Journal of World Energy Law & Business

Colombia's regulatory and fiscal hydrocarbons regime: explaining Colombia's success and the challenges ahead

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This article deals with Colombia's current fiscal and contractual petroleum regime and how solid institutions have played a role in the country's success in increasing its oil production in a relatively short time. This article also gives an account of some of the challenges that this country will face in the future in order to maintain its position as one of the largest hydrocarbons producers in Latin America.

'*It's very likely that in a couple of years Colombia will surprise the world (. . .and for the record I'm not Colombian myself).*'

Senior Venezuelan geologist deeply involved in Colombia's hydrocarbons industry[1]

1. Introduction

Colombia's success in putting together a transparent and efficient legal, regulatory and contractual hydrocarbons regime in a relatively short timeframe is well known. To many, these changes adopted in 2003 have paved the way for Colombia not only to reverse its declining production trend, but also to increase its petroleum production from 525,000 b/d in 2005 to 955,000[2] b/d in April 2012. As a result of this substantial growth in production, it could be said that Colombia is living a 'production boom'. However, it is important to point out that 90 per cent of the oil and gas produced in Colombia is extracted from mature fields being developed only by Ecopetrol[3] or based on the

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1 From a private exchange with the author.

2 Average for April 2012. It is very likely that Colombian production reached its goal of producing 1 million barrels per day at some point in 2012.

3 Ecopetrol is a semi-public NOC. Colombia owns 88.49% of Ecopetrol's shares.

doi:10.1093/jwelb/jws018 Advance Access publication 16 August 2012

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association systems in force up to 2003. Only 10 per cent are part of the modern concession of the ANH.[4] In total, 58 per cent of Colombia's 2011 average production came from two companies: Ecopetrol and Pacific Rubiales Energy.[5]

Having said that, we believe that the real contribution of the adopted framework will be better understood by analysing the 'exploration activity' and the number of 'ANH Contracts' that have been signed. These contracts make up the backbone of Colombia's surge towards becoming (or maintaining itself) as a significant hydrocarbons producer and increasing its proven reserves. According to ANH records, an average of 21500 Km of 2D seismic equivalent has been shot, and an average of 103 exploratory wells have been drilled in the last four years (2008–2011). This intense drilling activity is also shown in the Baker Hughes Rig Count,[6] which found that Colombia had 63 active rigs in April 2012. To put this into perspective, Peru had five, Ecuador had 17, Argentina had 56, and Venezuela had 75 active rigs in the same month. Without taking into account other variables, it can also be concluded that Colombia is in the middle of a very aggressive exploration campaign, or in other words is living an 'exploration boom'. That this is described as an 'exploration boom' reflects the fact that exploration activities in Colombia and the need for subsequent discoveries are of even more importance than increasing production. Currently, proven reserves in Colombia stand at 2.259 billion barrels with a reserves-to-production ratio of between six and eight years. However, Colombia is regarded as a country with a good geological potential[7] and is largely under-explored.

The success of the current legal, regulatory and contractual hydrocarbons framework resides in the number of companies carrying out exploration activities in Colombia and the foreign investments that are being poured into this sector. In the future, and depending on the exploration success, these contracts are expected to govern a significant portion of Colombia's production.

This article explores only one section of the policy that has put Colombia in the spotlight in terms of international oil investments, and in the path of becoming a hydrocarbons force in the region. We will focus on Colombia's hydrocarbons regulatory agency role and on the analysis of the progressive and flexible 'modern concession' contract and the general fiscal regime applicable to upstream hydrocarbons activities.

2. Background

Due to a short-lived petroleum 'boom and bust' during the late 80s and early 90s, and being on the brink of becoming a net hydrocarbons importer, a comprehensive

[4] Ecopetrol, 'The State Take in Colombia' (2011) 125 Carta Petrolera, availalbe at <http://www.ecopetrol.com.co/especiales/carta_petrolera125/ingles2.htm> (last accessed 8 May 2012).

