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THE ROLE OF FOREIGN DIRECT INVESTMENT IN RESOURCE-RICH REGIONS

The Collapse of the Venezuelan Oil Industry: The Role of Above-Ground Risks Limiting FDI

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Introduction

Venezuela offers a striking case-study on the resource curse. The country with one of the largest hydrocarbon endowments in the world has suffered an unprecedented economic collapse, with GDP falling by more than half in five years and inflation topping one million percent. Oil production declined for more than a decade, and more recently, since 2016, it collapsed; this being one of the key drivers of the economic catastrophe facing the country. Production peaked at 3.4 million barrels per day in 1998 and by the end of 2018 it was 1.3 million barrels per day; before US oil sanctions further contributed to additional declines. Shockingly, this happened after receiving the largest resource windfall in the history of Latin America.

There are many elements to this story, but one has to do with the failure to attract foreign investment to the oil industry during the boom times. In the 1990s Venezuela successfully opened up the oil sector to foreign investment, using joint-ventures and service contracts. These investments added more than a million barrels of production capacity and initially compensated the decline in the national oil company's production. But after the investment cycle ended and the oil price boomed, President Hugo Chávez forcefully renegotiated contracts, partly nationalized some oil projects and significantly worsened the investment climate. Instead of an investment boom, as should have occurred with the combination of large reserves and high oil prices; and despite the government actively trying to attract investors and signing multiple deals with companies like Chevron, Eni, CNPC, Rosneft, and Repsol; investment largely did not materialize.

This paper aims to answer two interrelated questions: 1) why did the government expropriate foreign investors, reversing the success of the *Apertura* (oil opening) of the 1990s, and more importantly: 2) why did it fail to attract new investment, despite the favorable geological and price conditions and the many deals it signed with major oil companies? A mix of ideology, weak institutions and structural factors such as high oil prices and the end of a successful investment cycle, help to explain the massive failure to develop the resource endowment of the country, and offer some general lessons for foreign investors and governments.

The paper is organized as follows. Section 2 offers a theoretical framework to understand the relationship between governments and foreign investors, explaining why contract renegotiation and expropriation are so pervasive in developing regions like Latin America. Section 3 briefly discusses the successful *Apertura* of the 1990s. Section 4 analyzes the expropriation that occurred under Hugo Chávez. Section 5 the core of the paper analyzes Chávez's attempts to attract massive new investments in oil and gas, and the failure to do so. Section 6 concludes.

The Political Economy of Oil Investment in Developing Countries

The hydrocarbons sector has some characteristics that can generate substantial above-ground risks: 1) the presence of significant economic rents in oil extraction; 2) the high proportion of sunken costs (immobilized investments), with long maturity; 3) the location of most reserves and investment opportunities in countries which are institutionally weak and subject to high political risks; 4) the significant variation in geological risks, across projects, and during the different stages of investment; 5) the products, gas, or oil derivatives such as gasoline, are consumed widely by the population and represent a significant portion of their basket of consumption; 6) the volatility of oil and, to some degree gas international prices, therefore causing volatility in revenues; and 7) the revenues that are generated are relatively easy to appropriate for the governments (Manzano and Monaldi, 2008; Monaldi, 2019). These traits have very important implications for the development of fiscal frameworks applying to this sector as well as for conflicts between governments, companies, and consumers.

Unlike other industries, petroleum exploitation and, to a lesser degree, gas exploitation generates significant rents. Rents are generally defined as the profit exceeding the opportunity cost of reproducible production factors (labor and capital). For example, in the case of Latin America, the costs of extraction of oil are typically below 15 USD per barrel, but prices have been generally significantly higher. The boom in prices to levels above 100 USD per barrel during the past decade generated exorbitant rents. However, when, in 1998, the price for oil dropped below 10 USD, rents were minimal, and some deposits were even producing without generating any rents or even operating at a loss.

In theory, rents can be easily collected by the government without affecting long-term production. For such purpose, governments can use tools inherently related to their sovereign control over taxes and regulations as well as their property rights over the subsoil. As long as a producer covers its costs and obtains a return that sufficiently compensates the risk, the collection of rents by the State should not provide any obstacle to the development of the potential of the sector. On some occasions, however, oil companies capture a significant part of these rents, whereas in others, States over-extract resources and/or expropriate investors by not permitting them to recover the investment at an attractive rate of return. In the first scenario, the State and its citizens lose financial income, which may be significant, without any ex-post economic justification, though the terms might have seemed to generate a fair split at the time of awarding a concession. In the second scenario, incentives for long-term investment are harmed, and the development of the potential of the sector is affected.

This inability to efficiently capture rents generated through the exploitation of hydrocarbons is partly due to rigid contractual arrangements and the lack of progressiveness of the fiscal systems, under which the government obtains an increase in the collection of taxes which is less than proportional to the increase in international price. This means that, in view of significant increases in the international oil price, governments have incentives to renege on their commitments assumed during periods

with lower price levels. On the other hand, during periods of low prices, the institutional and fiscal frameworks generally make investment hardly attractive (Hogan and Struzenegger, 2010).

The petroleum and gas industry is also characterized by the presence of high sunken costs, i.e. assets which, due to their very nature, are immobilized before companies start recovering their investment. As soon as these assets are tied up, their ex-post value for alternative uses is very low, opening the door for appropriation by the government. The State can forcibly increase its share of revenues and companies would continue to have incentives to continue operating to the extent that they recover operating costs (which are proportionally less). As soon as most of the immobilized investment has been made, the governments will have incentives to expropriate by changing the terms of investment, whether by increasing taxes, regulatory changes, or by unilaterally fixing prices on volumes dedicated to the internal market below opportunity cost – for example, a subsidized price of gasoline or gas. The political benefits of reneging on commitments are high. Over the short term, the government can extract abundant fiscal resources or transfer them to consumers via artificially low prices of the products, without causing any significant impact on production. This logic applies even in the case of state-owned companies.

