical modelling of wind turbines

- Electrical studies of two wind power projects connected to the Colombian power system.

The analysis has been performed on different schemes, such as the power system structure: large-scale projects connected to the transmission network.

- Guajira region
  100 MW wind farm connected to power grid in year 2013
  400 MW wind farm connected to power grid in year 2019
  800 MW wind farm connected to power grid in year 2025

- Norte de Santander region
  100 MW wind farm connected to power grid in year 2019
  200 MW wind farm connected to power grid in year 2025

3.2 Wind turbine types

Wind turbines are electrically generally divided into two main technological categories being defined in IEC 61400 International standards series for wind turbines:

- <u>Constant speed wind turbines, (Type 1 and 2)</u>
  The constant speed wind turbines were installed used in 70s, 80s and 90s, and are built with squirrel cage (asynchronous) induction generators directly connected to the grid a simple, cheap and robust design. They have some disadvantage on supporting the grid and especially when the LVRT

(low voltage right through) criteria are required and when reactive demands are imposed to the wind turbines. The blade control is often stall regulated wings. The LVRT criteria defines that the wind farm/turbines shall be able to stay connected to the grid during a voltage drop to 0% of the nominal voltage during at fault, of a typical duration 100-500 ms and within few seconds to resume to the pre fault power production.

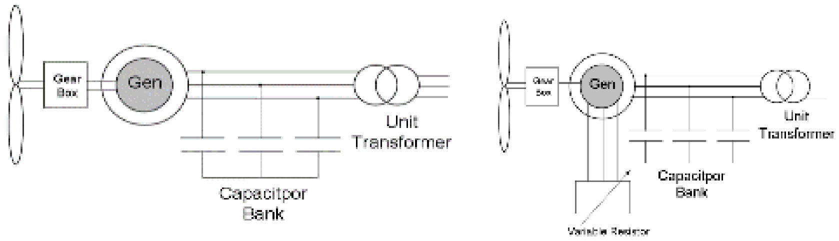


Figure 1 Principle diagrams of the type 1 induction generator and type 2 Variable Rotor resistance Induction generator wind turbine generator

- <u>Variable speed turbines, (Type 3 and 4)</u>
  The variable speed wind turbines are based on converters that began to be economical mid 90s and supported by the development of the modern computer for regulation of the power control. The wind turbines have a rotor speed that varies significant according to the prevailing wind conditions. The aerodynamic control of variable speed machines is based on blade pitch control. Two types of variable speed wind turbines are available on the marked today:

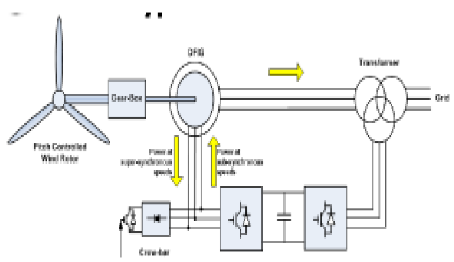


Figure 2a Principle diagram of the type 3 DFIG Double Fed Induction generator

<u>DFIG wind turbine generator (Type 3)</u> utilizing a Doubly-Fed Induction Generator (DFIG) and a rotor converter cascade of reduced rating.
This wind turbine type was introduced in approximately 1995, when the converters were much more expensive than today. The design aimed at satisfying the more demanding power grid requirement on the wind turbines that were introduced by the transmission system operators.

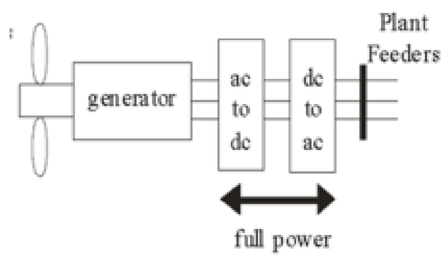


Figure 3b Principle diagrams of the type 4 Full Scale converter generator wind turbine

The full scale power converter (Type 4) utilizing a synchronous or induction generator effectively separated from the grid via a full-power converter. This type is especially useful when connected to a weak power grid or when the wind turbine size is above 2.3 MW and uses gearbox.

3.3 Grid Code Assumptions/Recommendations

When wind turbines are installed in large scale a grid code defining specific requirements on the wind turbines is recommended to secure an optimal operation of the power grid and to minimize the overall system costs.

The grid code should as a minimum regulate the following operational aspects:

› Terminology and definitions

› Voltage and frequency operating range

› Electricity quality

› Reactive power control and voltage regulation

› Active power and frequency control

› Fault ride through requirements, LVRT

› Requirements for reactive current supply during voltage dips

› Protection

› Data communication and exchange of signals

› Verification and documentation

The basic assumptions made in the study is that the wind turbines can produce at a power factor 1 and that the wind farm will stay connected to the grid during grid failures (LVRT criteria).

3.3.1 The connection of the wind farm at the PCC point

The PCC point is defined on the HV side of the wind farm substation transformer. Determining the PCC is important and must be clearly defined prior to the design and planning of any wind farm development. The PCC constitutes the reference point for the grid code requirements for the wind farm.

The PCC point could also be at the metering point on the busbar where the wind farm is connected.

When specifying demands to wind turbines additional definitions as the POC at the wind turbine might make it easier to put requirements to the wind turbines. In some cases a requirements on the MV busbar of the wind farm is most suitable. Requirement in the PCC might introduce not required capacitor banks and shunt reactors (See *Figure 4*)

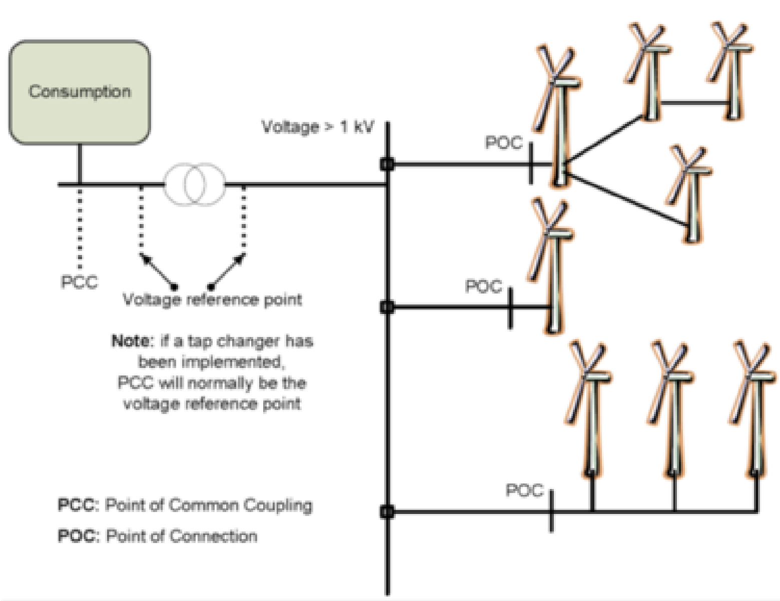


Figure 4 Connection point PCC and POC for wind farms

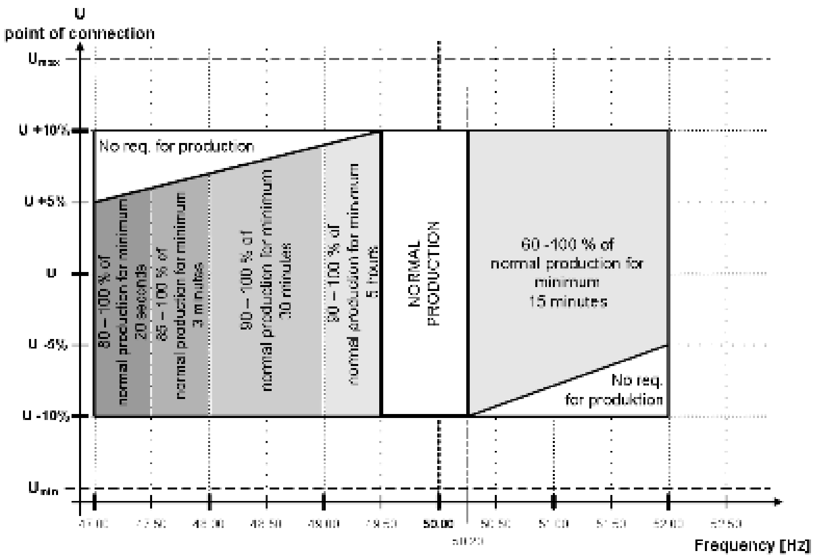


Figure 5 Definition of voltage and frequency

The overall requirements for anticipated active power production, which a wind power plant must comply in case of frequency and voltage deviations, can be illustrated as the *Figure 5*. At over frequency a ramp down of the power production can be introduced. When a transformer is used between the wind turbines and grid

PCC a tap changer often adjusts the voltage level on the MV/wind turbine side and larger voltage variations might be possible.

3.3.2 Reactive power control and voltage regulation

The wind turbines/farm shall be able to be operated in:

- *Q control*
- *Power factor control*
- *Voltage control*

The different modes secure that different problems can be solved by the wind turbines without adding additional components. The operation modes Q and PF control is shown in Figure 6

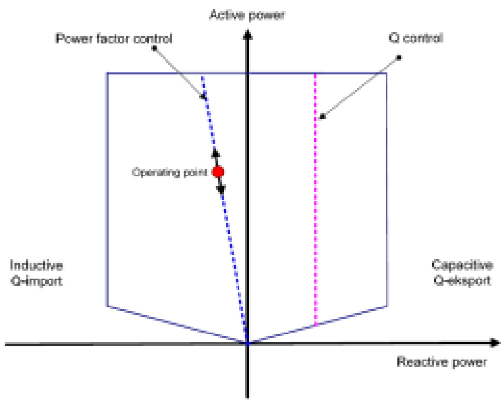


Figure 6 Reactive power output from a wind farm

3.3.3 Active power and frequency control

In order to avoid that the system need to be designed for some marginal cases, the wind farm must be equipped with active power control functions capable of controlling the active power supplied by a wind power plant in the point of connection using orders containing set points and gradients. The principle of the functions are shown in Figure 7 and shall be

- Absolute production constraint
- Delta production constraint (spinning reserve)
- Power gradient constraint

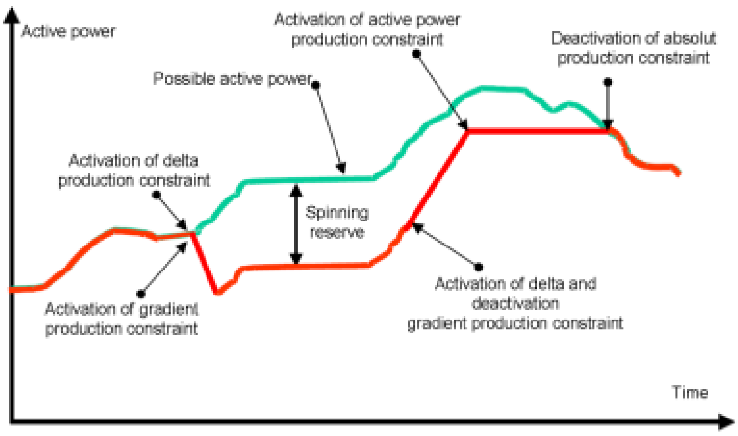


Figure 7 Definition of power control action

3.3.4 Requirements for LVRT during voltage dips

In order to rely on wind farms as a system component it shall stay connected when a failure occurs in the power grid. The wind turbines shall be designed to withstand voltage drops, as shown in Figure 8 also called the LVRT capability.

- Area A is normal operation area.
- Area B is the voltage dip for the wind turbines where the wind turbines shall maintain reactive power support.
- Area C is the area where the wind turbine is allowed to disconnect.

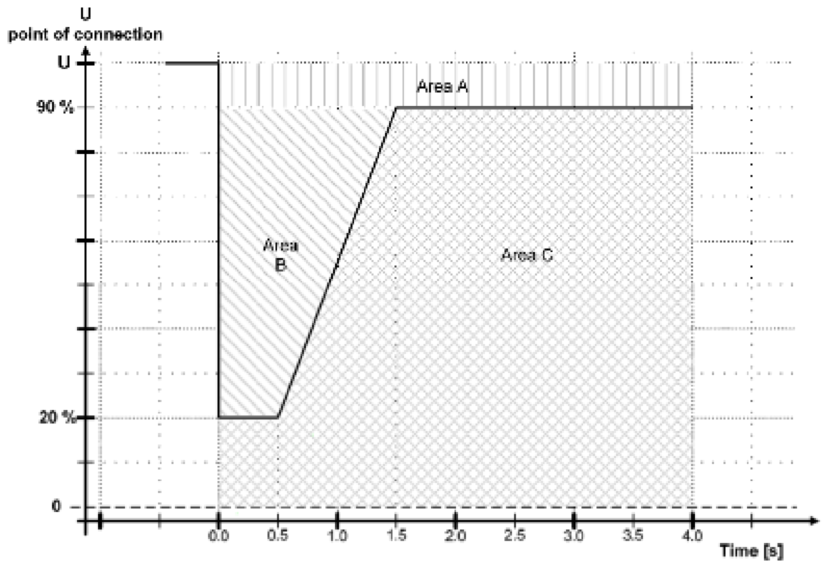


Figure 8 LVRT definition

3.4 Wind Farms Investigated

The wind farms investigated are assumed to be located in the La Guajia region and in Norte de Santander region. The Guajira region has a large potential for wind but have some limitation and insufficiency in the power grid infrastructure today.

The assumed location of the large-scale wind farm can be connected to the transmission network at 220 kV in the Guajira region as shown in Figure 9.

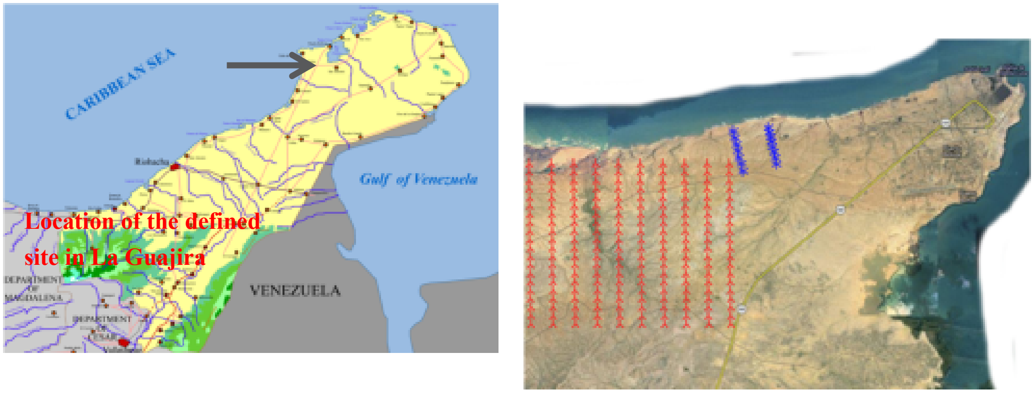


Figure 9 Wind farm in Guajira

The Medium-sized projects in the Norte de Santander area, can be connected to the 115 kV substation level in the OCAÑA substation as indicated below.