[5] Author's estimate based on Colombia's Energy Information System *(Produccion Fiscalizada de Petroleo por Empresa Enero-Diciembre 2011)* and Paficic Rubiales Energy 2011 Annual Information Form (http://www.pacificrubiales.com).

[6] Baker Hughes Rig Count, available at <http://investor.shareholder.com/bhi/rig_counts/rc_index.cfm> (last accessed 8 May 2012).

[7] According to the ANH, *P90* Reserves are estimated at 7.4 billion barrels and 14.2 billion barrels for conventional and heavy crude oil, respectively. Colombia is regarded as having a huge unconventional hydrocarbons potential.

hydrocarbons policy was adopted in Colombia during Alvaro Uribe's first presidential term (2002–2006). This policy entailed a complete overhaul of the hydrocarbons framework, including the establishment of a specialized regulatory agency (ANH) and changing Ecopetrol's legal structure[8] in order to make the company more efficient, transparent and competitive. This policy also included the enhancement of security in operational areas through a major offensive against the guerrilla groups operating in Colombia.[9]

This policy also implied changing Colombia's contractual regime to lower the state-take and state intervention in order to attract foreign investments into the hydrocarbons sector. From 1974 until 2003, Colombia experimented with several types of 'association contracts' or joint ventures[10] that, among several other issues, provided for the mandatory 'back-in' participation of Ecopetrol. The approval of the 'modern concession agreement' in 2004 helped to harmonize the regime, thus simplifying its administration for contracts signed *ex-post*. As a result, the State's take under the 'modern concession agreement' plus the current applicable fiscal framework oscillates between 40 per cent and 59 per cent without including the value of the money over time, and between 40 per cent and 64 per cent when deducted at a real rate of 10 per cent.[11]

3. The regulatory agency: *Agencia Nacional de Hidrocarburos*

Creation and responsibilities

The Agencia Nacional de Hidrocarburos (ANH) was created by Law 1760[12] of 26 June 2003, establishing its legal status, responsibilities and structure. This law was amended by Decree 4137 of 30 November 2011, changing the legal status and structure of the ANH, from 'special administrative unit' to 'state agency'. Nevertheless, it is still attached to the Ministry of Mines and Energy. This new legal status confers even more autonomy and responsibilities to the agency. Under the amendment, the ANH keeps its responsibility for administering Colombia's hydrocarbon 'reserves and resources' plus contributing to the promotion of sustainable development of hydrocarbon resources, and contributing to the national energy security. More tangible are the new ANH responsibilities in establishing the crude oil export price for fiscal and currency-exchange purposes and the hydrocarbons price for the royalty valuation and settlement. The amendment also transferred responsibility for administration of the Petroleum Information Bank from the ANH to the Colombian Geological Service.[13]

[8] This was the first step to allowing the offering of part of its shares to the public. This was made possible in 2006 when Ecopetrol's legal structure (to a Mixed Economy Company) was changed by *Law 1118* of December 2006. At the time of writing, two public offers have been made, one in 2007 and the other in 2011.

[9] Nowadays, around 80,000 soldiers are in charge of protecting hydrocarbon facilities in Colombia. On average, one soldier is in charge of protecting almost 12 barrels of oil produced.

[10] 'Association contracts' can be divided into four types. For a detailed description, check JC Echeverry *et al*, 'Oil in Colombia: History, Regulation and Macroeconomic Impact' (2009) Documentos CEDE-Universidad de los Andes.

[11] Ecopetrol (n 4). An ANH presentation at 'IHS Herold Pacesetters Energy Conference 2009' said the State's take oscillates between 40% and 75%.

[12] The same law removed Ecopetrol's regulatory activities and changed its legal status and organic structure. Additionally, it created the company *Sociedad Promotora de Energia, CA*.

[13] The transfer must be made in a period of five years.