The exploration and production of oil are particularly risky from a political and regulatory point of view because most of the reserves throughout the world are concentrated in developing countries with weak institutions and subject to high political risks. The governments of these countries have difficulties convincing investors of their capacity to commit and comply with signed agreements in a manner in which both private investors, as well as state companies, can recover their sunken costs. If the political benefits which can be obtained from reneging on agreements are high and the short-term costs of doing so are low, then only the presence of strong domestic institutions or external mechanisms which are capable of enforcing their compliance can ensure the credibility of property rights (Manzano and Monaldi, 2008).

The geologic and economic risk varies significantly among petroleum projects. Depending on the level of these risks and the magnitude of investment in the projects, governments will be more or less willing to invite multinational companies and offer attractive conditions for investment, or not (Nolan and Thurber, 2010). The existence of high geological risks during the stage of oil exploration provides incentives for governments to offer attractive conditions for investors at this stage. However, once exploration is successful, governments start to have incentives for renegotiating the initial conditions.

State companies tend to position themselves in stages and projects with less risk: for example, in areas that have already been developed and which are mature. State companies have less capacity to handle large high-risk projects because, first, they tend to have their reserves concentrated in a single geographic area and, therefore, are less diversified than multinational corporations; and, second, because of the lack of

engineering and/or skilled labor. Likewise, a state as a shareholder tends to be more adverse to assuming very high risks and does not offer incentives for the state manager to assume such risks (Nolan and Thurber, 2010).

In turn, for projects on the technological frontier or in areas with a higher geological risk, large-scale multinational companies tend to be better positioned, for example, in the exploration of new oil provinces, in areas with difficult access (deep-waters), or in the performance of non-conventional crude oil projects (bitumen or shale).

The volatility of international prices of oil means high volatility of revenues. The fiscal systems of the countries in the region have had difficulty collecting the rents generated under different price scenarios, and therefore, price volatility is particularly problematic. In the case of countries that depend on its petroleum and gas exports such as Bolivia, Ecuador and Venezuela, price volatility can cause great macroeconomic and fiscal instability, except where effective stabilization mechanisms have been implemented, which has hardly been common in these countries. Therefore, even though expropriation is more prevalent and generalized during periods of high prices, the governments of hydrocarbon-exporting countries may be tempted to renege on their contractual terms and, in particular, squeeze state companies in case prices are dropping and the government faces a fiscal crisis.

The Cycles of Investment and Expropriation

The aforementioned characteristics of the resource sectors generate the tendency for "expropriation cycles." Governments have incentives to attract investments, particularly in order to reap the future fiscal benefits, but once investments are sunken, they have incentives to renege on the original deal and capture a larger share of the revenues. The short term benefits of expropriation can be high, while its costs, in terms of production decline and foregone revenues, are often paid in the distant future. The mismatch between the political incentives with short term horizons and the investment incentives, with long term horizons, are a source of significant conflict (Manzano and Monaldi 2008; Monaldi, 2019).

The timing of expropriation is highly influenced by the evolution of incentives. When a resource basin has not been developed, and the geology is unknown, expropriation is unlikely. However, after a significant cycle of investment has been completed, adding substantial reserves and production, and the risks significantly decline; the conditions are ripe for expropriation. Similarly, when resource prices go significantly up, and the fiscal and contractual regimes are not able to sufficiently capture the additional rents, there are strong incentives to expropriate. The history of the oil industry in Latin America, other developing regions, and even in some advanced economies, is full of examples of this phenomenon during price booms (Guriev et al., 2011). Rents can also rise due to a decline in costs. Those are less observable than price hikes by the government (they are also less observable by analysists, and thus have been less well studied).

The likelihood of expropriation also varies with other structural characteristics. Countries that are significant net exporters and more fiscally dependent on resource revenues, tend to view the resource sector largely as a source of fiscal rents and are thus more likely to be resource nationalist. Depending on the time horizon of rulers, rent maximization could be short-sighted or have a more long-term perspective. In contrast, in the case of hydrocarbons, net importers are usually more focused on incentivizing production and getting to energy self-sufficiency and therefore are less likely to be resource nationalists.

Institutions and Resource Nationalism

The likelihood of expropriation is also highly contingent on the institutional setting of the resource sector and on the wider political regime. In particular two aspects are especially important: 1) the progressivity of the fiscal and contractual framework, and 2) the political constraints to contractual and fiscal reneging. A progressive system is one in which the government-take increases as the profits from resource extraction increase. The fiscal and contractual regimes in Latin America and many other developing countries have tended to be regressive or mildly progressive. As a result, when prices go up the government-take does not increase proportionally and governments become dissatisfied with their share of profits (Barma et al., 2012).

The wider institutional setting is clearly also relevant. How easy is it for the executive to unilaterally change the government-take? And if it does, which costs it has to face? If the institutional framework generates checks and balances to constrain the executive, expropriation is less likely. For example countries like Brazil, Colombia, and recently Mexico, created autonomous regulatory agencies to govern the hydrocarbons sector. However, as mentioned before, in weak institutional environments with few political constraints external enforcement is typically what provides credibility.

The Venezuelan Apertura (Oil Opening) of the 1990s

Starting in the early 1990s, Venezuela enacted a policy commonly known as the *Apertura Petrolera* (Oil Opening) to attract much-needed investments into the oil industry. Venezuela's oil industry was reserved to the State since the nationalization of 1976 and PDVSA, Venezuela's national oil company (NOC), did not have the resources to increase production in declining fields or to develop the vast extra-heavy oil (EHCO) resources located in the *Faja del Orinoco* (Orinoco Oil Belt – OOB). The *Apertura* opened the Venezuelan oil industry to international oil companies (IOCs) and provided legal and fiscal incentives to attract FDI.