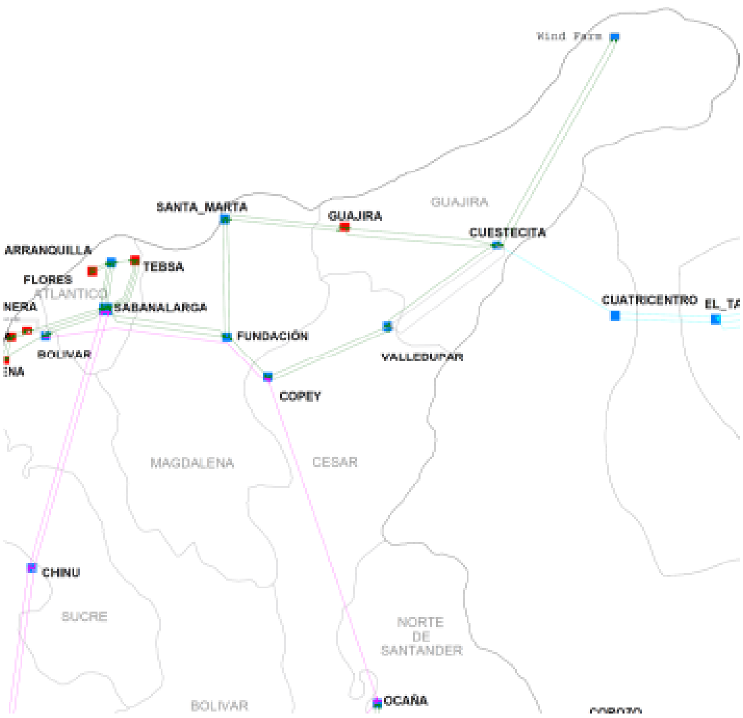


Figure 10 Connections of wind farms

3.5 Power system analysis findings

3.5.1 Recommended Grid Reinforcement Plan

- Wind farm Scenario, year 2013, see Figure 11
  The steady state analysis for year 2013 do not reveal reinforcement need of the network except for the grid connection of the wind farm to the Cuestecita busbar. The Grid connection of wind farms comprises of
  - A new substation at wind farm
  - A new 150 km 230 kV overhead line (Single system)) to the existing Cuestercita substation
  - One new 230 kV line bay in Cuestercita

- Power Grid Reinforcement: None

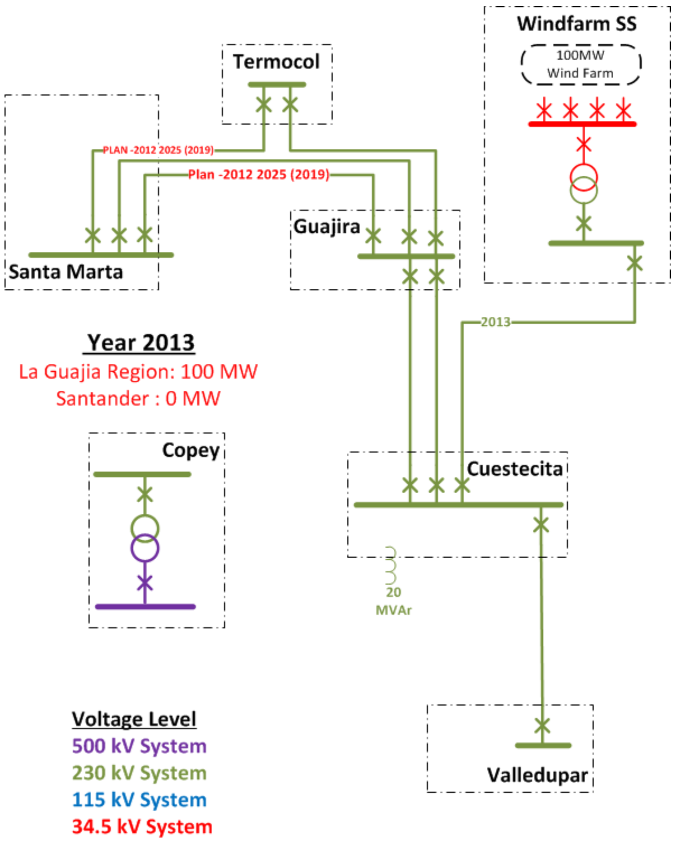


Figure 11 Wind farm scenario 2013

- Wind farm Scenario, year 2019
  - The steady state analysis for year 2019 Grid connection of Wind farms
    - Extension of wind farm substation
    - 230 kV overhead line to Cuestercita upgraded double system
    - One new 230 kV line bay in Cuestercita

- Five 34.5 kV overhead lines and switchgear in Ocaña substation

- Power Grid Reinforcement
  The steady state analysis 2019 identifies the following grid reinforcement
  - two additional 116 km 230 kV power lines from Valledupar SS to Cuestecita SS
  - one additional 39 MVAr reactor and 39 MVAr capacitor shall be installed in Cuestecita SS when 400 MW wind farm generation is connected to the Cuestecita SS
  - the general need for reactive power in the area could justify an SVC in the COPEY SS 500kV station and a second 500/230 kV transformer is required.
  - A 230 kV second circuit Guajira-Santa Marta is required, and with additional MVAr support in Santa Marta SS. Thus a 60 MVAr capacitor bank is suggested in Santa Marta SS. Alternatively the reactive power to Santa Marta SS could be secured by a new parallel 230 kV circuit between Santa-Marta SS and Termocol SS.

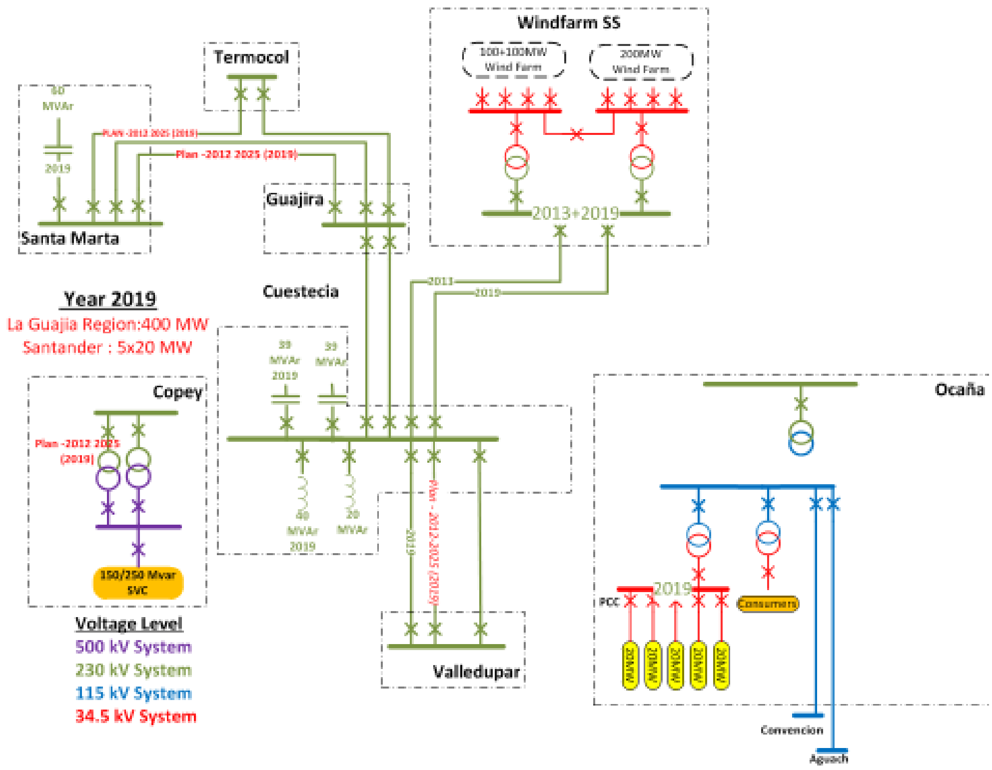


Figure 12 Wind farm scenario 2019

- Wind farm Scenario, 2025Grid connection of Wind farms
  Connecting 400+400 MW to the Cuestecita SS will demand
  - one additional 39 MVAr reactor and 58 MVAr capacitor in Cuestecita SS.

- 150 km new 230 kV double system overhead lined to Cuestercita

- Power Grid Reinforcement
  - A new 92 km 230 kV power line (one circuit) between Guajira SS and Santa Marta SS is required.
  - One additional 230/115 kV 90 MVA transformer is needed in Ocaña SS when 200 MW wind is connected

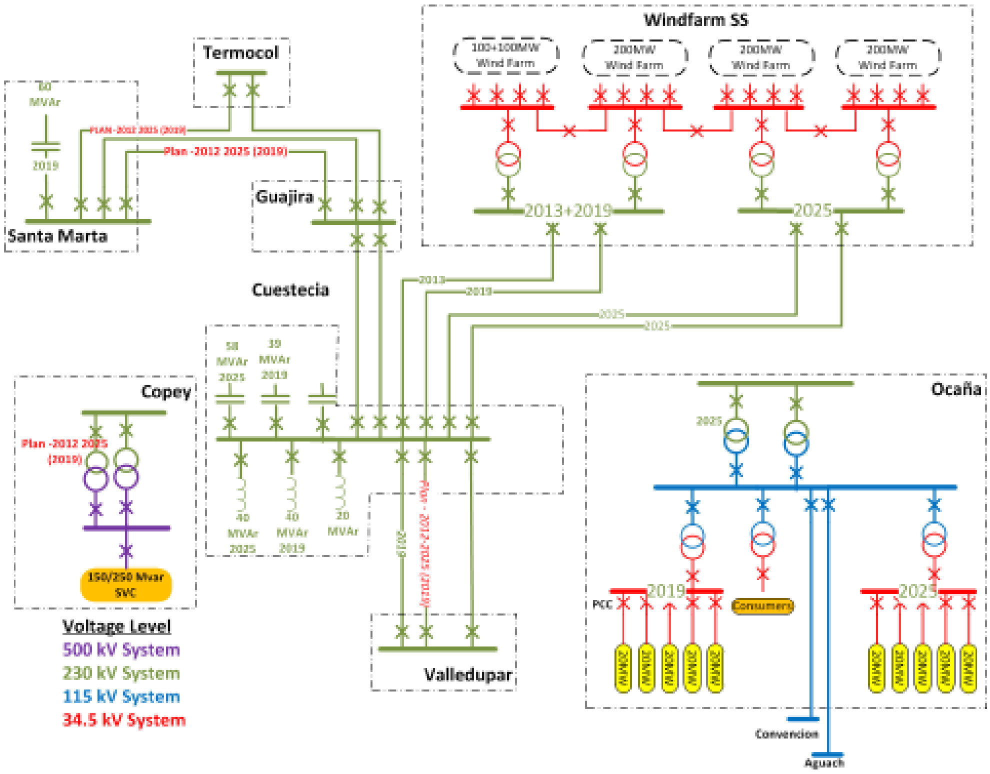


Figure 13 Wind farm scenario 2025

3.5.2 Grid Connection and Reinforcement Costs

The power system for a wind farm and adjacent grid consists of

- Wind turbines
- Inter turbine grid (10…72 kV)
- Wind farm substation
- Interconnection to power grid
- Reinforcement of power grid

The figure below illustrates the concept for grid connection of the 400 MW wind farm in in the La Guajia region being connected to the Cuestecita SS

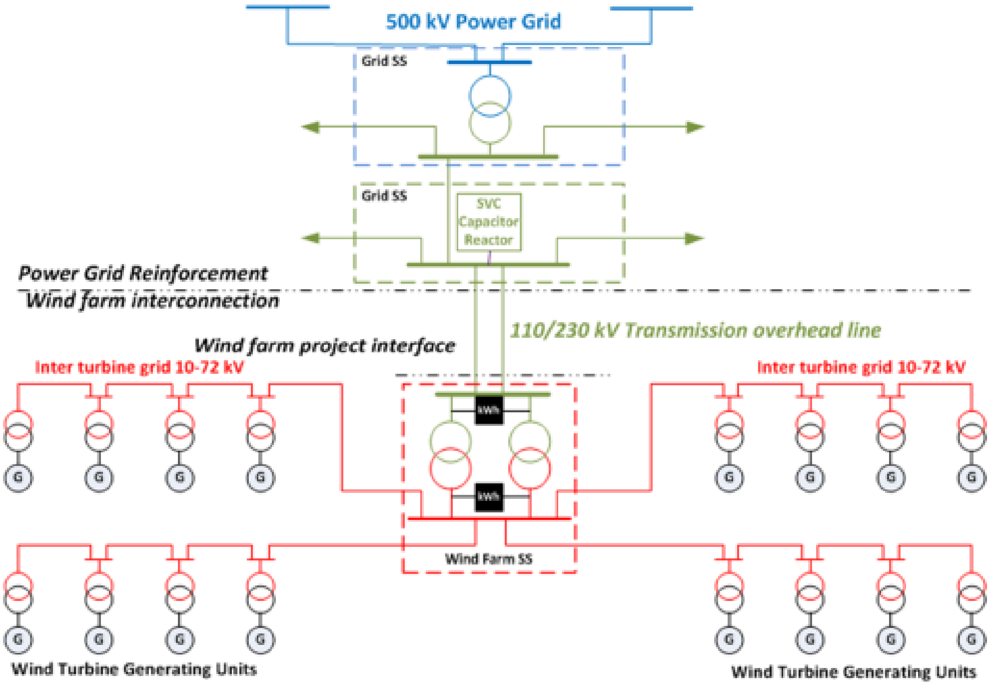


Figure 14 Principles of wind farm grid connection

The smaller wind farms connected to Ocaña SS will only have the cost to connect to the 34,5 kV grid, and to some extent the 34,5/110 kV transformer, while the transmission system operator shall be responsible for the upgrade of the power grid and the substation.

The larger wind farms in the Guajira region have the costs for the new wind farm substation and transmission lines to the Cuestecita substation. Costs of all additional equipment in Cuestecita and the grid are covered by the transmission system operator.

The table below summarises the cost budget for the wind farm grid interconnection components (paid by the wind farm developer and the power grid reinforcements components paid by the TSO).

Power Grid Cost Estimate		Unit Price [tUSD]	2013 [QTY]	2013 [MUSD]	2019 [QTY]	2019 [MUSD]	2025 [QTY]	2025 [MUSD]
Honda substation				**6,0**		**6,1**		**11,9**
230/34.5kV- 250 MVA Transformer	w	3.200	1	3,2	1	3,2	2	6,4
230 kV bays	w	1.037	1	1,0	1	1,0	2	2,1
34.5 kV bays	w	73	7	0,5	8	0,6	13	0,9
Substation Building	w	1.250	1	1,3	1	1,3	2	2,5
Cuestecita substation				**1,0**		**6,7**		**5,9**
230 kV bays	w	1.037	1	1,0	5	5,2	4	4,1
Capacitor Bank, 39MVar	gw	384			1	0,4		
Capacitor Bank, 58MVar	gw	560					1	0,6
Reactor Bank, 40 Mvar	gw	1.167			1	1,2	1	1,2
Ocaña substation						**3,1**		**7,0**
220/115kV- 90 MVA Transformer	gw	2.156					1	2,2
115/34.5kV- 125 MVA Transformer	w	1.960			1	2,0	1	2,0
230 kV bays	gw	1.037					1	1,0
115 kV bays	w	741			1	0,7	2	1,5
34.5 kV bays	w	73			5	0,4	5	0,4
Copey substation						**16,1**		
150/250 Mvar SVC	gp	9.600			1	9,6		
Transformer Copey	gp	5.500			1	5,5		
230 kV bays	gp	1.037			1	1,0		
Guajira substation						**1,0**		
230 kV bays	gp	1.037			1	1,0		
Santa Marta substation						**3,8**		
230 kV bays	gp	1.037			3	3,1		
Capacitor Bank, 60MVar	gw	660			1	0,7		
Termocol substation						**1,0**		
230 kV bays	gp	1.037			1	1,0		
230 kV Overhead Lines				**64,4**		**117,9**		**75,2**
Cuestecita S/S to Honda S/S single line	w	429	150	64,4				
Cuestecita S/S to Valledupar S/S	gw	250,5			116	29,1		
Cuestecita S/S to Valledupar S/S	gp	250,5			116	29,1		
Cuestecita S/S to Honda S/S additional line	w	107			150	16,1		
Cuestecita S/S to Honda S/S double line	w	501					150	75,2
Guajira S/S to Santa Marta	gp	429			91	39,0		
Termocol SS to Santa Marta	gp	429			11	4,7		
				71,4		**155,8**		**99,9**

		2013	2019	2025
Wind farm Grid Connection	***w***	***71,4***	***30,4***	***95,0***
Reinforcement of Power Grid : 2012-2025 plan	***gp***	***0,0***	***94,1***	***0,0***
Reinforcement of Power Grid imposed by Wind Farms	***gw***	***0,0***	***31,3***	***4,9***

Table 1 Cost estimate on grid connection wind

The individual costs are divided so new adjustments on the cost can be made when UPME decides the exact spilt of cost for these wind projects

- Wind farm scenario, year 2013
  The 100 MW wind farm in the Guajira region will in 2013 only have grid connection costs for the connection in Cuestecita . (Ref. Figure 11)

- Wind Farm Scenario, year 2019
  The additional 300 MW in Guajira (+100 MW in 2013) + 5x20 MW in Ocaña will have the transmission related costs as shown in *Table 1*. The 400 MW wind in Guajira will also result in an additional double circuit transmission line between Cuestecita and Valledupar. In the Plan de Expansión de Referencia Generación – Transmisión 2012-2025 a single circuit was assumed already, so the additional costs on upgrading the

transmission line from single system to double system is related to the wind integration.