These new changes are in line with the amendment of Articles 360 and 361 of the Constitution of 18 July 2011 on 'Royalty Distribution and Compensation Regime' and with Law 1530 of 17 May 2012 enacted on the 'Organization and Operation of the General Royalty System'. These two pieces of legislation are intended to modernize and make more efficient the distribution of royalties among the different recipient entities and projects.

The ANH's administration and direction is the responsibility of the president and the Steering Board. The ANH's president is appointed by the President of the Republic, and the Steering Board consists of the Minister of Energy and Mines, the Minister of the Treasury and Public Credit, and four other public servants, including two representatives of the President of the Republic.

With regards to Colombia's 'liberal fiscal regime'[14] on hydrocarbons, a functional and independent regulatory agency is essential for competent operation. One of the criticisms of this type of regime is that it is not easy to administer, while transaction and 'surveillance' costs are high since the rent-capture mechanisms that come under its remit are relatively complex and variable. In this particular case, the ANH has demonstrated good capabilities in organizing bid rounds, awarding contracts and overseeing operations, as well as creating a progressive exploration and production contract.

ANH Acuerdo N°4 of 2012

On 4 May 2012, the ANH approved the *Acuerdo N°4* (hereinafter *ANH Acuerdo*) on the 'General Criteria for Administration and Award of Hydrocarbons Exploration and Exploitation Areas'. The *ANH Acuerdo*, which is basically a set of regulations, establishes the most important functions of the ANH, including the awards procedure and criteria and the type of hydrocarbons contracts that are available in Colombia.

Contracting procedure: bid rounds and direct awards

According to the *ANH Acuerdo*, as a general rule, contracts must be awarded through a 'competitive process'[15] (ie a bid round) and, exceptionally, through direct awards. From its creation, the ANH has awarded 93 technical evaluation agreements (TEA) and 303 concessions (E&P). The vast majority of these contracts have been awarded through the bid rounds carried out from 2007, when the *Colombia Bid Rounds* system was formally established.[16] The ANH is responsible for organizing and establishing the conditions of the bid rounds. Bid rounds are governed by the *ANH Acuerdo* and by the 'Terms of Reference'[17] that are launched for each of them. The Steering Committee, based on a proposal from the ANH's president, is responsible for the approval of the 'model contracts'.

[14] B Mommer, *Oil Prices and Fiscal Regimes* (OIES 1999).

[15] This can be 'open' or 'closed' (by invitation only). Open bid rounds are more common in Colombia.

[16] Echeverry *et al* (n 10).

[17] The 'Terms of Reference' contain all the information required by companies in order to participate in a bid round. These 'terms' include: qualification criteria, offered areas description, bid parameters (and its evaluation criteria), as well as work and financial commitments.

Type of contracts

The *Acuerdo N°4* established three type of contracts:

- Exploration and production (E&P);
- Technical evaluation; and
- Special.

The E&P contract, on which this article is largely based, confers exclusive rights to the contractor within a delimited area in order to carry out E&P activities at its own risk and cost according to a predefined programme. The contractor is liable for the payment of taxes, royalties and other levies that are explained in this article.

The technical evaluation contract, or TEA under its Spanish acronym, has the objective of evaluating the prospectivity of an area by carrying out technical studies and activities at the contractor's expense and risk under a predefined evaluation programme. The contractor is liable for the payment of a rental fee. These contracts may be converted into an E&P contract according to the specific TEA conditions. Generally, the duration of this type of contract is up to 36 months.

'Special Contracts' are defined as E&P contracts with special or particular provisions with regard to other types of contracts (E&P and TEA contracts). These contracts are approved by the ANH taking into account the specific technological and developmental factors of the hydrocarbons sector.