A previous study from Manzano and Monaldi (2010), provides an extensive account of the *Apertura* to foreign investment and the subsequent expropriation under President Hugo Chávez [1]. In this section, we discuss some of its key findings and will focus on the significant, but ultimately failed attempts, by Chávez to attract foreign investment under a new institutional framework.

In the 1990s, the Venezuelan government used three types of contracts to attract IOCs to invest and participate in the oil industry: Operating Service Agreements, Association Agreements, and Risk- Sharing Associations.

Operating Service Agreements (OSAs) were service contracts signed between PDVSA subsidiaries and private investors, mainly IOCs; the latter obtained operational control over the assigned oil fields. PDVSA's subsidiaries received all the output produced by OSAs in exchange for a fee to cover capital expenditures (CAPEX), operating expenses (OPEX) and profits. The goal of this scheme was to attract private investment into mature fields with declining production – so-called marginal fields. A total of 32 OSAs were signed in three rounds between 1992 and 1997. Appendix 2 presents the fields assigned through OSAs. In the first two rounds the contracts were pure service contracts, with no profit sharing, but in the third round were most contracts were awarded, contracts did share some of the risks and profits.

Since OSA operators received a fee per barrel instead of the full oil price, the fiscal regime applied to investors in OSA differed from that applied to PDVSA's subsidiaries. Investors were not subject to royalty – paid by PDVSA instead – and could pay income taxes at the non-oil rate of 34 percent, lower than the 67 percent paid by PDVSA. OSAs, thus, shielded investors from Venezuela's oil fiscal regime. Additionally, since OSA operators were providing a service to one of PDVSA's subsidiaries, the contracts did not have to be reviewed or approved by the Venezuelan Congress.

OSA operators were autonomous, with the capacity of managing daily operations, allocating budgets, hiring staff, and contracting good and service providers. Although, PDVSA had to approve their budgets and development plans.

Association Agreements (AAs) were a second type of contract used. Under this model, PDVSA's subsidiaries could form partnerships with private investors to develop strategic projects as long as the Congress approved the partnership and the State maintained some form of control. Through AAs, PDVSA formed joint ventures (JVs) with IOCs to develop resources different from conventional oil: extra-heavy crude oil in the OOB and non-associated offshore gas fields. These resources required large investments for which PDVSA did not have the required resources or technical expertise, and wanted to share some of the risks. The Venezuelan Government and Congress approved five AAs with IOCs between 1993 and 2001 (Appendix 3).[2]

As the JVs created through AAs were meant to carry upstream activities, they had to comply with the fiscal regime applicable to oil activities. The low-prices environment and the high development costs threatened the profitability of the projects, PDVSA agreed contractually to reduce the royalty rate from 16.67 percent to 1 percent – with a provision to restore it to 16.7 percent after a certain number of years or revenue goals were achieved. Additionally, the Venezuelan Congress approved a reform to the Income Tax law to reduce the rate paid by the AAs from the oil rate of 67 percent to the regular rate of 34 percent.

All AA contracts included a PDVSA subsidiary as a partner to satisfy the state control requirement by the Supreme Court. The creation of a partnership indicated that PDVSA subsidiaries and investors jointly managed and operated the projects, with a control committee. Although the investors had majority stakes by investors, PDVSA maintained a golden share with some veto rights. All AAs directly managed the oil commercialization, without having PDVSA as an intermediary. This was an important guarantee of cash flow control. The projects were also generally partly funded with project finance, which was

The final contractual mechanism was the Risk-Sharing Contracts (RSCs). These contracts allowed investors to explore for new reserves and, if successful, produce oil under a joint venture with a PDVSA subsidiary. In a potential JV, PDVSA could have a participation no larger than 35 percent. Eight REs were awarded through an auction in 1996 (Appendix 4).

The fiscal terms applicable to RSCs consisted of a royalty calculated using a scale between 1 percent and 16.67 percent – depending on the project's internal rate of return. The income tax rate was 67 percent, and bidders offered an additional participation on profits (PEG) up to 50 percent. Investors were responsible for conducting exploratory activities and complying with a minimal exploratory program; the State did not guarantee the presence of reserves.

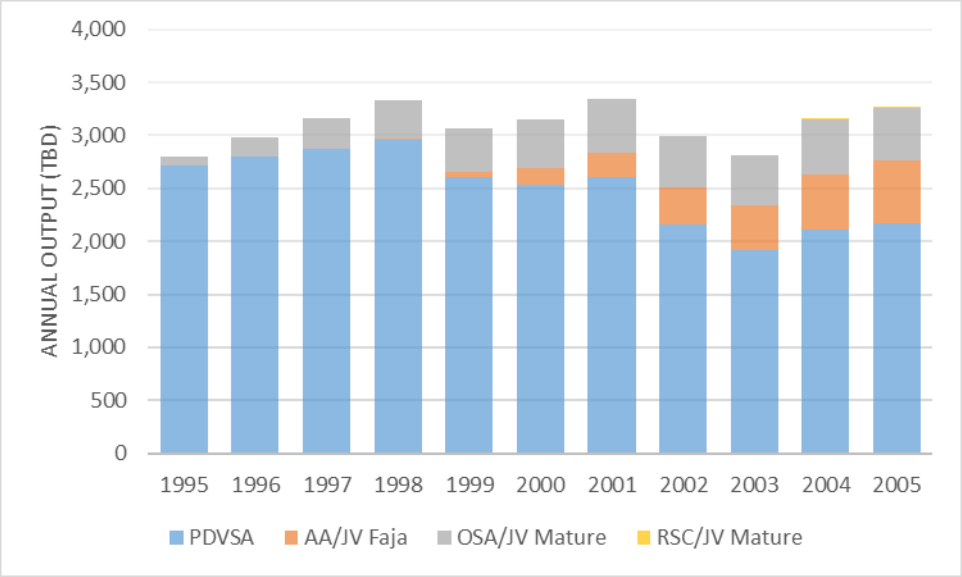
All three contractual models were based on Article 5 of the 1975 Oil Nationalization Law allowing for service contracts to outsource activities by PDVSA or its subsidiaries, as well as joint ventures to develop strategic projects approved by Congress. It is important to highlight that, as Manzano and Monaldi (2008) argue, Article 5 only provided a narrow scope for the *Apertura* contracts and had to be expanded by favorable interpretations by the Venezuelan Supreme Court in 1990 and, later, in 1996. The terms and conditions for the operation of OSAs, AAs, and REs, were established contractually between IOCs and PDVSA's subsidiaries.