The lack of reactive power support in the north observed in the Plan de Expansión de Referencia Generación – Transmisión 2012-2025 have been addressed. This study suggest the Copey station as a suitable place for the expansion with a SVC.

From 2019 to 2025 the wind 400MW+100MW is doubled to a total of 1000 MW + Jepirachi wind farm. Since the load also increases in the area the most of the grid is sufficient.

3.5.3 400 MW Wind farm - La Guajia Region

The steady state load flow has been carried out for 2013 with 100 MW wind, for 2019 with 400 MW wind and for 2025 with 800 MW wind. The study carried out for the three years are similar, but in this summary the 400 MW in 2019 is discussed in detail.

3.5.3.1 Steady state load flow

In the case 2019 a 400 MW wind farm is added (2x200 MW) in Guajira connected through two 230 kV 150 km overhead lines to the 230 kV Cuestecita station. (See Figure 10). Two load demand cases (high demand and low demand) and combined with two base generation pattern as the cases hydro (high/low demand) and thermal generation pattern (only for the high demand) are investigated. The *Table 2* shows the different studied scenarios with the distributed amount of generation based on hydro/Coal/Gas/Wind and others.

Study 2019 /MW generation	High demand		Low demand
Type:	Hydro	Thermal	Hydro
Hidráulico	10088.6	9735.0	6942.8
Carbón	523.3	523.3	0.0
Gas	2784.1	3002.6	414.2
Eolica	518.0	518.0	518.0
Other	139.9	139.9	139.9
Total	14054.0	13918.7	8014.9

Table 2 Generation scenarios Colombia 2019.

In the contingency analysis the N-1 criterion is not fulfilled between the wind farm substation and the existing grid interconnection point in Cuestecita (even though a certain overload capacity is available), since the 230 kV transmission lines are considered as generator lines. The study does also take into consideration that the maximum generating element in the grid is 270 MW, since each transmission line carries a maximum of 200 MW.

In order to adapt the increased amount of wind (the 100 MW at Ocaña and the 400 MW at Cuestecita) the production from some generators has been decreased. The changes in production pattern MW chosen is show in *Table 3*.

GENERACIÓN ELECTRICA Changes is production		2019 NEPLAN					
		Large demand				Low demand	
		Base	Wind	Base	Wind	Base	Wind
CENTRAL	COMBUSTIBLE	Hydro	Hydro	Thermal	Thermal	Hydro	Hydro
SAN CARLOS GENERADOR	H	108	374	163	130	447	111
GUAVIO GENERADOR	H	1085	868	1067	853	808	646
CHIVOR GENERADOR	H	888	666	880	660	0	0
TERMO SIERRA	G	269	163	269	269	0	0
TERMOFLORES GENERA.	G	132	20	132	132	0	0
MENOR JEPIRACHI	EOLICA	11	18	11	18	11	18
Wind farm HONDA	EOLICA	0	400	0	400	0	400
Wind farm OCAÑA	EOLICA	0	100	0	100	0	100
Total		13939	14054	13878	13919	8006	8015

Table 3 Generation changes scenarios Colombia 2019

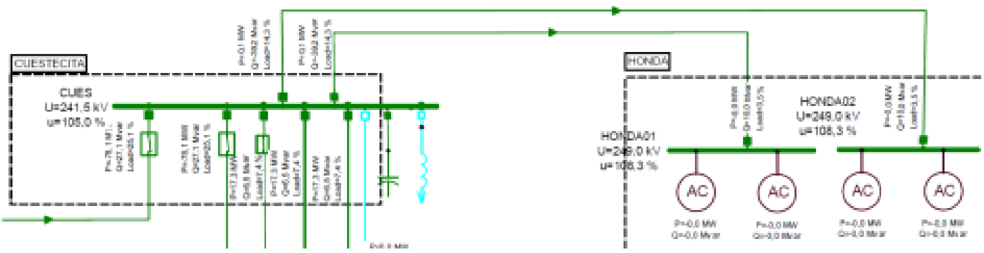


Figure 15 2019 Cuestecita maximum load, hydro generation no wind

The connecting lines to the wind farm increase the additional reactive power generation with 70 MVAr during no load conditions. Consequently, an additional reactor 39 MVAR at the Cuestecita substation is needed to control the voltage in the area.

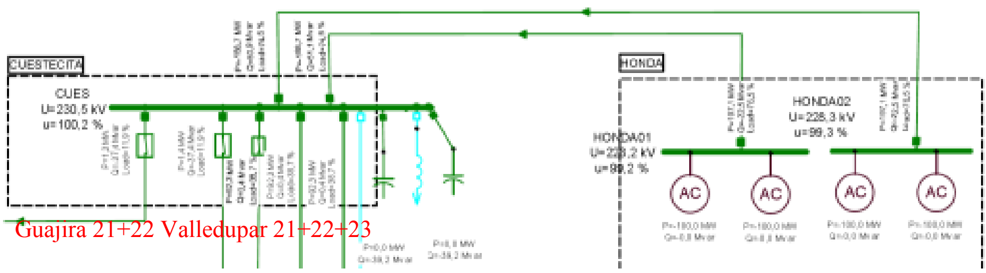


Figure 16 2019 Cuestecita maximum load, hydro generation wind

Two additional power lines between Cuestecita and Valledupar (22+23) are necessary at full wind production to evacuate the power at high load to fulfil the N-1 criterion on these lines. When the wind farm is at full production the transmission lines consumes reactive power and demand an installation of one additional capacitor bank sized 39 MVAr in Cuestecita.

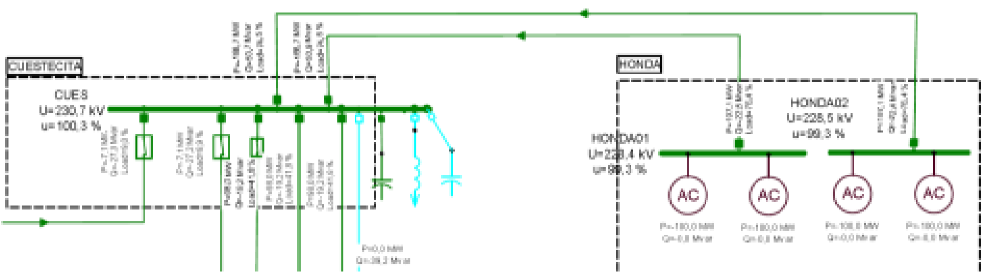


Figure 17 2019 Cuestecita maximum load, thermal generation, wind

The thermal generation case as well indicates that two overhead lines from Cuestecita to Valledupar are needed.

The detailed report the 2013 load flows study includes the four cases with hydro and thermal generation both with high and low load and for 2025 for one case with hydro generation and high load.

3.5.3.2 Contingency analysis

The contingency analysis is based on the effects of outages on lines/elements, which are most influenced by the major wind farm in Guajira. The contingency analysis identifies line/elements that are violated primarily in the Guajira-CESAR-Magdalena area and Bolivar area. The concern in the analysis is the voltage and the load at 230 and 500 kV voltage level.

The contingencies (line elements to be taken out) in the system are identified and listed in Table 4. Also parallel elements, that will take over part of the load when the contingency analysis is carried out are shown.

Element number	Element name	Element type	Parallel line/element
2095	CUES_GUAJ_21	230 kV line	CUES_GUAJ_22
2101	SMAR_GUAJ_21	230 kV line	SMAR_GUAJ_22
2122	COPE_FUND_21	230 kV line	
2125	COPE_VLLD_21	230 kV line	COPE_VLLD_22
2128	CUES_VLLD_21	230 kV line	
2149	FUND_SMAR_21	230 kV line	FUND_SMAR_22
2179	CHIN_SABA_51	500 kV line	CHIN_SABA_52
2323	FUND_SABL_21	230 kV line	FUND_SABL_22
8980	SABA_TR_523_1	230/500 kV transformer	
27879	G_GUAJIRA1	230 kV Generator	G_GUAJIRA2
1647283	COPE_TR_523_2	230/500 kV transformer	
1647459	COPE_OCAN_51	500 kV line	
1647469	COP5_BOL5_51	500 kV line	
	SMAR-TERMOC	230 kV line	

Table 4 Lines/elements to consider in the contingency analysis

Thermal max 2019				Base case full grid		1	2	3	4	5	6	7	8	9	10	11
Disconnect Element\	Voltage kV	Area	Type	Without wind	With wind	CUES_GUAJ_21	COPE_FUND_21	FUND_SABL_21	CUES_VLLD_21	FUND_SMAR_21	CHIN_SABA_51	COPE_VLLD_21	SABA_TR_523_1	COPE_OCAN_51	COP5_BOL5_51	G_GUAJIRA1
SABL_TR_211	230/110	COSTA-ATLANTICO	sformer	NA	124.2	124.1	124.6	124.4	124.3	124.2	124.1	124.2	124.3	124.2	124.4	124.0
SABN_BARA_11	110	COSTA-ATLANTICO	Line	NA	113.6	113.6	114.0	113.8	113.7	113.6	113.6	113.7	113.7	113.6	113.8	113.4
FLOR_TR_13_1	110/34,5	COSTA-ATLANTICO	sformer	NA	104.4	104.4	104.4	104.4	104.4	104.4	104.4	104.4	104.4	104.4	104.4	104.4
FLOR_TR_13_2	110/34,5	COSTA-ATLANTICO	sformer	NA	104.4	104.4	104.4	104.4	104.4	104.4	104.4	104.4	104.4	104.4	104.4	104.4
COP_SVC11	11	COSTA-GCM	Node	NA	119.0	120.9	117.0	118.9	120.0	119.3	118.0	119.3	119.0	115.4	112.6	118.0
CODAZZI110	110	COSTA-GCM	Node	90.6	86.9	87.1	87.0	87.0	88.2	88.0	88.9	88.1	89.0	87.4	88.4	88.4
LAJAGUA110	110	COSTA-GCM	Node	85.4	78.2	78.3	78.2	78.3	79.6	79.5	80.5	79.5	80.5	78.7	79.9	79.9
LA_LOMA110	110	COSTA-GCM	Node	83.4	75.0	75.2	75.1	75.1	76.6	76.4	77.5	76.4	77.5	75.6	76.9	76.9
COP_SVC_TR_511	500/11	COSTA-GCM	sformer	NA	127.4	146.2	108.2	126.8	136.8	130.2	118.1	130.5	127.9			118.0
CUES_RIOH_11	110	COSTA-GCM	Line	NA	132.3	131.7	134.2	132.2	133.4	133.3	132.2	133.5	132.2	131.9	132.7	132.8
TR2-VALLEDUP	230/115	COSTA-GCM	sformer	NA	127.6	128.9	129.0	127.6	128.4	127.3	125.8	131.3	125.8	126.9	126.6	125.3
CODZ_VLLD_11	110	COSTA-GCM	Line	NA	128.0	127.8	127.9	127.8	125.7	126.0	124.3	125.9	124.3	127.2	125.2	125.2
SALG_VLLD_31	35	COSTA-GCM	Line	NA	124.7	126.3	126.4	126.4	124.9	125.1	123.9	125.0	123.9	124.1	124.6	124.6
TR1-VALLEDUP_13	110/34,5	COSTA-GCM	sformer	NA	106.9	108.3	108.3	108.3	107.0	107.2	106.2	107.2	106.2	106.4	106.8	106.8
SMAR_TR_213_2	230/115	COSTA-GCM	sformer	NA	101.4	101.5	101.5	101.3	102.4	104.4	101.4	102.3	101.4	101.5	101.4	
SMAR_TR_213_1	230/115	COSTA-GCM	sformer	NA	101.4	101.5	101.5	101.3	102.4	104.4	101.4	102.3	101.4	101.5	101.4	

Table 5 Contingency 2019 high load, thermal generation, wind and selected elements

Table 5 shows the load element in the cotingency analysis and the amount the criteria is violated 100 is rated load or voltage. Not all investigated contingency cases in Table 5 were converted. 34 violations as most for one outage were reported. No violation on 230 kV and 500 kV power grid elements is identified. The COPE_TR_523_2 500/230 kV transformer did not convert in the Neplan study implemented with the model provided. Consequently, it is not shown in the table. The non-conversion indicates the need of an additional 50/230 kV transformer in COPE wich is included in the *Plan, Generation – Transmission, 2012-2025.*

Hydro min 2019				Base case full grid		1	2	3	4	5	6	7	8	9	10	11	12
Disconnect Element\	Voltage kV	Area	Type	Without wind	With wind	COPE_TR_523_2	COPE_VLLD_21	CUES_VLLD_21	CUES_GUAJ_21	SABA_TR_523_1	FUND_SABL_21	COPE_FUND	FUND_SMAR_	G_GUAJIRA	CHIN_SABA_5	COPE_OCAN	COP5_BOL5_
TENERIFE66	66	COSTA-BOLIVAR	Node	93.1	115.8	115.5	115.8	115.8	115.8	115.7	115.7	115.8	115.9	115.9	115.4	115.2	112.8
CALAMAR66	66	COSTA-BOLIVAR	Node	92.8	107.4	107.1	107.4	107.4	107.4	107.3	107.3	107.4	107.5	107.5	107.0	106.8	
BOLIVAR66	66	COSTA-BOLIVAR	Node	NA	107.0	106.8	107.0	107.0	107.0	106.9	106.9	107.0	107.0	107.0	106.7	106.5	
VILLAESTRELLA66	66	COSTA-BOLIVAR	Node	NA	106.1	105.8	106.0	106.0	106.0	106.0	106.0	106.0	106.1	106.1	105.7	105.6	
S_JACINT66	66	COSTA-BOLIVAR	Node	94.9	105.4	105.1	105.4	105.4	105.4	105.3	105.3	105.4	105.4	105.5	105.0		
VALLEDUPAR34.5_	35	COSTA-GCM	Node	95.6	95.4	88.2											
LAJAGUA110	110	COSTA-GCM	Node	85.4	83.3	74.3	77.8	81.2	80.6	83.2	83.3	83.1	82.9	84.6	83.1	82.4	83.0
LA_LOMA110	110	COSTA-GCM	Node	83.4	80.9	71.6	75.3	78.9	78.2	80.9	81.0	80.8	80.6	82.3	80.7	80.1	80.7
CODZ_VLLD_11	110	COSTA-GCM	Line	NA	98.1	110.1	105.0	100.6	101.3								
CUES_RIOH_11	110	COSTA-GCM	Line	NA	101.2	107.6	104.9	103.7	104.2	101.2	101.2	101.3	101.6		101.4	101.8	101.4
SALG_VLLD_31	35	COSTA-GCM	Line	NA	97.0	105.8	102.2										
TR2-VALLEDUP	230/115	COSTA-GCM	sformer	NA	93.7	103.9											

Table 6 Contingency 2019 low load, hydro generation, wind and selected elements

Not all investigated contingency cases in Table 6 were converted. 241 violations most for one outage were reported. No violation on 230 kV and 500 kV level were identified. In many cases the wind production lowers the load in the power grid compared with the base case without wind. Only a few additional grid components are required.