4. A progressive and flexible fiscal and contractual regime: what makes the Colombian model contract attractive?

A progressive and flexible[18] fiscal system is one that provides the government with an adequate share of economic rent under varying conditions of profitability.[19] This definition matches Colombia's hydrocarbons regime, since it shows flexibility and progressiveness in almost all of its rent-capture mechanisms, including its three most important components: income tax (which is progressive *per se*), royalties, and the right for high oil prices.

We will make some comments on the most important mechanisms in place for the capture of the rent generated by petroleum activities. In order to simplify our study, we have divided these mechanisms into fiscal and contractual. As expected, the analysis is not exhaustive, so it does not cover all the levies that apply to petroleum activities.[20]

[18] 'Progressive' and 'Flexible' are usually used interchangeably.

[19] S Tordo, *Fiscal System for Hydrocarbons. Design Issues*, World Bank Working Paper No 123 (2007) 14.

[20] Such as the Net-Worth Tax *(Impuesto al Patrimonio)* established in 2011.

Fiscal mechanism

Corporate income tax

Hydrocarbon activities in Colombia are not subject to a special corporate income tax (CIT) regime or rate, so they are treated as any other activity liable for the payment of this tax. The CIT is established and regulated by the *Tributary Code (Estatuto Tributario)* and the rate payable for 2012 is 33 per cent. Given the specific nature of hydrocarbons (and mineral) activities, there are special provisions specific to these activities within the taxation framework. It is important to point out that in 2010 the Colombian government introduced several amendments to the *Tributary Code* that greatly affected the hydrocarbons sector. These amendments were contained in *Law N° 1430* of 29 December 2010,[21] repealing many incentives[22] that were very beneficial to the hydrocarbons sector. Among the incentives that were repealed was the special income tax deduction of 30 per cent on tangible fixed-asset investments.

Among the largest petroleum producers in the region, Colombia ranks halfway up the scale in terms of CIT rates.[23] Venezuela, with a special rate of 50 per cent, has the highest CIT for petroleum and non-associated gas activities,[24] followed by Brazil with 34 per cent[25] and Ecuador with 25 per cent.

Royalties

Hydrocarbons royalties were established in *Law 141* of 1994 (as amended by *Law 756* of 2002). The royalty rate for 'conventional' crude oil in Colombia is based on a sliding scale that takes into account the different types of fields and daily production levels.[26] The law establishes a series of discounts relative to 'conventional' crude oil for natural gas, heavy oil and unconventional hydrocarbons. The royalty rate for natural gas produced onshore and offshore up to a water depth of 1,000 feet and heavy oil (<15°API) have a discount of 20 per cent and 25 per cent, respectively. A discount of 40 per cent applies to natural gas produced offshore at water depths greater than 1,000 feet. Also, there is a royalty discount of 40 per cent for unconventional hydrocarbons, which was established in *Law 1530* of 2012. Table 1 shows the royalty rate applicable to the different type of fields in Colombia.

Contractual mechanisms

On 4 July 2004, the ANH released a first model contract, known as the 'modern concession agreement' or 'exploration and production contract'. This contract, which is essentially a royalty/tax agreement, is loaded with progressive fiscal mechanisms that respond

[21] Known as the *Reforma Tributaria 2011*.

[22] Other important amendments included in this law that affect the hydrocarbons sector include changes in the self-withholding tax and its collection and the repealing of the zero-rate VAT for 'intermediate hydrocarbons services' among others.

[23] The author makes this comparison for indicative purposes only. The impact of a CIT is not entirely correlated to its rate but for the combination of its rate, sector-specific incentives and deduction and depreciation rules.

[24] Non-associated gas activities pay the "normal" CIT rate of 34%.

[25] Actually, the CIT tax rate is 15% with a surtax of 10% (on annual taxable profits of more than R$240,000 (*circa* US$120,000 in May 2012) plus a social contribution tax of 9%.

[26] Monthly average.