A common element across all *Apertura* contracts was the existence of clauses providing contractual stability and protecting the investors. If the Venezuelan government decided to unilaterally change the contractual terms, PDVSA had to compensate the partners. In addition, contracts were afforded protections granted by some Bilateral Investment Treaties (BIT) that Venezuela signed, e.g. with The Netherlands. Contracts included access to international arbitration to resolve investment disputes. PDVSA and its international assets served as a guarantee, increasing the economic cost of a future renegotiation (Monaldi, 2008; Pate, 2009; Manzano and Monaldi, 2010).[3]

The *Apertura* was a great success. Almost all the major international oil companies in the world invested in Venezuela. BP, CNPC, Conoco, Chevron, ENI, Exxon, Petrobras, Repsol, Shell, Statoil, Total, among others, made significant investments. In 2005, combined output from OSAs and AAs reached an average of 1.1 MBD. Projects developed during Apertura added an output capacity of 1.2 MBD. Rystad Energy

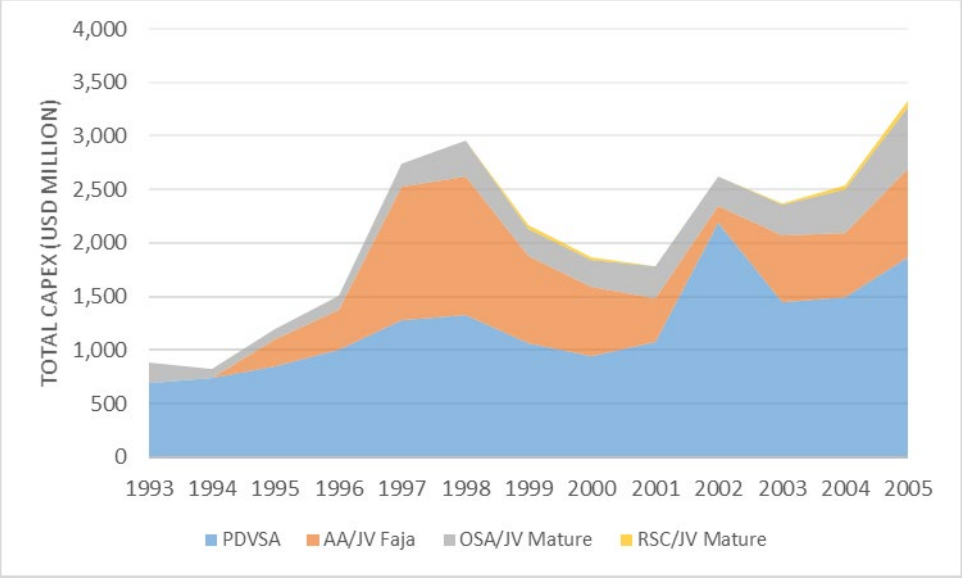
estimates the CAPEX provided by private investors at USD 10.8 billion. Manzano and Monaldi (2008) estimated that the total CAPEX on the *Apertura* projects at $25 billion.

Figure 1: Venezuela's Oil Output



Sources: Petroleum Ministry Statistical Bulletin (PODE), Rystad Energy UCube, OPEC Monthly Oil Report, own calculations.

Figure 2: CAPEX Estimations



Sources: Rystad Energy UCube, own calculations.

Hugo Chávez, the Oil Price Boom and the Expropriation of the Oil Sector

Hugo Chávez won the Venezuelan presidency in 1998 on an anti-establishment platform. He vowed to review the oil policy that enabled the *Apertura* and increase control over PDVSA and the oil industry.[4] But, at the same time, Chávez signaled that his government would respect the existing oil contracts,[5] a message later emphasized by Alí Rodríguez[6] – one of Chávez' main collaborators and, later, petroleum minister.

Moreover, during his inaugural year, Chávez signed Venezuela's first Gaseous Hydrocarbons Organic Law (GHOL), liberalizing the natural gas sector. This law created a separated legal and fiscal framework for non-associated gas activities. Most notably, the GHOL allowed private companies to participate in any upstream or downstream activity without the direct State participation. Investors could maintain full ownership and operations in non-associated gas projects. The GHOL also set a 20 percent royalty rate. The GHOL was generally well-received by investors and started new auction processes for onshore and offshore exploration licenses.

The first step to reform the institutional framework of the oil industry came in 2001 with the approval of the Hydrocarbons Organic Law (HOL). The new law explicitly allowed for private investments across all oil activities, except for upstream activities where investors could only participate through JVs where PDVSA has a majority stake (*Empresas Mixtas*). This was a mechanism to maintain a leading role for PDVSA in all new projects with private investors. Additionally, only PDVSA could commercialize and export crude oil – refined products or upgraded oil could be exported by private companies. The HOL also established that any dispute between investors and the government had to settle based on domestic laws and through domestic courts, discarding the possibility of international arbitration.