3.5.3.3 Dynamic analysis

The dynamic analysis investigating if the wind farm turbines are able to stay connected after a failure, if the wind farm is oscillating with any of the existing generators and if the oscillation is damped. The dynamic analysis is also used to investigate the voltage variations due to loss of the wind farm and variations in voltage and reactive power consumption.

The dynamic studies have been done for the 2013, 2019 and 2025 cases.

For the 2019 case the discussion on the reactive power capability support (voltage) from the wind farm is important.

- Case A: 3-phase short circuit fault on 230 kV line "Cuestecita and Guajira"

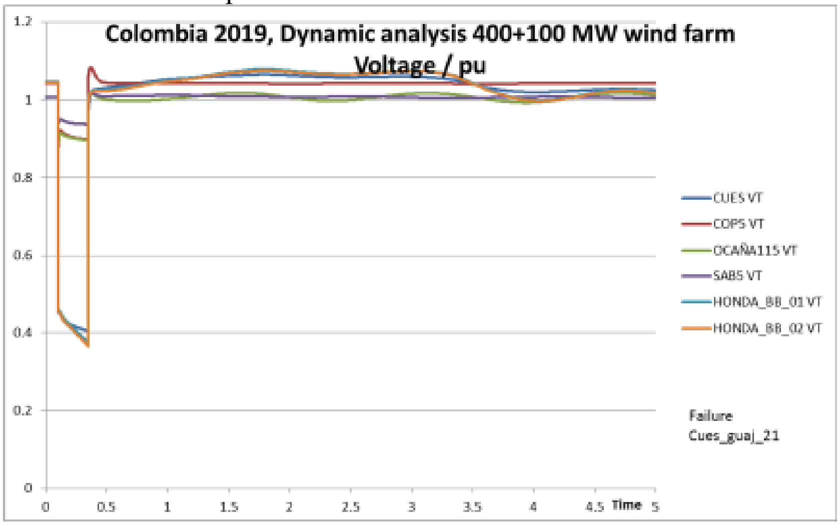


Figure 18 2019 failure on the Cuestecita Guajira transmission line, voltages

A 3 phase short circuit fault at 0.1 s is applied in the middle of one of the overhead power transmission lines between Cuestecita and Guajira. The transmission line is disconnected in both ends after 250 ms at 0.35 s, see *Figure 18*. The power from the wind farms is restored at approximately 0.7 pu of the original power after the fault is cleared and ramped up to full power within 3 seconds.The second transmission line between Cuestecita and Guajira takes the power. It is observed that no large or fatal oscillations occur between the wind farms generators and the existing generators. It is also observed that no voltage violations occur at the observed lines.

The voltage fluctuations at Ocaña are quite small and are not expected to impose problems for the continued operation of the system. (See *Figure 18* and *Figure 19*).

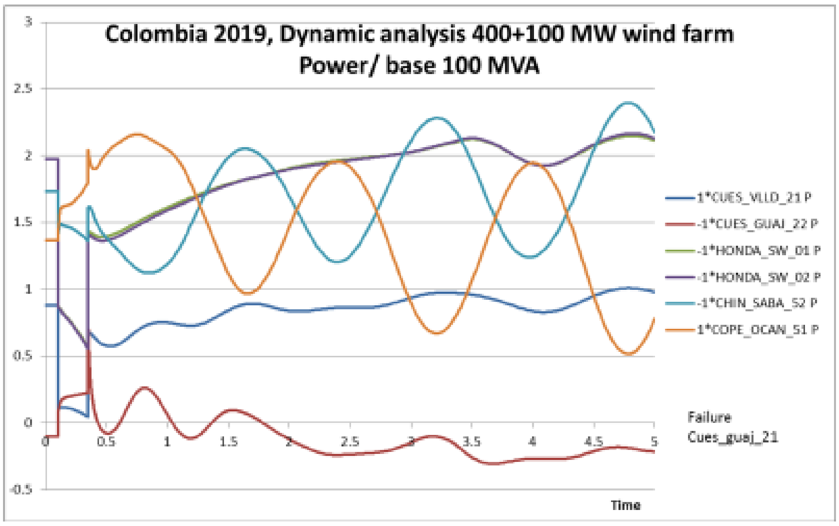


Figure 19 2019 failure on the Cuestecita Guajira transmission line, power

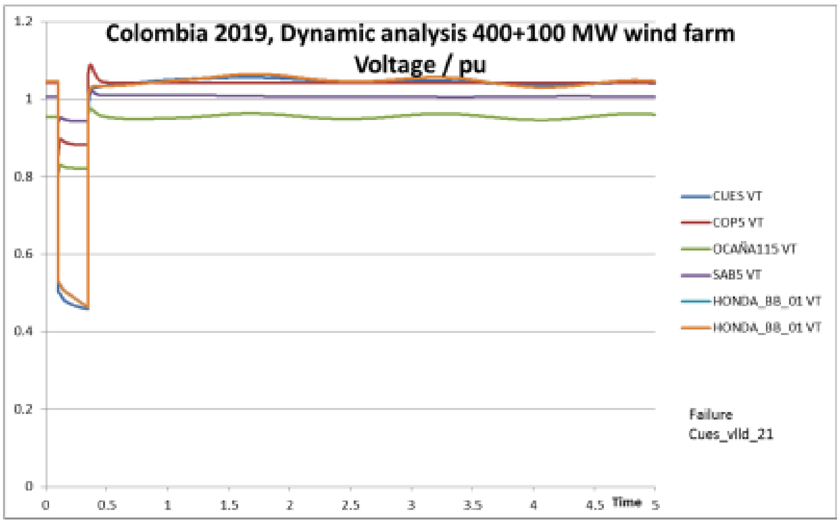


Figure 20 2019 failure on the Cuestecita Valledupar transmission line, voltage

- Case B: 3-phase short circuit fault on 230 kV line "Cuestecita and Valledupar"
  A 3 phase short circuit fault at 0.1 s is applied in the middle of one of the overhead power transmission lines between Cuestecita and Valledupar and the transmission line is disconnected in both ends after 250 ms at 0.35 s, see *Figure 20*. The power from the wind farm is restored at approximately 0.8 pu after the fault is cleared and ramped up to full power within 1.5 second, see *Figure 21*. The two remaining transmission lines between Cuestecita and Valledupar increase their power. It can also be seen that no big oscillations occurs between the wind farm generators and the existing generators. See *Figure 20* and *Figure 21*. There are inter-area oscillations on the 500 kV level.

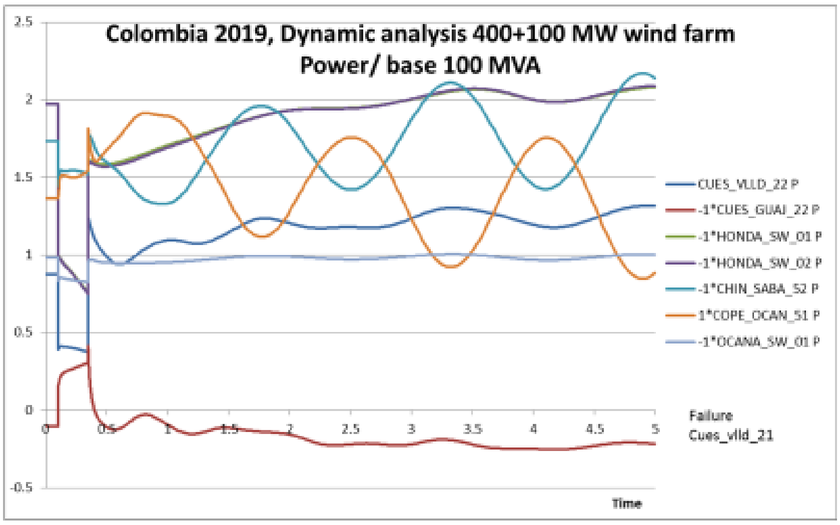


Figure 21 2019 failure on the Cuestecita Valledupar transmission line, power

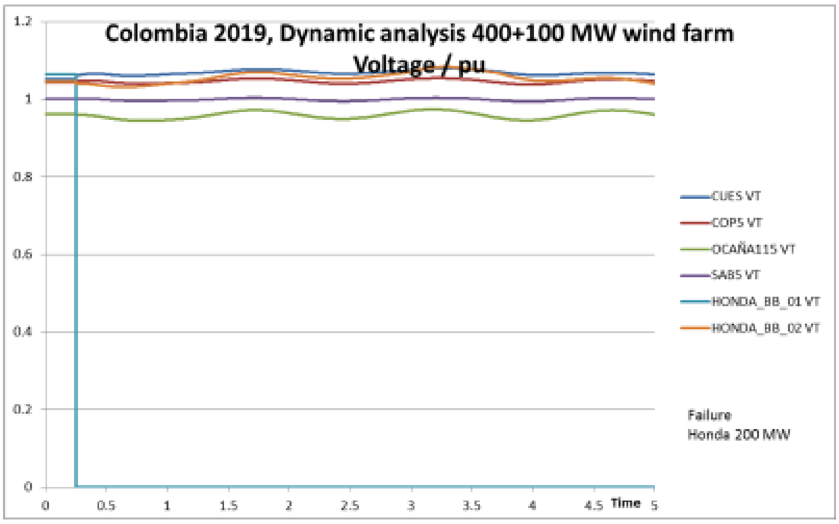


Figure 22 2019 Outage of 200 MW wind farm, voltages variations

The 200 MW wind farm is disconnected at HONDA SSt at 250 ms, no voltage variation is observed, see *Figure 22* and *Figure 23*. There are inter-area oscillations on the 500 kV level.

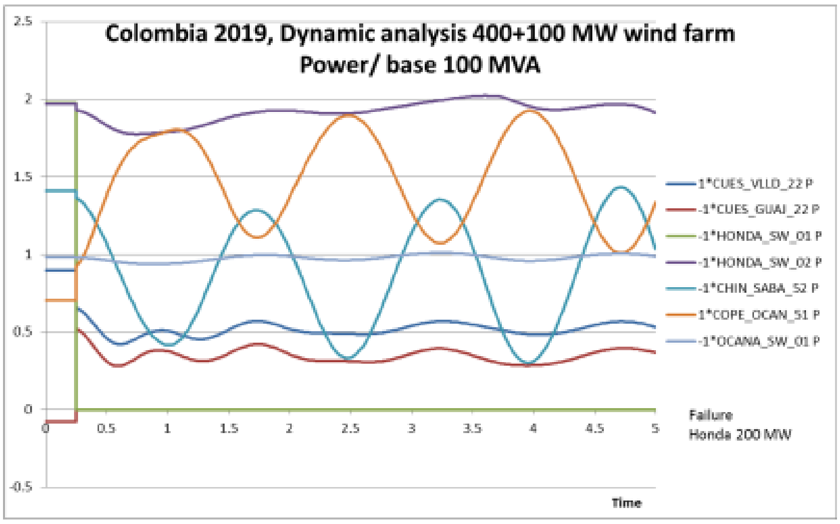


Figure 23 2019 Outage of 200 MW wind farm, power

3.5.3.4 Frequency analysis

The frequency analyses investigate the impact if a generating unit or a transmission line is disconnected from the power grid due to faulty operation. This study assumes that the wind farm are designed with a separate grid connection rated maximum 200MW, being smaller than the largest production unit in Colombia today.

It has not been possible to perform the frequency analysis for the complete Colombian power system, due to malfunctioning of the delivered dynamic model of the power system. Thus, the focus has been describing power variations with measurements originating from two similar and existing wind farm in the same size. The two Danish wind farms (Nysted 165 MW and Rødsand 2 207 MW) are feeding into the same grid connection point at 132 kV and only geographically separated by 4 km.

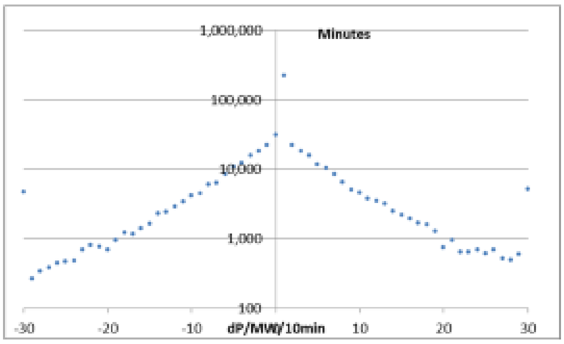


Figure 24 Changes in power production 10 minute average

Based on the measurements the changes for one year will have a distribution of 10 minutes power changes as shown in Figure 24 and 1 minute in Figure 26. One year has 525600 minutes. Changes bigger that 30 MW/10 min are summarised.

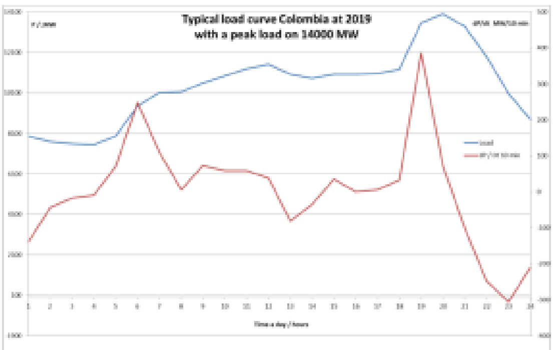


Figure 25 Changes in power production 2019 Colombia, 10 minute average

As seen in *Figure 25* the 10 minutes changes for the normal load in Colombia which the dispatch have to deal with based on 1 hours average, varies between

-300 MW/10 min to 400 MW/ 10min.

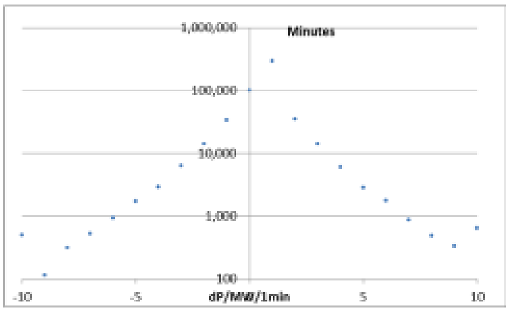


Figure 26 Changes in power production 1 minute average

3.5.3.5 Harmonic analysis

The harmonic generated from modern wind turbine types does normally not cause any problems. The different types and converters (in all type 3 and 4 wind turbines) makes it difficult to make a general calculation. The best approach is that the system operator and the wind developer agree to secure a maximum harmonic level at the grid connection point. Each wind developer shall then in his design, or in commissioning measurements prove that the agreed levels are not exceeded.

Wind energy converters must comply with standards like those described in EN 50160, IEEE 519 or IEC 61000. Especially harmonics can distort the grid and must not exceed the given limits. In practice, harmonics or sub-harmonics caused by the wind turbine are difficult to measure, because the grid itself also is distorted.

Therefor the design of the wind turbines shall aim at an overall harmonic distortion level below the limits specified by IEEE, EN or IEC standards. Both total harmonic distortion factor and individual harmonic distortions should be below this level.

The next example shows the Danish offshore wind farm 209 MW Horns Rev 2 with full scale converter wind turbines, connected to the grid through a 100 km cable.

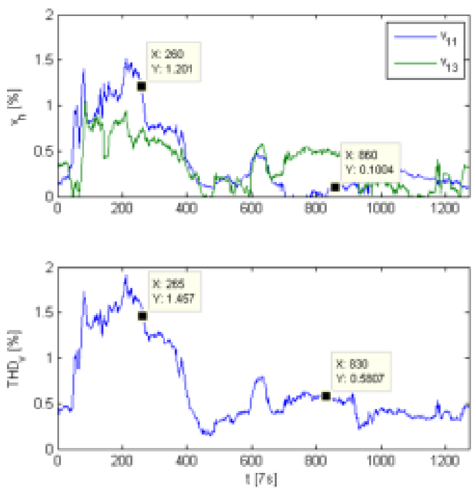


Figure 27 Voltage harmonics and total harmonic distortion at the point of common coupling in Horns Rev 2. Ref Kocewiak, Hjerrild, Bak

The wind farm is connected at 250x7s and starts producing the high harmonic voltage level before the WF is connected (mainly the 11th and 13th voltage harmonics become significant), but are strongly decreased when the WF is producing, as seen in *Figure 27 Voltage harmonics and total harmonic distortion at the point of common coupling in Horns Rev 2. Ref Kocewiak, Hjerrild, Bak.*

This behaviour of large wind farms is due to the fact that the WF changes the impedance at the PCC.