Table 1. Royalty rates

Fields' Daily Production (BOE)*	'Conventional' Crude Oil Rate	Heavy Crude Oil Rate	Natural Gas Rate for onshore and offshore fields (<1,000 feet)	Natural Gas Rate for unconventional hydrocarbons and offshore fields (>1,000 feet)
0–5,000	8%	6%	6.4%	4.8%
5,000–125,000	8% +(production −5,000) × 0.10	8% +(production −5,000 × 0.10) × 0.75	8% +(production −5,000 × 0.10) × 0.80	8% +(production −5,000 × 0.10) × 0.60
125,000–400,000	20%	15%	16%	12%
400,000–600,000	20% +(production −400,000) × 0.025	20% +(production −400,000 × 0.025) × 0.75	20% +(production −400,000 × 0.025) × 0.80	8% +(production −400,000 × 0.025) × 0.60
More than 600,000	25%	18.75%	20%	15%

* Barrels of Oil Equivalent (BOE) 1 barrel of oil = 5,700 cubic feet of natural gas.

to different oil price conditions and to the quality of oil produced in the relevant area. The original model contract has had some amendments, and the latest model contract[27], issued in May 2012, will be used in the *Colombia Round 2012* that will close in November 2012.

The rent-capture contractual mechanisms are included in the Chapter VI and Annex D of the 'model contract' and are called 'ANH's Contractual Rights'. The basis for the calculation of these mechanisms is updated[28] annually by the ANH. These mechanisms are:

- Rental;
- Right for high oil prices;
- Participation on production;
- Economic rights on production tests;
- Participation on production during the extension of the production phase; and
- Technology transfer.

Rental

Rental, called the 'Right for the Use of the Subsoil' by the model contract, is payable monthly in US$ in all types of areas. However, its calculation varies according to the type of area, as explained below.

[27] The current model contract includes special provisions for non-conventional hydrocarbons.

[28] These values were updated by the *ANH's Circular 01* of 23 January 2012. The update is carried out according to the annual producer's price index variation for finished goods released by the United States' Department of Labour (PPI-Finished Goods WPUSOP 3000).

Table 2. Rental calculation—exploration phase

Size of the area	First 100,000 hectares		Per each additional hectare over 100,000 hectares	
Duration of the phase	≤18 Months	>18 Months	≤18 Months	>18 Months
Onshore areas	2.48	3.30	3.30	4.95
Offshore Areas	0.82			

Exploration areas

In exploration areas, rental is calculated by multiplying the size of the contracted area, measured in hectares, by the values shown in Table 2.

Evaluation and production areas

In evaluation and production areas, rental is calculated by multiplying the contractor's production times US$0.1255 per each barrel of liquid hydrocarbons and US$0.01255 per each 1,000 cubic feet of natural gas. The natural gas production used in re-injection operations or other processes directly related to the same field production are excluded from the rental payment.

ANH participation on production

The ANH Participation in Production (ANH PP) is a payment calculated as a percentage over production from an area in addition to the royalty payment. The ANH PP is used as a main and/or secondary[29] award criterion in bid rounds depending on the type of area.[30] For example, in the Colombia Round 2012,[31] the ANH PP was established as the main or 'primary' bid criterion for Type 1 and 2 areas (including offshore) and an Additional Investment in Exploration Phase 1 was set as the secondary criterion. For Type 3 and unconventional[32] areas, the 'primary' award criterion was the Additional Investment in Exploration Phase 1 and the ANH PP was established as the secondary award criterion. In both cases, the secondary criterion is mandatory.

Right for high oil prices

The ANH is entitled to a payment or 'economic right' for high prices of crude oil when the price of the West Texas Intermediate (WTI) exceeds the price of the

[29] It is taken into account only in the case of a tie in the primary criteria.

[30] Generally, areas are divided into three types in the ANH bid rounds: Mature (Type 1), New Prospectivity (Type 2) and Frontier (Type 3).

[31] This bid round was being launched on 21 February 2012 and is expected to close on 26 November 2012 with the areas award. According to the bid round schedule, the contracts will be signed between November and December 2012.