In fiscal terms, the HOL raised the royalty rate from 16.67 percent to 30 percent, allowing for a lower 16.67 percent rate for bitumen projects. A separate reform of the Income Tax Law reduced the rate paid by oil companies to 50 percent to balance the impact of the increased royalty; the maximum income tax for independent downstream activities was set to the non-oil rate of 34 percent. Besides the royalty and income tax, the law created three new taxes:

- *Superficial tax:* set as an annual payment of 100 tax units (TUs) per square kilometer not exploited. This tax increases each year by 2 percent during the first five years and by 5 percent thereafter.
- *Own consumption tax:* defined as 10 percent of the value of each cubic meter (m3) of hydrocarbons produced and consumed as fuel in operations.
- *General consumption tax:* paid by final consumers in the domestic market and set annually by the national budget law. The tax must be set at a rate between 30 and 50 percent of the product's price.

While the new law supported the participation of private investors, it created a more limited role for investors than the *Apertura* contracts had provided. It also limited the applicability of international arbitration. However, the government initially insisted that the Law would not apply retroactively to existing contracts.

In 2005, by the end of the investment cycle created by the *Apertura*, the Venezuelan government unveiled a new investment plan for the oil and gas industry, known as the Plan Siembra Petrolera (PSP).[7] This plan indicated the main investment projects for PDVSA and for private investors, mainly in the following areas:

- Certification of Orinoco Belt reserves.
- New greenfield projects in the Orinoco Oil Belt (OOB).
- New projects in conventional oil fields.
- Non-associated offshore gas: Deltana Platform, Mariscal Sucre, and Rafael Urdaneta projects.
- Construction of new refineries.
- Diversification of export markets.
- Development of new infrastructure.

The PSP defined two periods with specific output goals: 2005-2012 and 2012-2030. For 2012, the government set output targets of 5.8 MBD of crude oil and 11.5 BCFD of natural gas. Additional targets included a refining capacity of 4.1 MBD and total exports of 4.7 MBD. The PSP planned that PDVSA would lead the output growth, almost doubling the crude oil production to 4 MBD. The government, however, expected new projects with private investors within the goals of PSP to generate additional crude oil output of 0.7 MBD, both through new joint ventures in the OOB and existing RS projects.[8] PDVSA estimated the cost of PSP at USD 77 Billion between 2005 and 2012. It also expected to provide 70 percent of the expected CAPEX, while private investors would provide the remainder.

The Expropriation of the Apertura Contracts

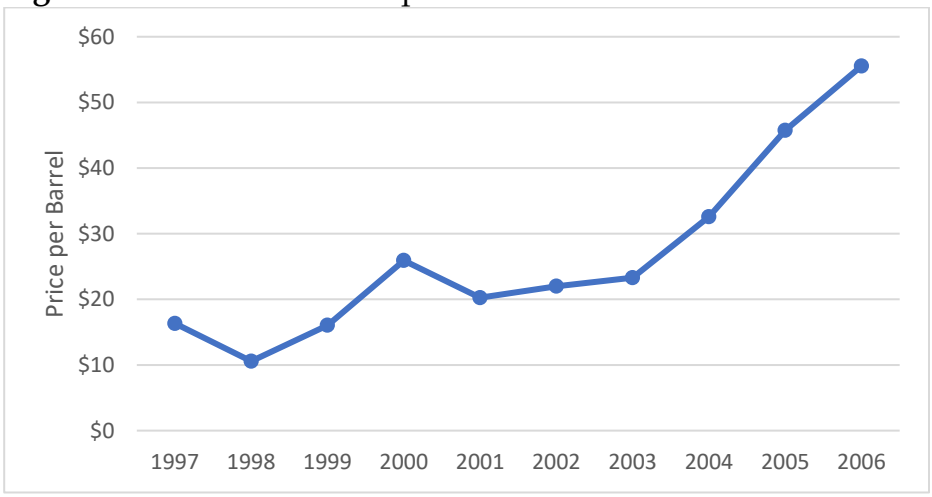
In late 2004, almost five years after Hugo Chávez came into power, the government announced, for the first time, changes in the contracts of the Apertura. It started with an

Brief chronology of the expropriation process:

- 2004 – Royalty increase for the Orinoco Oil Belt (OOB) to 16.67 percent
- 2005 – Income tax increases for OSA and AA.
- 2006 – Extraction tax: 1/3 of the value of all hydrocarbons produced, deducting royalty payments. This tax effectively increased the royalty rate to 33.3%, mainly affecting the OOB projects that payed 16.67% royalty.
- 2006 – Illegality of OSA contracts and migration to JVs.
- 2007 – Forced migration of AA and RSA to JVs.
- 2008 -- Windfall tax

increase of the royalty from 1 percent to 16.67 percent before the contracts' triggers had been reached. It continued with the claim that OSAs owed back taxes. Then it moved on tax and royalty changes to the new laws. Finally, it resulted in the forceful contract renegotiation and partial nationalization of all *Apertura* contracts. Companies that did not accept the terms like Exxon and Conoco were fully nationalized with offers of book value compensation, well below market value. Overall it resulted in a significant increase in the government-take and state control over operations, as well as a reduction in privately operated oil production and reserves. Venezuela's expropriation led the way in a wave of resource nationalism in Latin America that continued in Bolivia, Ecuador, and Argentina, and had some milder manifestations in Brazil.

Figure 3: Venezuelan Oil Export Prices



Source: Petroleum Ministry Statistical Bulletin (PODE)

Table 1: Largest E&P Companies by Output

Company	2005 Output
Chevron	161.72
ConocoPhillips	129.62
Total	107.98
Eni	61.93
BP	57.59
Exxon Mobil	53.52
Shell	46.57
Petrobras	45.19
Repsol	42.09
Equinor	30.78

Company	2007 Output
Chevron	89.78
Total	49.41
BP	23.34
CNPC	15.88
Equinor	15.77
Shell	14.05
Petrobras	14.03
Repsol	12.72
Anadarko	6.91
Harvest	5.18

Source: Petroleum Ministry Statistical Bulletin (PODE), own calculations

Why did it take Hugo Chávez 5 years to start the expropriation process? A few developments made it much more attractive and feasible. 1) The end of the investment cycle meant that all projects had deployed their sunken investments. 2) The price of oil significantly increased in the context of contracts that were fiscally regressive, i.e. as profits grew the government-take declined. International arbitration acted as a weak deterrent in the context of massive short term benefits from expropriation. 3) Chávez took full control of the formerly autonomous national oil company and used to lead the expropriation effort. However, once Chávez and his team realized that they need to generate a new investment cycle they started to design a negotiate a series of new projects, prioritizing the participation of national oil companies from allied countries like China, Russia, and Iran, but also including most of the major international oil companies that were operating in the country. Conoco and Exxon were not invited because they were in litigation with the government over their expropriation, but all the other companies were in play.