3.5.4 5x20 MW Wind farms – Santander Region

3.5.4.1 Steady state

Since the wind farm is aggregated 5x20 MW to 100 MW the wind farm is very similar to the aggregated model for the wind farm in Guajira.

The base building block from the 100 MW unit is used at the Ocaña wind farm and only the connecting transformer is changed.

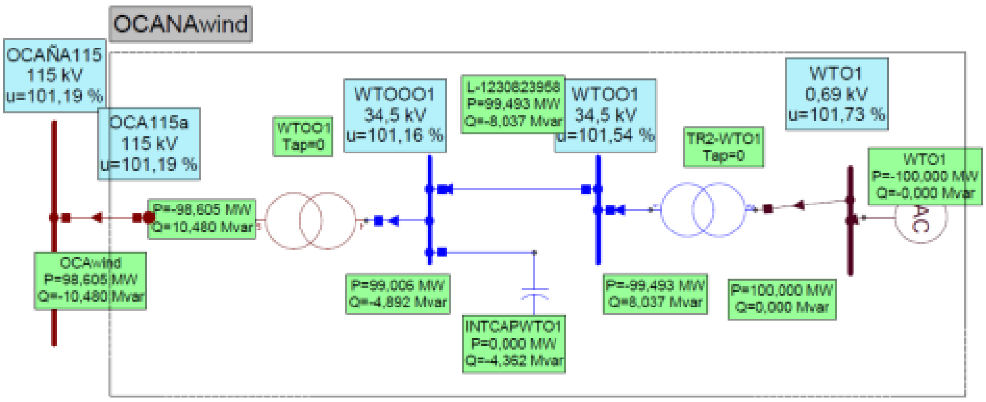


Figure 28 Ocaña 100 MW Wind farm aggregating

The 5x20 MW wind farms in Northeren Santander region will be aggregated as one 100 MW wind farm assumed to be connected to the OCAÑA 500/230/115 kV station at 34.5 kV voltage level.

The load scenarios to be used are described in Table 2.

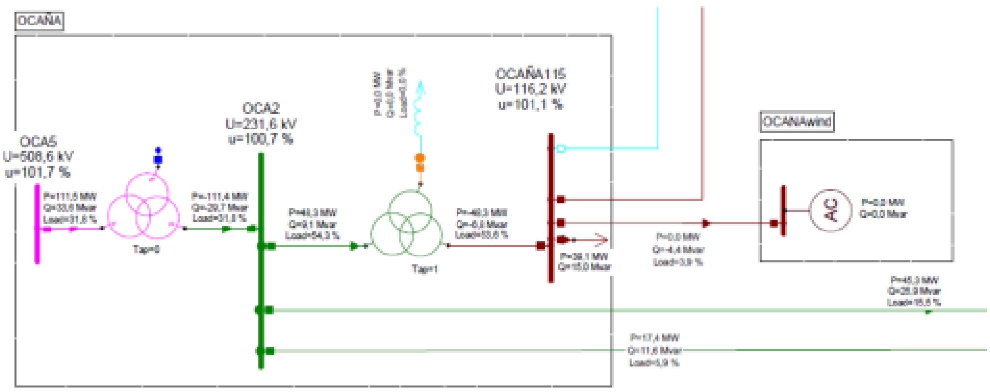


Figure 29 2019 Ocaña maximum load, thermal generation, no wind

The 5x20MW wind farm(s) connected at the 115 kV busbar at the Ocaña substation the wind will reverse the power through the 230/115 kV transformer, because the wind production exceeds the local load, see Figure 29 and Figure 30,

No additional upgrade is expected in 2019. In 2025 the 230/115 kV transformer is not sufficient and an additional transformer is required. See also the Figure 13

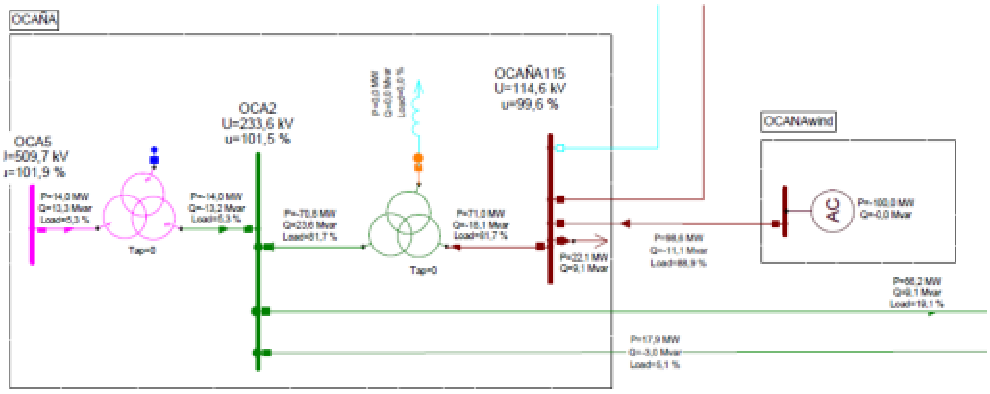


Figure 30 2019 Ocaña minimum load, hydro generation, wind

4 AEP & Financial Feasibility Analysis

4.1 Introduction

In accordance with the terms of reference for the assignment AEP calculations for two turbine types and a cost structure and economic calculations should be carried out for the two designated regions La Guajira and Santander respectively.

However, as it has turned out to be impossible to obtain useful wind data measured on MET masts for the Santander region, calculations for this region have not been performed.

Consequently only an indicative wind study for a defined site in the La Guajira region is presented along with financial assumptions, cash flow calculations and conclusions on economic feasibility.

Based on the received information and data a wind study and financial feasibility analyses were carried out for a fictive 400 MW wind power project located in La Guajira region.

4.2 Wind resource

The wind resource and average annual energy production (AEP) for a 400 MW project in La Guajira region has been analysed. It is noted, however, that as this is merely an indicative calculation for a fictive project, specific site conditions such as extreme wind and turbulence have not been taken into account

It is also noted that the presented wind study and AEP estimate for the fictive project must not be considered as a study of bankable quality. The reason is that the available information about the measurements provided by UPME is very limited and not applicable for estimation of the uncertainty of the measured wind. Furthermore, the measurements have not been inspected by COWI and therefore, a thorough assessment of the data quality is not possible. Finally, the uncertainty of many other parameters (e.g. final location of project, selected turbine, O&M etc.), which cannot be determined at this point, will have an influence on the joint uncertainty of the AEP estimate. Therefore, a joint uncertainty of the estimated AEP has not been presented.

4.2.1 Wind data

Hourly wind direction and wind speed data from a 10 m mast covering the eight and half year period from January 2001 to June 2009 and hourly wind direction and wind speed data from a 50 m mast covering the six years and seven months period from January 2007 to July 2013 has been provided. Further, production and availability data from the existing Jepirachi wind farm covering the period 2004 – 2012 has been provided. These data combined has been used as a basis for the analysis of the wind resource.

Locations of the met masts and the Jepirachi wind farm are shown in the figure below.

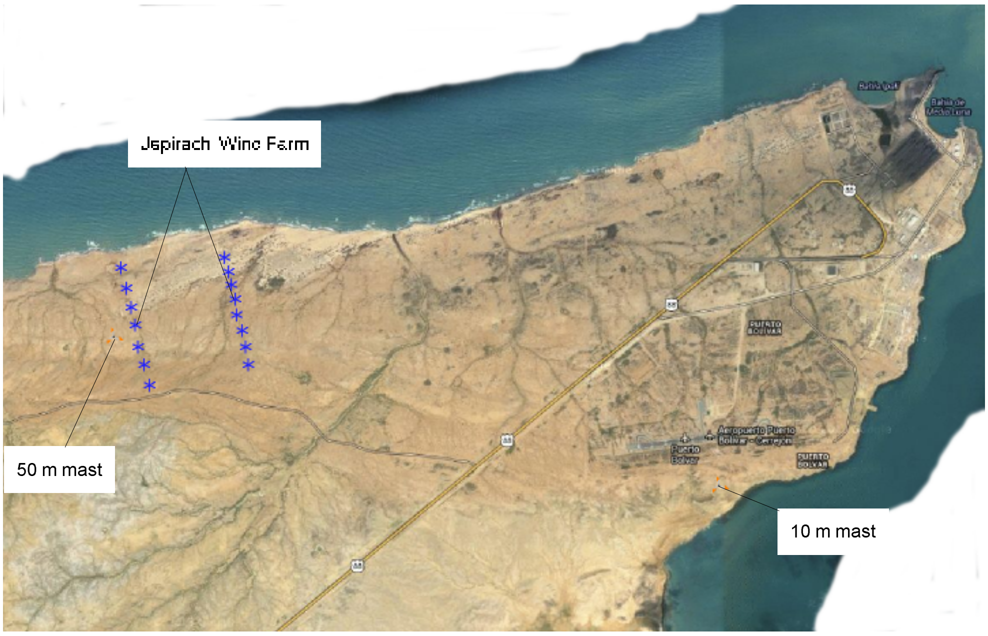


Figure 31: Location of 10m and 50m masts and Jepirachi Wind Farm

4.2.2 Long-term correction

MERRA data[1] covering a 30-year period has been applied in the analysis for long-term correction. A correlation coefficient $R^2 = 0.85$ based on monthly mean wind speeds has been found between the MERRA data and the 50 m mast data. This is an acceptable correlation for long-term correction.

[1] NCAR and MERRA re-analysis data is based on several different meteorological sources (satellites, balloons, meteorological stations etc.) and covers the entire world with a grid resolution of 2.5 and 1 degrees, respectively.

By comparing the 30 year annual mean wind speed with the annual mean wind speed during the 12 years based on the MERRA data, it is seen that the annual mean wind speeds during the two periods are identical. This corresponds to a long-term correction of the 12 years onsite data of 1.0.

4.2.3 Wind analyses

The 12 years on-site data covering the period July 2001 to June 2013 - long-term corrected with the 30 years MERRA data - is used as basic wind for the following wind analyses and energy production estimate for the fictive wind project.

It is found that there is a

- general high wind period during Jan-Aug and low wind period during Sep-Dec, with a maximum monthly wind of 11.0 m/s in May 2003 and a minimum monthly wind of 3.5 m/s in Oct 2007.

- a significant variation in the annual mean wind speed, which corresponds to a standard deviation of 12.5 per cent. It should be noted that this yearly variation in the wind speed is significantly higher than usually seen for other wind project sites.

The 12 year long-term corrected time series representing the wind measured at the 50 m mast are transformed into the Weibull distributions[2].

The Weibull parameters 50 m above ground level are given by:

- Weibull A: 9.1
- Weibull k: 3.03
- Weibull mean wind speed: 8.2 m/s

The prevailing wind direction is E and ENE.

4.3 Annual Energy Production (AEP)

The annual energy production (AEP) estimate for a possible future 400 MW wind power project located South-West of the existing Jepirachi wind farm has been calculated based on the available wind data.

The AEP calculations are carried out in WindPro, a program which calculations are based on WAsP flow model.

The following two wind turbines have been chosen:

[2] Traditionally way of presenting the wind distribution used for wind energy

› Gamesa G90 2 MW, hub height 78 m (200 x 2 MW)

› Vestas V112 3 MW, hub height 84 m (134 x 3 MW)

With a mean wind speed of 8.2 m/s at 50 m above ground and estimated mean wind speed at 78 m hub height of 9.4 m/s and at 84 m hub height of 9.6 m/s, the area can be characterised as a medium-to-high wind area. However, as mentioned earlier specific site conditions (e.g. extreme wind) have not been taken into account when choosing the turbine types.

In order to estimate the energy production delivered to the grid, some losses must be considered. At this stage the following losses – besides the calculated wake loss - are estimated based on experience with similar projects:

- Wind turbine availability loss: 4%
- Electrical loss: 4%
- Grid loss: 2%
- Power curve loss: 2%

The following AEP estimates have been obtained.

200 x Gamesa G90 2 MW, hub height 78 m		
AEP gross		2138 GWh/y
Wake loss[3]	12.2%	261 GWh/y
AEP park		1877 GWh/y
Losses:		
WTG availability	4%	
El Loss	4%	
Grid loss	2%	
Power curve loss	2%	
Total loss	11.5%	216 GWh/y
AEP-net		**1661 GWh/y**
Net Capacity factor		47 %
Full Load hours:		4153 hours

Table 7: AEP estimate for 200 Gamesa G90 2 MW, hub height 78 m

[3] Only wake loss from the new turbines is included as the location is not fixed. Possible wake loss from Jepirachi turbines will be insignificant

134 x Vestas V112 3 MW, hub height 84 m		
AEP gross		2249 GWh/y
Wake loss[3]	11.2%	252 GWh/y
AEP park		1997 GWh/y
Losses:		
WTG availability	4%	
El Loss	4%	
Grid loss	2%	
Power curve loss	2%	
Total loss	11.5%	229 GWh/y
AEP-net		**1768 GWh/y**
Net Capacity factor		50 %
Full Load hours:		4397 hours

Table 8: AEP estimate for 134 Vestas V112 3 MW, hub height 84 m

4.4 Investment and operation budget

Based on the information provided the selected turbine types and on the experience of COWI, the following investment budget has been established:

CAPEX item	US$
EPC contract	720,000,000
Transmission & Grid connection	90,000,000
Development cost	36,000,000
CDM development cost	50,000
TOTAL	**846,050,000**

Table 9: CAPEX for a 400MW wind farm

Total OPEX (excl. taxes) is estimated to be approx. US$ 51.5 million per year

For further details of establishing the CAPEX and OPEX please refer to the study report 02.

4.5 Income

For a wind power project in Colombia there are different parameters related to income generation.

First of all the electricity will be sold on the market. In the calculations an average sales tariff of US$ 65 per MWh has been used.

In addition to the electricity tariff, wind power projects may receive a firm energy payment called a reliability charge. For the given project the basis for calculating the reliability charge is 6% * 8760 hours * 400 MW = 210,240 MWh. The level of the reliability charge per MWh is informed to be US$ 15.

Finally, if registered as a CDM project, the project can sell certified emission reductions (CERs). A CER price of US$ 1 per CER has been used in the financial calculations.

4.6 Operating Costs

The operating costs are comprised of

- Operation & Maintenance
  Wind Farm
  A full O&M service agreement is offered at prices UD$ 26.000-US$ 55.000 per installed MW per year. A figure US$40.000 per MW is used in the calculations in the high end but reduced since the huge marked potential is assumed to attract service providers.

  Power Grid Infrastructure
  Colombian developers have informed that transmission line and substation O&M will be around US$ 9,500 per MW installed per year

- Administrative Cost
  Apart from the O&M staff hired in the service agreement also permanent administrative staff and site personal will be required. As rough estimate four full-time employes are assumed at a total cost ca. US$110.000 per year.

- Insurance Cost
  0.25% of the EPC investment is anticipated

- CERE Fee
  The CERE fee is used to pay for the Reliability Charge.
  The CERE fee used for the analyse is US$ 16.9 per MWh (2013 average)

- Regulatory fees and environmental cost
  Colombian developers have informed that tegulatory fees and environmental cost will be around US$ 11,000 per MW installed per year.