[32] The *Colombia Round 2012* is offering 115 areas out of which 31 are areas with unconventional hydrocarbons potential. This is the first time in Colombia that unconventional areas are offered within the framework of a bid round. The ANH is requiring more strict qualification criteria for companies interested in these kinds of areas.

base price (Po)[33] which is pegged to different gravities of crude oil and when the field surpasses 5 million barrels of accumulated production, including the volume of royalties. In the case of natural gas, the ANH is entitled to the payment of this right when the price of the US Gulf Coast Henry Hub (Henry Hub) of a 'Po' which is based on the distance from the delivery to the reception point (or destination) and triggers after five years of production. The 'Po' for crude oil and natural gas are contained in Table 3.

The 'grace' volumetric threshold, in the case of crude oil, or period, in the case of natural gas, for the payment of the right to high prices is especially sensible for new contractors since it allows them to recoup part of their initial investment before starting paying this levy.

Only the volumes of natural gas that are exported are subject to the payment of the right for gas prices. It is important to point out that heavy crude oil ($\leq 10^{\circ}$API) is exempted from the payment of this right.

To add even more progressiveness to this levy, its calculation includes a sliding scale with different levels of participation calculated taking into account a correlation between the benchmark (WTI/Henry Hub) and the Po. This sliding scale is contained in Table 4.

The right for high prices is calculated using the following formula:

$$\text{ANH's right for high prices} = \left[\left(\frac{P - Po}{P}\right)\right] \times S$$

where P = WTI/Henry Hub price, Po = Base price according to Table 3 and S = Percentage rate according to Table 4

Economic rights on production tests

The 'model contract' establishes that the liquid hydrocarbons obtained in production tests are liable for the payment of rental, right for high prices and participation on production.

Participation in production during the extension of the production phase

According to *Article 4.2* of the 'model contract' the production period has a duration of 24 years counted from the reception of the declaration of commerciality by the ANH. According to the same provision, the production period may be extended, upon certain conditions that must be fulfilled by the contractor, for successive periods of up to 10 years and up to the economic limit of the field.

If the contract is extended beyond the original production period, the contractor must pay to the ANH an additional participation right on production of 10 percent of the value

[33] The 'Base Price', or Po, is calculated using a formula established in the model contract Annex D (D 2) and updated annually by the ANH. Its latest values are the ones shown in this article and contained in *ANH's Circular 01* of 23 January 2012.

Table 3. Base Price (Po)

Produced liquid hydrocarbons - API gravity	Po (US$/barrel)
$> 29^{\circ}$ API	32.61
$> 22^{\circ}$ API or $\leq 29^{\circ}$	33.87
$> 15^{\circ}$ API or $\leq 22^{\circ}$ API	35.14
$> 10^{\circ}$ API or $\leq 15^{\circ}$	50.18
Discoveries located at a water depth of more than 300 metres	40.15
Exported natural gas- distance in straight line from the delivery point to the receiving point in the destination country in kilometres	**Po (US$/MMBTU)**
≤ 500	7.54
> 500 or	8.79
$> 1{,}000$ or LNG plant	10.04
Unconventional hydrocarbons deposits	**Po (US$/barrel)**
"Rock formations with low primary permeability which must be stimulated to improve mobility and hydrocarbon recovery conditions. Typical Unconventional Deposits include, among others, tight sands and carbonates, methane gas associated with coal seams, gas and oil from shale and bituminous sands"*.	81

**Article 4.41* of ANH's Acuerdo No.04 of 4 May 2012 and *Article 1.57* of the Definitive 2012 Colombia Round Terms of References. It is important to mention that the same *Article 1.57* or the Term of Reference excludes methane gas and bituminous sands from the 2012 Colombia Round.

of 'light'[34] crude oil at the delivery point. For natural gas and heavy crude oil ($\leq 15^{\circ}$API), the ANH has the right of an additional participation of 5 per cent of the production valued at the fiscalization point. Both the royalty percentage and the participation in production can be deducted from the payment of this contractual right.