The New Deals with Foreign Companies and the Continued Deterioration of the Investment Climate

The government's ambitions to increase production, in the context of the new framework provided by the forced migration to the new Joint Venture contracts and the new fiscal rules, generated the need for new projects, particularly to develop resources in the Orinoco Oil Belt. The approach, however, was different from the one used in the 1990s. New players were invited, with a much larger role for National Oil Companies from allied countries, building a closer link between political alliances and business relationships. This led to different types of deals, where the discretionary allocation of production blocks became part of the new strategy for the Chávez administration.

As Kaplan and Penfold (2019) point, the oil and sector was one of Chávez's instruments to build support from non-Western state actors, and respond to U.S. influence in Latin America. The emergence of China and India as growing centers for oil (and energy) demand and Russia's renewed interest in Latin America provided the opportunities for Venezuela to diversify the origin of their foreign investments.

China

In the case of China, the sustained period of economic growth that started in the 1990s led to an increase in oil consumption, to the point of becoming the largest crude oil importer worldwide in 2016, revealing its high exposure to foreign imports. By launching its "Going Out" policy in the early 2000s, which promoted overseas investment by Chinese companies, the government was trying to increase their access to natural resources, and pay more attention to energy security concerns.

At the same time, China started to extend loans to countries in Latin America, for projects that included the expansion of infrastructure (e.g. electricity and transport facilities), and the development of manufacturing. Joint funds and credit facilities also

sought to facilitate the acquisition of Chinese goods, some of them directly related to oil operations.[9] Loans to Venezuela are paid with crude oil and products, relying on a scenario in which PDVSA could at least sustain its production. The expectation was to create conditions to foster the development of critical sectors and provide opportunities for Chinese state-owned companies to enter the oil and gas sector in Venezuela, securing access to energy resources. The energy cooperation guidelines were established initially in 2001,[10] which signaled the intention of helping companies such as CNPC, Sinopec, and CNOOC, to get involved in Venezuela, as well as the objective of securing export markets in China.

Among the Chinese companies, CNPC ended up with -by far- the largest presence in Venezuela. Their main equity interest is in the JV Petrolera Sinovensa, which originally was an Orimulsion project,[11] and later became a project for blending extra-heavy grades with lighter crudes.

Chinese investments in Venezuela have been criticized by the opacity of the contracts related to the investment in the JVs, as well as the financing agreements for increasing oil production.[12] Moreover, authors such as Kaplan and Penfold (2019) argue that meeting debt commitments of oil-backed loans reduces PDVSA's cash flow generation capacity, constraining its ability to fund investments and impacting oil production. The result is that Venezuela effectively became even more dependent on Chinese financing. Some other concerns were related to the relationship with local workers, and protests arising from problems with working conditions.[13]

Russia

Unlike China, in the case of Russia, geopolitical motivations took more relevance, over business interests, as the involvement in Venezuela grew stronger. Even though Vladimir Putin's administration had specific goals of building relationships overseas for the promotion of strategic industries such as the energy sector and armaments, the rise to power of friendly left-wing governments in Latin America allowed Russia to pose a challenge to U.S. supremacy in the hemisphere.[14]

This two-fold strategy had some implications for the oil and gas sector in Venezuela. At the beginning of the 2000s, companies such as Gazprom, Rosneft, Lukoil, Surgutneftegaz, and TNK-BP expressed interest in Venezuela. In 2006, Gazprom was allocated a block for exploration in Venezuela's waters. However, eventually, Rosneft became the key Russian player, not only becoming the largest holder of reserves in the country but also signing financing agreements to be paid in oil, as in the Chinese case. Another reason for Rosneft's interest in Venezuela was the acquisition of natural gas projects.[15]

Other Actors from the "Oil Diplomacy"

As part of its strategy of leveraging on the oil and gas sector and its revenues to advance in its foreign policy ambitions, the Chávez administration signed several

energy agreements and cooperation mechanisms,[16] intended to attract new partnerships with NOCs from several countries. In South America, as part of energy security deals, Venezuela granted Argentina, Uruguay, and Paraguay participation in the "South American Block" of the Orinoco Oil Belt.[17] Other examples included the creation of Joint Ventures with companies from Cuba (Vencupet) and Belarus (Petrolera Bielovenezolana) for the development of gas projects in Anzoategui. The JV Bielovenezolana was assigned two producing blocks in the Maracaibo Lake area, Guara Este and Lago Medio X, and was later awarded three additional mature blocks in the Orinoco Basin.

Similar to China, India experienced a dramatic increase in oil imports at the beginning of the 21st century. Between 2005 and 2013, this country increased its imports from 1.93 to 3.88 MBD, becoming the third-largest crude oil importer. Energy security concerns also drove companies to look for new sources of supply, including for the increasing demand coming from refineries capable of processing heavy crude oil.[18] Indian national oil companies signed some oil production deals with Venezuela.

IOCs

Most major players with broad international experience, such as Chevron, Total, Shell, Eni, and Repsol stayed in Venezuela after the forced migration to JVs and nationalizations of 2006/2007. After the exit of Exxon and ConocoPhillips, BP sold its position in Venezuela in 2010 for US$ 1.8 to TNK-BP, which eventually would become part of Rosneft.