- Income Tax
  A 15 years tax-exemption period is anticipated in compliance with Law 788 of 2002. From year 16 and onwards the project will have to pay an income tax of 33%..

- Depreciation
  A 20-year linear depreciation has been assumed in the financial analysis and is considered after the 15-year tax-exemption period where the income taxes are considered.

4.7 Financial analysis

In the financial analyses the internal rate of return has been calculated for the pure investment without financing, and for the investment with financing on market terms.

For the pure investment without financing the following results have been found:

WTG type	Item	Result
2 MW	IRR	9,1 %
	NPV net income	463.371.420
3 MW	IRR	10,3%
	NPV net income	562.257.588

Table 10: IRR and NPV for the base case pure investment

From this, it can be seen that based on the current situation and on the assumptions made, a 400 MW wind power project in La Guajira can be considered financially viable. Compared with the IRR expectations from developers the result is aligned with their target, and compared with the base rate from the Central Bank of Colombia of 3.25 %, the IRR is well above this rate.

For the investment with market financing:

WTG type	Item	Result
2 MW	IRR	17,1%
	NPV net income	562.082.629
3 MW	IRR	19,5%
	NPV net income	661.695.106

Table 11: IRR and NPV for the base case with market financing

WTG type	Item	Result
2 MW	IRR	16,6%
	NPV net income	646.733.049
3 MW	IRR	18,8%
	NPV net income	746.723.730

Table 12: IRR and NPV for the base case with alternative market financing

With both types of market based financing the IRR in the base case improves significant

4.7.1 Sensitivity analyses

To investigate the sensitivity of the investment different sensitivity scenarios have been carried out on selected parameters as being tabled below.

	Base Case	Scenario A	Scenario B	Scenario C
ENFICC	6%	10%	20%	30%
Tariff	89,7 $US/MWh	-10%	+10%	
Investment		-10%	-20%	
Power Connection	Included	Not included	Not included	
Depreciation	None	Considered in relation to income tax.		

The sensitivity analyses have been carried out on an "all other things being equal" basis. The results are shown in the two tables below one for each production scenario.

2MW	NPV	IRR	LCoE
Base case without fin.	463.371.420	9,14%	92,26
Base case with fin.	562.082.629	17,06%	77,75
Base case with fin. alternative	646.733.049	16,64%	76,53
ENFICC 10% without fin.	491.598.487	9,47%	92,26
ENFICC 10% with fin.	590.309.696	17,77%	77,75
ENFICC 10% with fin. alternative	674.960.116	17,25%	76,53
ENFICC 20% without fin.	562.166.154	10,28%	92,26
ENFICC 20% with fin.	660.877.363	19,56%	77,75
ENFICC 20% with fin. alternative	745.527.784	18,82%	76,53
ENFICC 30% without fin.	632.733.821	11,07%	92,26
ENFICC 30% with fin.	731.445.030	21,37%	77,75
ENFICC 30% with fin. alternative	816.095.451	20,40%	76,53
Tariff -10% without fin.	266.968.199	6,79%	92,26
Tariff -10% with fin.	365.679.408	12,17%	77,75
Tariff -10% with fin. alternative	450.329.829	12,44%	76,53
Tariff +10% without fin.	659.774.640	11,37%	92,26
Tariff +10% with fin.	758.485.849	22,06%	77,75
Tariff +10% with fin. alternative	843.136.270	21,02%	76,53
Investment -10% without fin.	538.964.547	10,61%	86,88
Investment -10% with fin.	646.648.852	20,77%	72,90
Investment -10% with fin. alternative	723.735.214	19,88%	71,79
Investment -20% without fin.	614.557.675	12,33%	81,50
Investment -20% with fin.	731.215.075	25,34%	68,04
Investment -20% with fin. alternative	800.737.379	23,95%	67,04
Power Interconnection cost not included without fin.	553.504.476	10,92%	85,85
Power Interconnection cost not included with fin.	662.705.184	21,56%	71,96
Power Interconnection cost not included with fin. alternative	738.350.773	20,58%	70,88
Depreciation not considered without fin.	463.371.420	9,14%	92,26
Depreciation not considered with fin.	525.651.555	16,81%	77,75
Depreciation not considered with fin. alternative	610.301.976	16,41%	76,53

3MW	NPV	IRR	LCoE
Base case without fin.	562.257.588	10,25%	88,03
Base case with fin.	661.695.106	19,50%	74,33
Base case with fin. alternative	746.723.730	18,77%	73,18
ENFICC 10% without fin.	591.405.782	10,58%	88,03
ENFICC 10% with fin.	690.843.300	20,25%	74,33
ENFICC 10% with fin. alternative	775.871.923	19,42%	73,18
ENFICC 20% without fin.	664.276.266	11,38%	88,03
ENFICC 20% with fin.	763.713.784	22,11%	74,33
ENFICC 20% with fin. alternative	848.742.407	21,06%	73,18
ENFICC 30% without fin.	737.146.750	12,18%	88,03
ENFICC 30% with fin.	836.584.267	23,99%	74,33
ENFICC 30% with fin. alternative	921.612.891	22,73%	73,18
Tariff -10% without fin.	353.202.264	7,82%	88,03
Tariff -10% with fin.	452.639.782	14,27%	74,33
Tariff -10% with fin. alternative	537.668.405	14,23%	73,18
Tariff +10% without fin.	771.312.913	12,54%	88,03
Tariff +10% with fin.	870.750.430	24,88%	74,33
Tariff +10% with fin. alternative	955.779.054	23,52%	73,18
Investment -10% without fin.	638.228.681	11,78%	82,95
Investment -10% with fin.	746.684.160	23,50%	69,74
Investment -10% with fin. alternative	824.110.905	22,30%	68,69
Investment -20% without fin.	714.199.774	13,59%	77,87
Investment -20% with fin.	831.673.215	28,43%	65,16
Investment -20% with fin. alternative	901.498.081	26,74%	64,21
Power Interconnection cost not included without fin.	652.390.644	12,10%	82,01
Power Interconnection cost not included with fin.	762.317.662	24,33%	68,89
Power Interconnection cost not included with fin. alternative	838.341.454	23,04%	67,86
Depreciation not considered without fin.	562.257.588	10,25%	88,03
Depreciation not considered with fin.	625.102.117	19,31%	74,33
Depreciation not considered with fin. alternative	710.130.740	18,58%	73,18

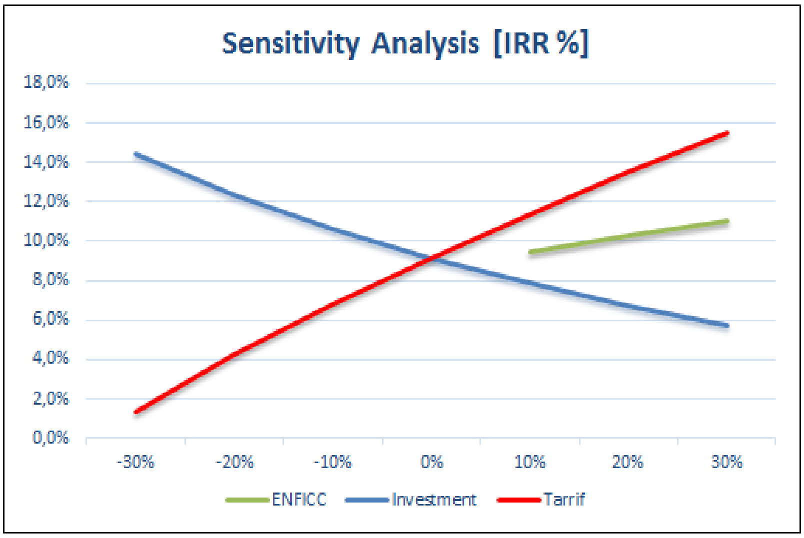
From the above tables it can be seen that the

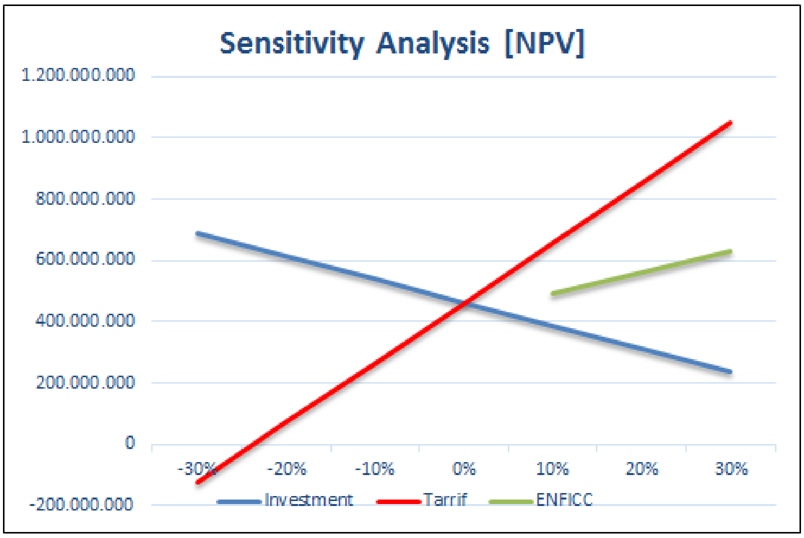
- Tariff & investment cost
  IRR is very sensitive to changes in the tariff and the investment cost.

- ENFICC
  IRR is also sensitive to changes in the ENFICC but to a lesser extent than for the two other parameters.

- Depreciation
  IRR & NPV are not significantly affected by the depreciation

A more illustrative sensitivity analyse for the 2MW WTG without financing is shown in the figures below when a change in the ENFICC, Investment and Tariff is introduced. (It is noticed that the ENFICC is 6% in the base case scenario and negative ENFICCs not apply).


Sensitivity Analysis [IRR %]
18,0%
16,0%
14,0%
12,0%
10,0%
8,0%
6,0%
4,0%
2,0%
0,0%
-30%
-20%
-10%
0%
10%
20%
30%
ENFICC
Investment
Tarrif


Sensitivity Analysis [NPV]
1.200.000.000
1.000.000.000
800.000.000
600.000.000
400.000.000
200.000.000
0
-200.000.000
-30%
-20%
-10%
0%
10%
20%
30%
Investment
Tarrif
ENFICC

4.8 Levelized cost of energy

Levelized cost of energy (LCoE) is the price at which electricity must be generated from a specific source to break even over the lifetime of the project.

Levelized cost of energy for the project has been estimated. In order to reach the expectation of 10% IRR, the required tariff for the different cases would be:

Case	USD/per MWh 2MW	USD/per MWh 3 MW
Pure investment	92.29	88.06
Base case market financing	77.75	74.33
Alternative market financing	76,53	73.18

This shows that a rise in the tariff per MWh (from the current average of USD 65 per MWh) is required all other things being equal in order to reach an IRR of 10%.

5 Market and Regulatory Aspects

5.1 Wind/Hydro Correlation and complementarity

The wind/hydro complementarity analyse investigates the relationship between the

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

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

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

The complementarity study considers wind energy production facilities in the Northern La Guajira province and selected hydro plants.

5.1.1 Wind speed analysis

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)

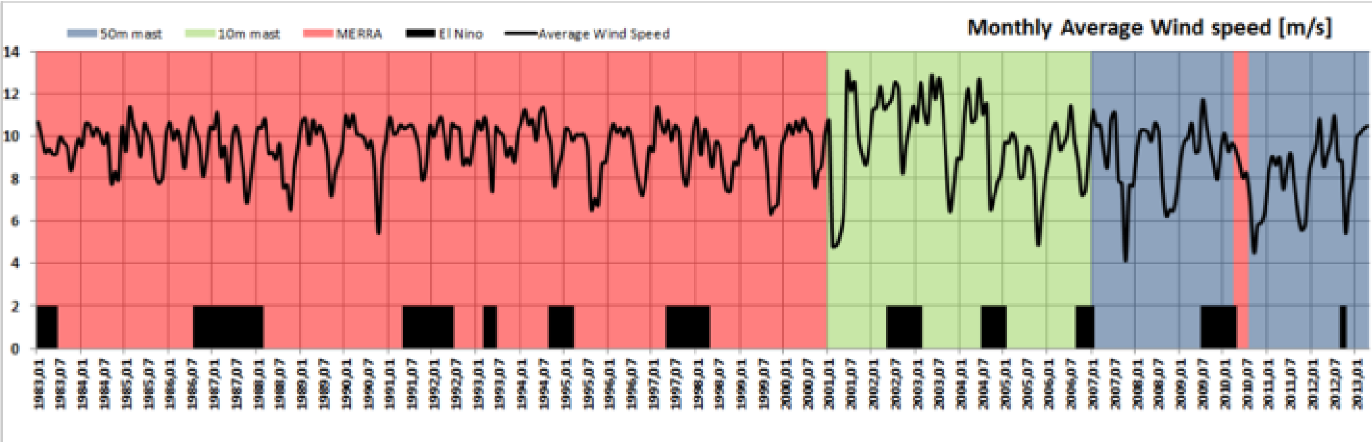
Also long-term satellite wind data "MERRA" from the time span 1983 – 2013 have been used for yearly correction and the elaboration of a full wind data series covering the years 1983-2013. Reference is made to progress study report 02: AEP and Financial Feasibility section 2.1.5.

Three data series (200 x 2MW, 134x3MW & 15x1,3MW) with 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

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

energy production correlation and complementarity**.** 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. (The average wind speed increases with larger hub height).

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



The standard deviation of the monthly average wind speed for the three time windows (based on different basis) 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 explained by the 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

› 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"

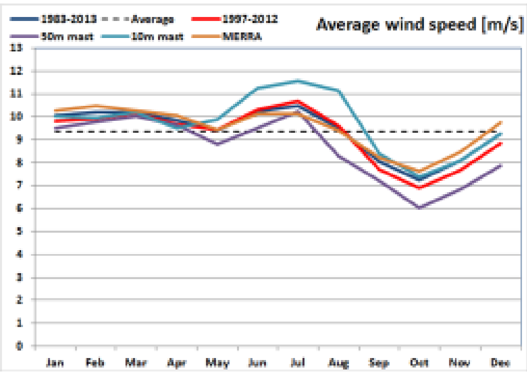
The average monthly wind speed distribution over the years 1983- 2013 is shown beside.

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 monthly average wind speed for the years 1997 – 2012 have also been analysed.

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 of the different scenarios and for all the years 1983- 2013 is shown below. The general trend in the monthly distribution over the year is the same.

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

Above observations are relevant for the further analyse of the wind/hydro complementarity-

5.1.2 Wind Energy Analysis

The basis for the wind energy production is established from the wind series through the years 1983-2013 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"

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 the wake loss impact on the wind speed. Thus a 1 hour data series for the wind farm energy production is established and the net energy production delivered to the power grid can be computed by:

E_{WTG}: Gross energy production from all WTGs
(Wake losses & 2% power curve losses considered)
- ΔP_{34kV}: Power losses in 33kV cables within the wind farm
- ΔP_{WTG_trans}: Power losses in the WTG 0,69/33 kV transformers
- ΔP_{SS_trans} : Power losses in the 33/220 kV transformers

E$_{230kV}$: ***Energy supply to 230 kV transmission line***
- ΔP$_{230kV\ ohl}$: Power losses in the 230 kV transmission line
E$_{PCC}$: Energy supply to the grid at the delivery point

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

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.*

The AEP calculation assumes an overall yearly availability 96% for the wind farms being adopted for the wind/hydro complementarity analyse.