Technology transfer

The contractor must carry out research, training and education programmes, and support the scholarship programme of the ANH, covering 100 per cent of the cost involved. In the exploration phase (and its extensions, if there are any) the contractor must expend up to 25 per cent of the amount paid as rental.[35] In production areas, the contractor must expend an amount equivalent to 10 per cent of its rental fee.

[34] Even though the 'model contract' made reference only to 'light' oil, we believe that, in fact, this provision also includes medium-gravity crude oil.

[35] See Table 2.

Table 4. WTI/Henry Hub price relative to Po and the participation rate

WTI/Henry Hub price (P)	Participation rate (S), (%)
Po ≤ P < 2Po	30
2Po ≤ P < 3Po	35
3Po ≤ P < 4Po	40
4Po ≤ P < 5Po	45
5Po ≤ P	50

Technology transfer fee cap

In both the exploration phase and production areas, the technology transfer payment must not exceed US$122,875.24[36] per phase or per calendar year, as applicable.

5. Challenges

The first major challenge for Colombia is, without any doubt, increasing its reserves. This challenge may be offset by a big discovery or a string of small- to medium-sized discoveries. The ANH has estimated that in order to double its proven reserves from 2.1 billion barrels to 4 billion barrels by 2020, investments of US$2 billion per year[37] are necessary. To achieve this goal it is essential to have an attractive fiscal regime and strong and stable institutional regime, and Colombia has both. Also, as we pointed out at the beginning of this article, Colombia has a good geology, is largely under-explored, and is living through an 'exploration boom'. Remarkably, Colombia has been successful in attracting qualified professionals[38] to its hydrocarbons industry, many of them former PDVSA[39] workers fired by the Venezuelan president, Hugo Chavez, after the 'petroleum strike' of 2002–2003. Coincidentally, this sad episode in Venezuelan history occurred at the same time as Colombia was restructuring its institutional hydrocarbons framework. Another advantage is that Colombia's most prolific region nowadays *(Llanos Orientales)* has a very similar geology to many Venezuelan[40] fields since it is located in the Orinoco Belt Basin, which, incidentally, is the biggest petroleum basin in the world in terms of reserves. As put by a senior Venezuelan geologist working in Colombia, '*The complexity of*

[36] This value is actually US$100,000 of 2004 constant US$ adjusted to 2012. This value is updated annually by the ANH. The amount showed is the latest updated value by the *ANH's Circular 01* of 23 January 2012. However, *Article 43* of the 2012 Definitive Model Contract establishes that the amount is US$100,000 in constant US$ for 2012 per phase.

[37] Idem *Supra* 11

[38] Pacific Rubiales Energy, a company founded and directed by former-PDVSA high managers is the second largest oil company in Colombia in terms of production and reserves, only after Ecopetrol.

[39] Venezuela's NOC.

[40] As a historical anecdote linking these two countries', oil and fiscal regimes is that after World War I, international oil companies identified Colombia as a much more promising producer than Venezuela. But the enactment of Colombia's *1919 Oil Law* scared many prospective companies away. This left Venezuela in a very good position, 'if it could offer favourable operating terms and the stability needed by the oil companies'. Extracted from B MacBeth, *Juan Vicente Gómez and the Oil Companies in Venezuela, 1908-1935*, Cambridge University Press (1983) 32.

the Andean foothill basin is very similar to Venezuela's North Monagas[41] *fields, that even though partially under-explored, it has had very important discoveries, such as the Cusiana field. The Llanos basin (is geologically) less complex*'. Another challenge is that a big part of the probable reserves in Colombia are heavy or extra heavy oil that, in terms of their development costs (horizontal wells, secondary recovery methods, upgrading, etc.) and lower price in the international market, require the largest reserves and capital investments in order for their production to be economically viable. For this type of crude oil 'economies of scale' plays an important role.