US-based Chevron has been active in Venezuela since the 1920s and is the largest private oil producer in Venezuela. It has a presence in Western areas (Maracaibo Lake), the Orinoco Oil Belt, and has a position in offshore gas assets, with an interest in moving forward with a project to send gas to Trinidad. Its strategy has adapted to changes in the regulatory environment and also proposing changes on it whenever possible to make investments attractive.[19]

[Total has had operations since 1980] and has equity stakes in PetroCedeño, one of the former association agreements producing and upgrading EHCO in the Orinoco Belt. It also has a presence in Yucal Placer, where its production goes to the domestic market, as well as some presence in offshore exploration blocks. Part of the potential success for the company in Venezuela relies on the country's ability to turn into a gas exporter, which would bring a different set of challenges.

Other European companies that participate in oil and gas activities are Repsol, Eni, and Equinor (all three with assets in offshore gas and in the Orinoco Oil Belt) and Perenco (conventional oil).

Main Initiatives and New Contracts after the Nationalizations

The Oil Sowing Plan

The "Plan Siembra Petrolera" (PSP – Oil Sowing Plan) contained Venezuela's oil and gas policy guidelines from 2005 to 2030. The Venezuelan government has frequently revised the PSP, but it usually includes the ambitious development of the OOB, expansion of oil and gas production, massive CAPEX requirements mostly funded by PDVSA, and exports market diversification with a focus on China and India. Initially, PDVSA prepared a strategy for the 2005-2012 period aimed at increasing crude oil production to 5.84 MBD. This strategy contemplated a phase of certification of reserves (Magna Reserve Project), development of OOB, exploitation of the country's gas potential and the expansion of oil infrastructure in general, together with building additional refining capacity. Some authors argue that Venezuela's push for massive investments in the OOB reflected both the operating infrastructure deficiencies, as well as other strategic goals like employment promotion and migration towards more economically depressed areas.[20]

The HOL allowed the government to select partners in JVs either through competitive bidding rounds or through a direct assignment with the approval of the Council of Ministers.[21] The Carabobo auction was the first process using competitive bidding to select investors in the OOB's Carabobo Area. Additionally, the Venezuelan government also relied on direct negotiations to select investors from countries considered political allies.[22] Many new partners, however, did not have the relevant experience or technical expertise required and probably could only have a financing role. As the process of awarding areas moved forward, assurances were made that companies would have "all guarantees for their investments." [23]

The Magna Reserva Project

Magna Reserva was a project to quantify and certify commercial reserves in the OOB.[24] The Petroleum Ministry divided the OOB into 36 blocks within four large areas (Boyacá, Junin, Ayacucho, and Carabobo),[25] and invited investors to jointly explore and certify the presence of reserves. The Venezuelan government assigned most of the blocks to foreign national oil companies (NOCs),[26] many from countries with political alliances with the Chávez administration. Investors signed MOUs with the Petroleum Ministry to study development plans for the fields. According to government reports, 28 companies participated in 32 blocks and "incorporated additional reserves" of 220 billion barrels of oil. In practice what they did was certify resources (oil in place).

The Carabobo Auction

In 2008, following the 2006/2007 expropriation process, Venezuela launched the Carabobo auction for three fields with original oil in place (OOIP) estimated in more than 500 billion barrels.[27] Since these resources were composed of heavy and extra-heavy crude oil, large investments were required for extraction and processing facilities,

including upgraders. Venezuela expected each field to produce up to 400 KBD of upgraded crude oil.[28] Nineteen companies participated in the auction, and winners were selected by a formula based on a signing bonus, a marketing proposal for the heavy crude oil produced, and a funding proposal to reduce PDVSA's financial burden. Later, PDVSA specifically asked for a minimum of USD 2.5 billion signing bonus and USD 3 billion of loan guarantees to fund PDVSA's CAPEX share.[29]

The Carabobo auction suffered several delays due to the bidding conditions and the 2009 global economic crisis. Initial tender conditions proved too restrictive and inflexible for bidders and, after two proposals in November 2008 and May 2009, no company made a bid.[30] Cárdenas García (2011) identifies four elements of inflexibility in the tender package:

- *Fiscal regime*: The Venezuelan government insisted on maintaining a 50 percent income tax, a 33 percent royalty, a windfall profits tax, plus the requirement that partners needed to secure 100 percent of project financing, including PDVSA's share of CAPEX in each project.
- *Technical factors*: Investors considered that a 20 percent recovery factor for projects in the OOB – as required by the government – was much higher than what was commercially achievable for the type of crude located in the area. This would imply even larger investments and costs than what was originally expected.
- *Operating factors*: Investors were not willing to provide funding, but have PDVSA maintain full operational control of the projects. They will take all the project risk and have little control.
- *Exclusion of arbitration clauses in contracts for primary activities:* Investors insisted on having access to international arbitration given recent expropriation events in Venezuela; government officials soon rejected that possibility. In that sense, both NOCs and IOCs looked at alternative methods to protect their contracts. Bilateral Investment Treaties (BIT) between Venezuela and other countries were considered to be that alternative, not only for IOCs but even for countries such as Belarus, Vietnam, and Russia.

In response to the lack of interest in the first two proposals, the Petroleum Ministry announced two possible fiscal incentives based on the HOL to ensure the economic viability of projects: reducing royalty and the extraction tax to 20 percent, and waiving payments of the general consumption tax. Additional incentives included the possibility of reducing the income tax to 34 percent if partners built a refinery for the extracted crude – instead of an upgrader and an extension of the upgrader construction period.[31]

In February 2010, the Venezuelan government awarded the Carabobo 1 block to a consortium led by Repsol, also including Malaysia's Petronas and three state-owned Indian companies: ONGC, Oil Indian Limited, and Indian Oil Corporation.[32] A consortium led by Chevron, with the Japanese companies Mitsubishi and Inpex, and

Venezuelan Suelopetrol, won the Carabobo 3 block. The composition of the winning consortia revealed complementarities: while the NOCs provide political and financial capital, the IOCs offered technical expertise.