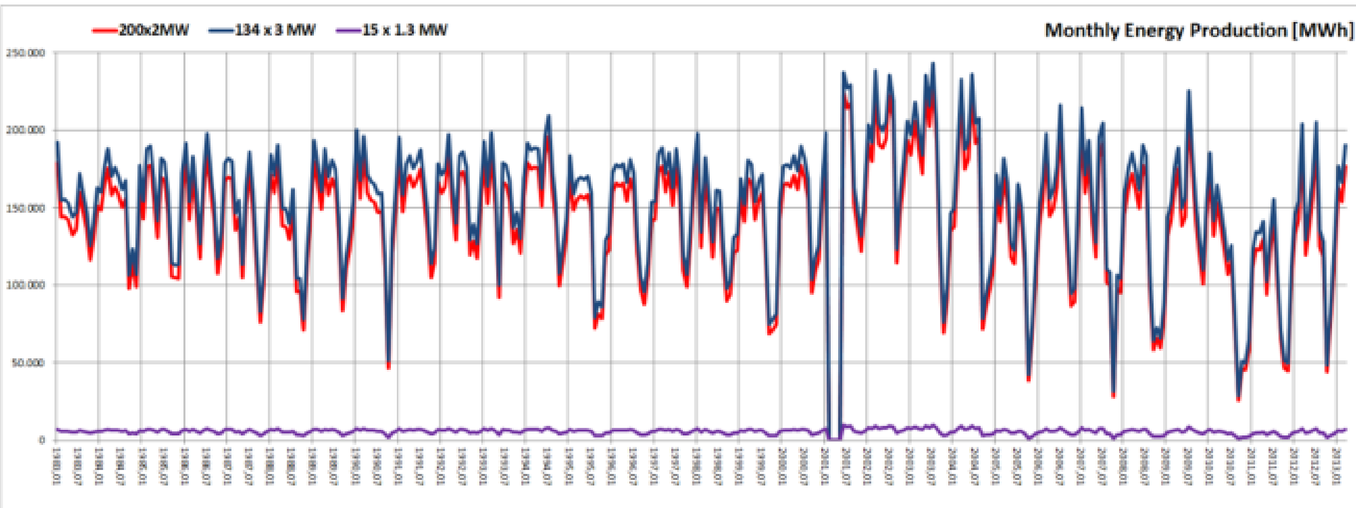
The availability is differentiated over the months in relation to the % average wind speed since the planned maintenance work should be planned in the months (May-Aug-Sep-Oct-Nov-Dec) were lowest wind speed occur.

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

Wind Speed Analyse and Availability

	1983-2013 Average [m/s]	Wind speed [% of average]	Availability assumed [%]
Jan	10,06	107,2%	98,0%
Feb	10,21	108,8%	98,0%
Mar	10,21	108,8%	98,0%
Apr	9,86	105,1%	98,0%
May	9,39	100,0%	94,0%
Jun	10,24	109,1%	98,0%
Jul	10,46	111,5%	98,0%
Aug	9,52	101,4%	94,0%
Sep	8,06	85,9%	94,0%
Oct	7,26	77,4%	94,0%
Nov	8,07	86,0%	94,0%
Dec	9,28	98,9%	94,0%
Year	**9,38**	**100,00%**	**96,00%**

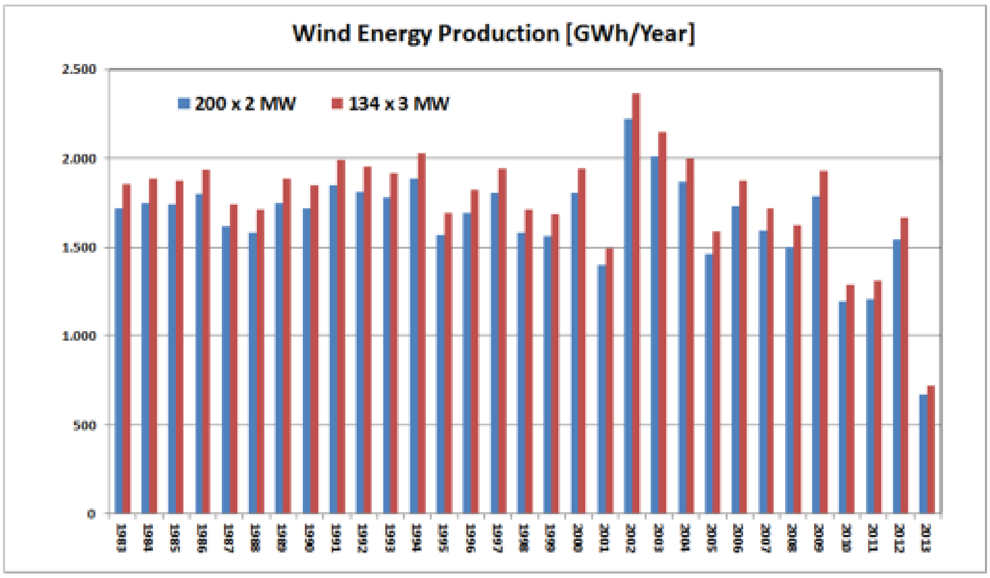
Max	10,46	111%	98%
Min	7,26	77%	94%



A significant flucturation of the monthly energy production [MWh] is observed with the extreme minimums in 2001[4] and 2007. A simple statistic analysis of the monthly and yearly energy production supplied to the grid at the delivery point in the Cuestecita station through a 131 km 230 kV transmission line is shown below:

	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 [MWh]			
Maximum	9.578	229.781	242.783
Minimum	9.947	25.643	28.581
Average	5.559	141.124	152.010
Standard Deviation	1.628 29,3%	38.969 27,6%	40.936 26,9%
Yearly Energy Production [GWh]			
Maximum	90	2.200	2.365
Minimum	46	1.191	1.293
Average	67	1.691	1.822
Standard Deviation	9 13,1%	203 12,0%	212 11,6%

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



[4] The wind data measurements reported from Feb-May in year 2001 are faulty and not used in this report.

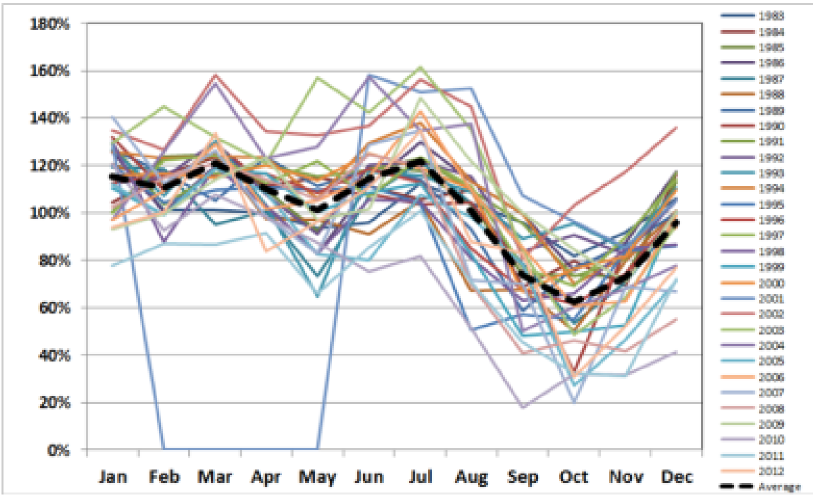
5.1.3 Wind Energy - Monthly Distribution

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 normalised distribution of the average energy production by the 200 x 2,0 MW wind farm is illustrated below for each year in 1983-2013 (March month inclusive).

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

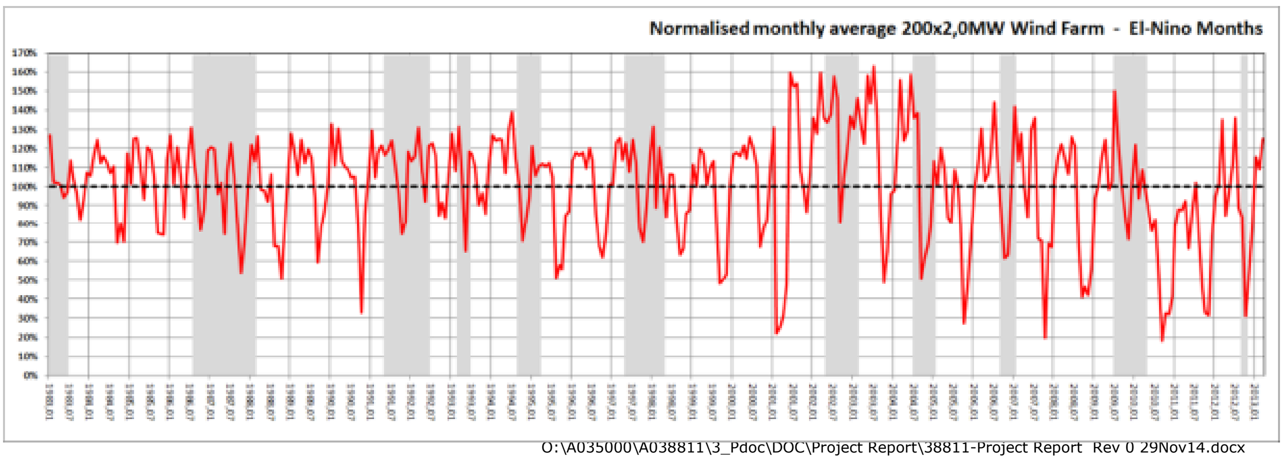
Above average: **Jan→Jul**
Below average: **Aug →Dec**



5.1.4 Wind Energy - El-Niño phenomena

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 following figure.

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.

5.1.5 Hydro Generating Plants

The energy 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.

This study includes generating plants selected by UPME.

Six power plants were appointed by UPME. Two power plants (ALBAN & URRA) were eliminated from the study since production data for these units not are reported for all months in the timespan between 1995 and 2013.

Consequently the analyse of the hydro in-flow and energy production complementary with the wind farm is based on the four 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

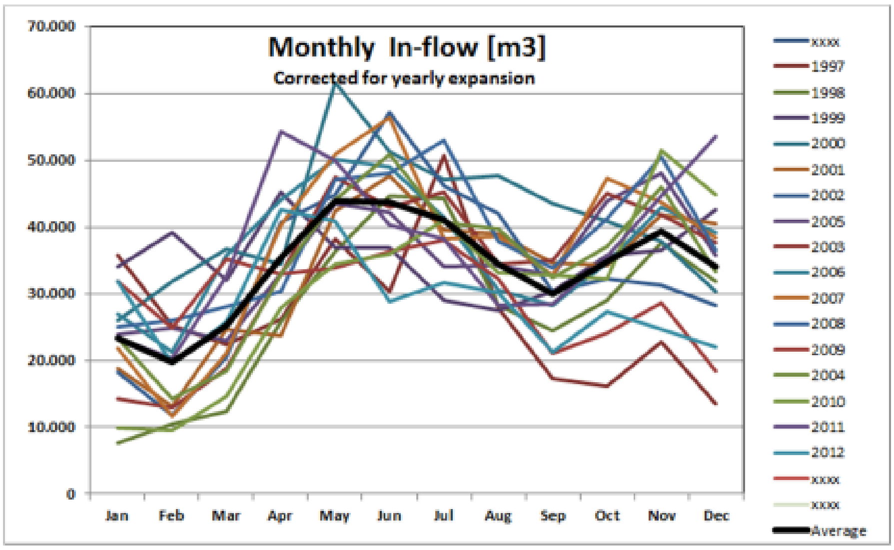
5.1.6 Hydro Data Analysis – River Discharges

The wind/hydro complementarity analysis implemented for the wind speed vs. river inflow is based on all the rivers measured and will also focus on the particular river that corresponds to the selected hydro power plants.

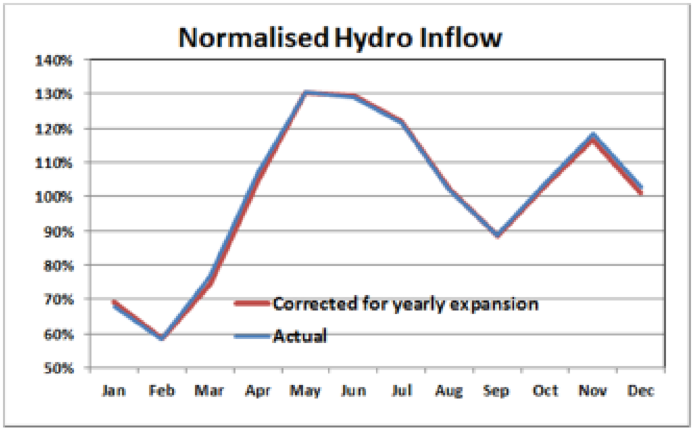
5.1.6.1 River Discharges – All Rivers

The monthly distribution of the water flow [m3/s] has been reported in the text file "Aportes Rios Caudal dia.txt" for the years 1997 - 2012. 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. The data has it origin from 26 different rivers in Colombia and from an increasing number of measurement (Starting with 19 in 1997).

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



The overall (complete Colombian pool of Hydro power plants) normalised monthly average of the in-flow distribution expressed in % of the monthly average are indicated in the graph and listed in the table and 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	35.317
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												
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%*

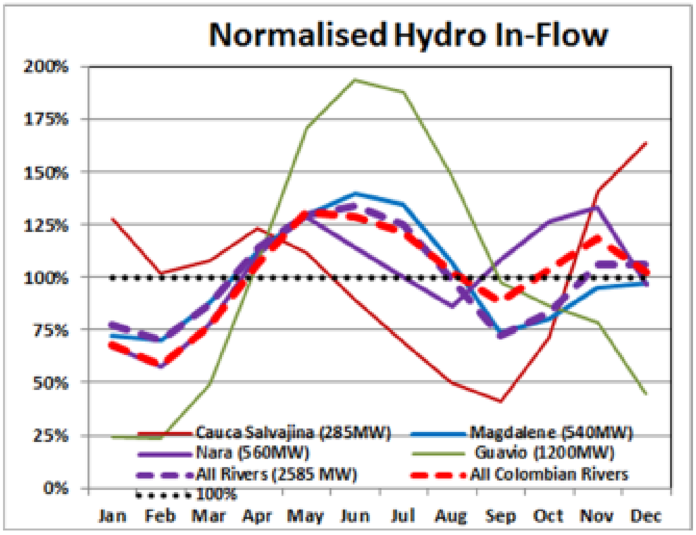
This % distribution will be used for the later complementarity analyse in relation to the wind speed.

5.1.6.2 River Discharges – Selected Rivers

The Hydro generating plants selected by UMPE for the study show deviating behaviour when the average monthly production for All Colombian rivers and the water in-flow for the particular river are compared.

Consequently, an analysis of the water in-flow reported for each of the relevant rivers has been implemented and is summarised.

The normalised hydro in-flow for each selected and All Colombian rivers are illustrated below.



Nara, Magdalene and Guavio rivers correlate quit 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 by a calculated correlation factor to all Colombian rivers (-0,02) practically equal to zero.

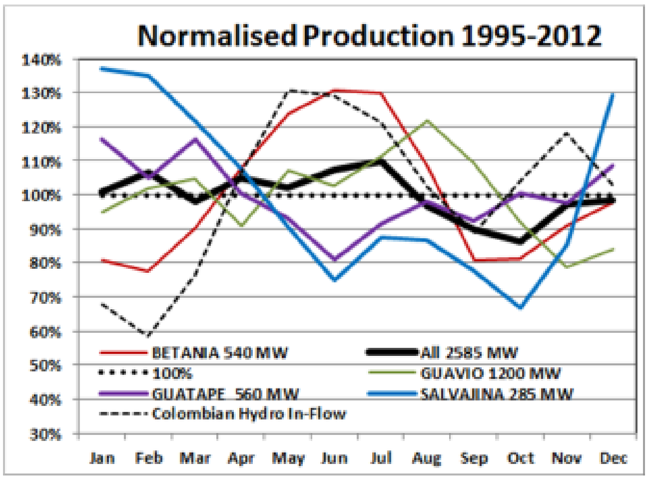
The Gavio River has maximum 200% and minimum 25% normalised water-in-flow that is significant and thus the most fluctuating river.