Security is the second major challenge in Colombia. The history of violence in Colombia, dealing with guerrilla groups, paramilitary and drugs cartels, is well known. Security has improved dramatically in the past ten years and the FARC, the largest and most violent guerrilla group, has been dealt many significant blows in recent years. However, the war against these irregular groups is far from over. This violent struggle has a direct impact on hydrocarbons operations and has been partly responsible for the lack of enough exploration activity over several years. Also, major producing areas are far away from the nearest port or refineries so they require an extensive pipeline network, and pipelines are a target of choice in Colombia. Additionally, security is a major problem since many companies operating in Colombia are small-to-medium independents. These companies are not so well suited or don't have enough funds to mitigate this risk. Colombia's biggest challenge in improving security is not only to keep fighting these groups but engage them in credible peace talks and offer real incentives to 'demobilize' guerrilla members.

Crude oil transportation in Colombia is also an issue. An insufficient transportation infrastructure has been a concern and is one of the reasons (the other being security) that Colombia has not reached its goal of producing 1 million barrels per day.[42] The lack of a proper transportation framework has caused bottlenecks and led Colombia's producers to transport a significant amount of crude oil by trucks. However, projects such as the Bicentennial Pipeline[43] will help to solve the problem, although the reality is that if Colombia's ambitious production plans are achieved transportation capacity is likely to be outstripped in the future. De-bottlenecking and upgrading transportation capacity in Colombia is a task that is still awaiting a sustainable solution. In order to address this issue, Ecopetrol announced in mid-June 2012 the creation of Cenit S.A.S a subsidiary specializing in hydrocarbons transportation and logistics.

6. Conclusion

Colombia has one of the most attractive fiscal and contractual regimes in the region coupled with a strong institutional framework. Yet, there are many challenges for Colombia in order to maintain its position as an important producer and as a

[41] For example, El Furrial , a giant field discovered in 1986 with proven reserves of 1.1 billion barrels, is located in North Monagas, Venezuela.

[42] At the time of writing (May 2012).

[43] Phase one is expected to be completed in December 2012.

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'destination' for international oil investments. However, we think that Colombia is on the right path in order to overcome the challenges described above, and many others that have not been analysed in this article. In general, creating institutions in developing countries is not an easy task and the current decade has seen a systematic weakening of institutions in the region. Hence, Colombia's success in creating solid institutions such as the ANH, and strengthening Ecopetrol as a result of the split of its regulatory and operational responsibilities, has been remarkable. Additionally, the fact that Colombia is not an 'oil economy', its economy is balanced, diversified and its oil revenues represent an important, but not a decisive, part of its economy, means that the country is in the best position to be able to maintain a stable and attractive regime. Moreover, the combination of solid institutions, a progressive fiscal regime and the fact that Colombia is not an 'oil economy' all help to shield foreign investors from contract default and expropriation, which are regarded as the most acute forms of political risks. Historically, episodes of expropriation which have characterized the oil sector have been driven by the recurrence of powerful incentives generated by interaction between the structural characteristic of oil development - including oil price cycles - and the presence of a weak and ineffective institutional environment for capturing rents,[44] including the lack of a progressive and applicable fiscal regime.

At a social and indigenous communities' level, Colombia is implementing a break-through royalty-distribution scheme empowering communities from producing and non-producing areas as real stakeholders. So, what Colombia needs now is to keep doing what it has been doing in recent years to maintain the flow of capital into its hydrocarbons industry and sit tight, and hope that this 'exploration boom' translates itself into commercial discoveries.

[44] O Manzano and F Monaldi, 'The Political Economy of Oil Contract Renegotiation in Venezuela' in W Hogan and F Sturzenegger (eds), *The Natural Resources Trap. Private Investment without Public Commitment* (MIT Press 2010).