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

5.1.7 Hydro Power Production Analysis

The actual production reported for each the selected hydro power plants have been analysed on a monthly basis. Reference is given to Study Report 03 and Appendix A 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 no 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

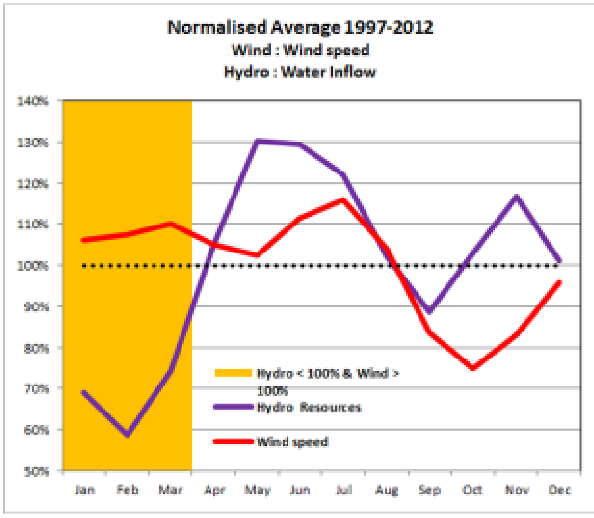
5.1.8 Complementarity Analysis

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"***.

5.1.8.1 Hydro inflow "All Colombian Rivers" vs. Wind Speed

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



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".

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

The actual distribution of favourable wind months thougth the year for the 1997-2012 time window (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 prevailing in Jan-Feb-Mar possible Apr and to a less extent in Dec as well. The occurance of El-Niño months is also indicated (marked in yellow). No interrelation between the El-Niño months and the "favourable wind months" is observed.

5.1.8.2 Hydro inflow "Actual Rivers" vs Wind Speed

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 identified 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.

5.1.8.3 Hydro vs. Wind Production "Average Month"

The wind/hydro complementarity is analysed by comparing the actual reported hydro production for each of the selected hydro generation units and the total pool with the calculated wind production from the 200x2,0 MW wind farm in the years Aug 95-Dec 12.

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 calculated production data from the 400MW wind farm and the actual 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. (Reference is given to Appendix A).

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 observed 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.

5.1.8.4 Hydro vs. Wind Production "Average Month each year"

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

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%

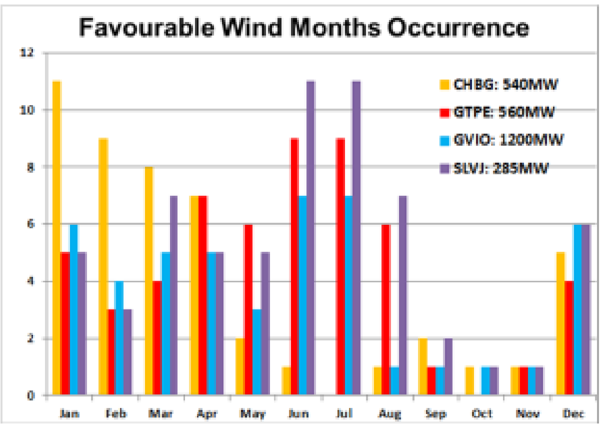
> 40 % Proberbility between Aug 95 - Mar 13
30 -40 % Proberbility between Aug 95 - Mar 13
20 -30 % Proberbility between Aug 95 - Mar 13
< 20 % Proberbility between Aug 95 - Mar 13

It is observed that

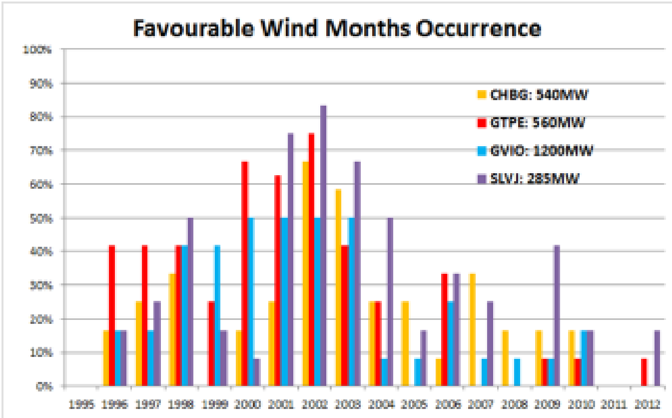
- the occurrence of FWM for CHBG 540MW align very good with the CREG dry months. (The correlation between the hydro inflow and production is good for the 540MW unit).
- June & July months have large FWM occurrence for three units (285MW, 560MW, and 1200MW) where the correlation between hydro inflow and the actual production is poor or inverse.

From the tables in Appendix B 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.

5.1.9 Complementarity -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.

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

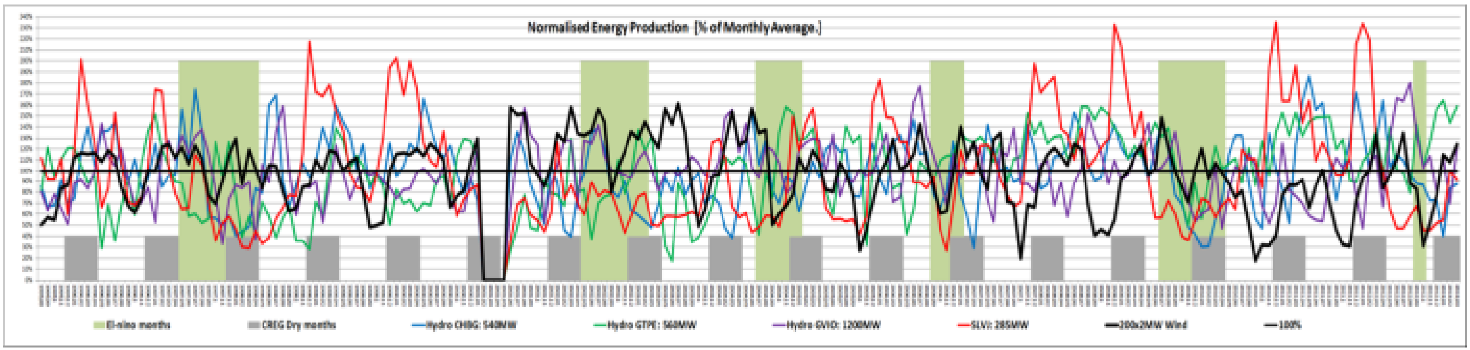
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1983	2,2	1,9	1,5	1,2	0,9	0,6	0,2	-0,2	-0,5	-0,8	-0,9	-0,8
1984	-0,5	-0,3	-0,3	-0,4	-0,5	-0,5	-0,3	-0,2	-0,3	-0,6	-0,9	-1,1
1985	-1	-0,9	-0,7	-0,7	-0,7	-0,6	-0,5	-0,5	-0,5	-0,4	-0,4	-0,4
1986	-0,5	-0,4	-0,2	-0,2	-0,1	0	0,3	0,5	0,7	0,9	1,1	1,2
1987	1,2	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

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.

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

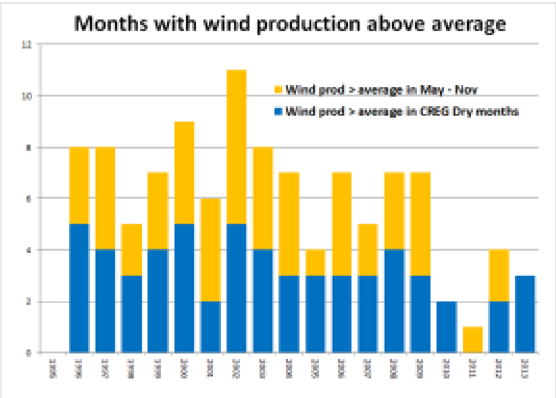
Analysing the hydro vs wind energy production in relation to the occurrence of the El-Niño and CREG dry months takes basis in a time span Nov 00 → Mar 13, using the actual production data for the four selected hydro power plans with unchanged installed capacity for the full timespan.

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 has been analysed and is summarised in the table 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. (Expect 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".

5.2 Analysis of Firm Energy Factor, ENFICC

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).

This study will be based on the method currently adopted by CREG when a reliable 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.

5.2.1 Wind Farms - ENFICC

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 for two time spans

- Jan 83 – Mar 13, 30 year analyse for all wind farms
- Nov 00 – Mar 13, Time span with actual hydro production data available

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

	Jan 83-Mar 13			**Nov 00 – Mar 13**		
Months	All	El-Niño	CREG dry	All	El-Niño	CREG dry
200x2,0MW Wind farm	✚	✚	✚	✚	✚	✚
134x3,0MW Wind farm	✚	✚	✚	✚	✚	✚
15x1,3MW Wind farm (Jepirachi)	✚	✚	✚	✚	✚	✚

The $ENFICC_{95\%}$ calculations are presented in the probability distribution curves "from the lowest to the highest level of firm energy, based on the monthly energy production" are shown in Ref. 9 Study Report 03 Market & Regulatory Aspects for each of above listed scenarios.

The table below summarises the ENFICC calculations implemented for the various scenarios for the Aug 95 – Mar 13 timespan.

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.
  - *$ENFICC_{Base}$*
    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.

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

Further reference is given to study report 03.

5.2.2 Hydro Power Plans – ENFICC

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 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).

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.

5.2.3 Portfolio analysis – ENFICC

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".

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 wind farm and the hydro generator plant.

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 $ENFICC_{95\%}$ 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%

The observations in relation to the $ENFICC_{95\%}$ impact from the different time spans are:

› 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 the El-Niño are compared with "All months".

› Time span CREG dry months only vs. All months
A significant increase of $ENFICC_{95\%}$ (4% .. 11%) is observed when the "CREG dry months" are compared with "All months".

5.2.4 Portfolio ENFICC 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} : $P_{\text{net power for wind farm}}$ [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%	40,0%	11,8%	40,1%	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%	20,6%	30,2%	7,7%	9,6%
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%	40,0%	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 comparing the portfolio with the separate wind or hydro production units.

  - Time span – El-Niño only
    All portfolios (expect 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 comparing the portfolio 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

5.2.5 Conclusions – ENFICC

5.2.5.1 EFICC – 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 draw up:

- The ENFICC calculated for the new and larger wind turbines indicates significant higher figures than CREG assume 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.

5.2.5.2 ENFICC – wind/hydro - portfolio

No clear conclusions can be extracted from the ENFICC simulations implemented.

5.3 Wind Energy Integration Strategies

5.3.1 Key barriers

In addition to the financial aspect 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

5.3.2 Administrative and grid access barriers

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

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 grid connection procedures.

EWEA Recommendations:
- Reduce average grid connection time
- Set and adhere to strict deadlines for administration processes
- Provide well-defined requirements for grid connections and capacities at common coupling points to the public
- Closer collaboration of developer and grid operators

Grid connection costs

Investment risks become high where grid cost information is not well defined or provided early enough in the development process. Different regulations on the share of grid connection costs between system operators and developers, 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
- System operators should adapt costs to the project size
- Better definition (and eventually standardization) of grid codes and connection requirements, which are realistic and correspond with the latest technologies 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.

Physical grid access

In many countries the grid is underdeveloped in windy areas. This causes problems with grid access where developers have to wait longer to get physical connection to the grid. 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 reinforcements and extensions in due time.

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 construct transmission lines interconnecting the wind park to the grid connection point. In many countries a parallel project with environmental impact assessment studies must be established in gaining approval for this transmission line.

5.3.3 System operation including forecasting

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 adapt 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 ensure 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.

6 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

7. Study Report 01: Power System Technical Analysis – Neplan

8. Study Report 02: AEP & Financial Feasibility Analysis

9. Study Report 03: Market & Regulatory Aspects

10. Study Report 04: NEPLAN Training Package

Appendix A Normalised Hydro Production

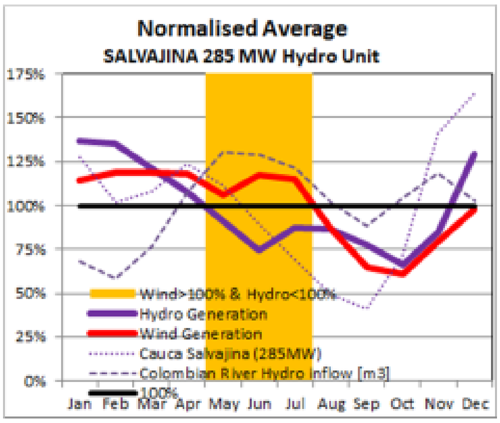
SALVAJINA 285 MW Hydro Generation Unit													Correlation		
Normalised Monthly Average Hydro Production vs. 200 x 2 MW Wind Production												Aug95 - Mar 13	Hydro vs. Wind	Production vs. Inflow	
Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Production	All Rivers	Actual River
Hydro	136,9%	135,0%	121,4%	107,8%	90,7%	74,9%	87,6%	86,5%	77,9%	66,6%	85,3%	129,4%	0,60	-0,09	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			

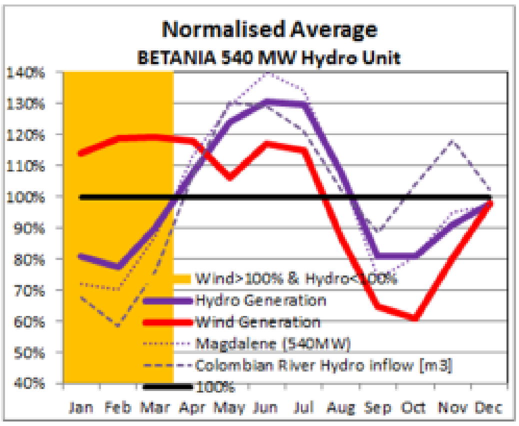
BETANIA 540 MW Hydro Generation Unit													Correlation		
Normalised Monthly Average Hydro Production vs. 200 x 2 MW Wind Production												Aug95 - Mar 13	Hydro vs. Wind	Production vs. Inflow	
Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Production	All Rivers	Actual River
Hydro	80,9%	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			

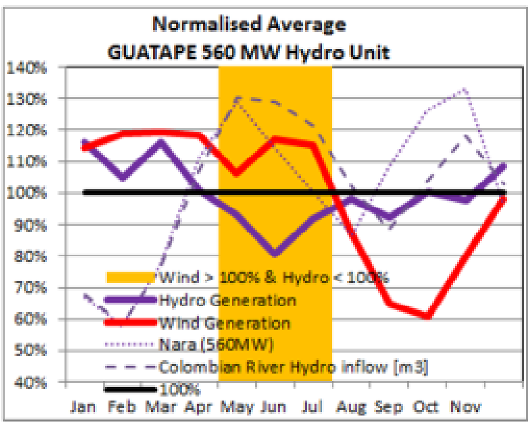
GUATAPE 560 MW Hydro Generation Unit													Correlation		
Normalised Monthly Average Hydro Production vs. 200 x 2 MW Wind Production												Aug95 - Mar 13	Hydro vs. Wind	Production vs. Inflow	
Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Production	All Rivers	Actual River
Hydro	116,4%	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			

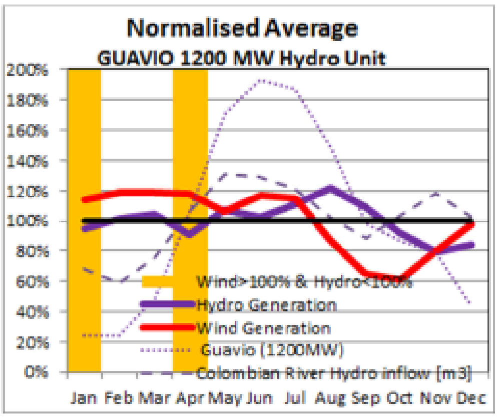
GUAVIO 1200 MW Hydro Generation Unit													Correlation		
Normalised Monthly Average Hydro Production vs. 200 x 2 MW Wind Production												Aug95 - Mar 13	Hydro vs. Wind	Production vs. Inflow	
Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Production	All Rivers	Actual River
Hydro	95,0%	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			

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			









Appendix B 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 C Favourable Wind Months – Graphs