The Carabobo 2 block received no bids and the government initially announced it would award the block to PDVSA, but in 2012 PDVSA decided to develop the area jointly with Russia's Rosneft; the latter offered a signing bonus of USD 1.1 billion and a USD 1.5 billion loan to finance PDVSA's CAPEX.[33]

An analysis by IHS summarizes the final conditions for the winners. The Repsol-led consortium offered a USD 1 billion signature bonus for Carabobo 1, while the Chevron-led consortium offered USD $500 million for Carabobo 3. The government accepted to receive the value of the signing bonus in six installments as the project reached certain milestones. Both groups offered a USD 1 billion loan guarantee to finance PDVSA's CAPEX share and the resolution related to disputes over this financing are subject to the Laws of the State of New York. The Petroleum Ministry could reduce the royalty and taxes to make the projects financially viable. The timeline to build the upgraders was extended from 48 to 84 months and international partners could directly manage its construction; once the upgrader was finished PDVSA would take over. JVs could produce a blended crude during an "early stage" to fund the construction of the upgraders.[34] As for the concerns about international arbitration, Repsol found protection under the Venezuela-Spain BIT and Chevron through a Danish subsidiary, under the Venezuela-Denmark BIT, which include arbitration clauses.[35]

Initially, the Venezuelan government forecasted that the Carabobo 1 block could reach a production target of 400 KBD, once the construction of the upgraders was finished. Similarly, the original plan contemplated a production target for Carabobo 3 of 480 KBD.[36] PDVSA's President estimated that CAPEX for developing the two blocks could reach USD 30 billion.[37]

Direct Allocations in the Junín Area

The Venezuelan government also directly negotiated with countries such as Russia, China, and Vietnam to develop resources in OOB's Junín area. This direct award of blocks to NOCs, without a transparent auction, was seen as a discretionary practice that generally intended to favor political allies.[38] As a result, four projects were awarded, which are summarized in Table 2[39]:

Table 2: Junín New Projects

Project	Partners Equity Shares	Target Production (KBD)	Investment (Bn. $)
Junin Block 2	PDVSA 60 % Petrovietnam 40%	200	11.4
Junin Block 4	PDVSA 60% CNPC 40%	400	16.3
Junin Block 5	PDVSA 60% ENI 40%	240	18.7
Junin Block 6	PDVSA 60% Russian Consortium 40%	450	> 10

Operational conditions for these projects varied, providing preferential conditions for some of the partners, as in the case of Russia and Vietnam. Some of these incentives included the following: [40]

- *Corporate governance provisions:* The vote of qualified majority gave the foreign partner greater control over the business and budget plans.
- *Adjusting mechanism and incentives:* The Venezuelan government approved incentives to assure the economic profitability of the projects and the investment recovery within a specific timeframe. These incentives included reductions in royalties and extraction taxes and the possibility of early production (to generate cash flow before the construction of the upgraders). The bilateral agreements established incentives aimed at achieving an Internal Rate of Return (IRR) of 19 percent.
- *Separate taxation for upstream and downstream:* Income taxes would be 34 percent instead of 50 percent for businesses focused on downstream activities, or refining, allowing JVs to separate their upstream and downstream projects.
- *Arbitration and BITs:* BITs with Vietnam and Russia included the possibility of international arbitration in the case of expropriation. Moreover, the BIT with Russia included specific considerations on how the investor's compensation in such an event. This is revealing as even countries such as Russia, with possible leverage on the Venezuelan government, looked for protection against the erratic and discretionary policies of Chávez administration.

New JVs in Mature Fields/Orinoco

The government also discretionarily "directly" selected partners for mature fields in new JVs formed since 2007. Table 3 summarizes the new JVs created by the Venezuelan government.

Table 3: New Mature Field JVs

Joint Ventures	Partners	Year
Petrozumano	PDVSA 60% CNPC 40%	2007
Petrolera Bielovenezolana	PDVSA 60% Belarusneft 40%	2007
Petrolera Indovenezolana	PDVSA 60% ONGC 40%	2008
Petrolera Vencupet	PDVSA 60% CUPET 40%	2010
Petrozamora	PDVSA 60% GPB Global Res. 40%	2012
Petrourdaneta	PDVSA 60% Odebrecht 40%	2012
Petrolera Venangocupet	PDVSA 60% Sonangol 20% CUPET 20%	2013

- Petrozumano was formed in 2007, following several years of negotiations between Venezuela and China, to exploit the mature fields in the eastern Zumano area.

CNPC bought its participation with "vouchers" it received from PDVSA in 2006.[41] The average output reached 2.3 KBD between 2007 and 2014.

- Belorusneft and PDVSA formed the JV Petrolera Bielovenezolana in 2007 to exploit mature fields. It has gained the rights to develop 13 oil and natural gas fields between 2007 and 2010.
- In 2008, PDVSA and ONGC Videsh Limited formed Petrolera IndoVenezolana to exploit the San Cristóbal field in the OOB region. ONGC planned to invest USD 354 million to increase production from 20 TBD to 40 TBD.[42]
- In December 2010, Venezuela's National Assembly approved a JV with Angola's Sonangol and Cuban oil company Cupet SA to operate the Miga and Melones oil fields, with an output target of 20 TBD.[43] It is worth noting that it was only in June 2013 that the JV was officially authorized to start operations.[44]

Non-Associated Gas Projects

The Petroleum Ministry has completed several rounds of licensing bids for non-associated gas fields since the 1999 GHOL was enacted. In 2001, six onshore areas were awarded to foreign and local investors.[45] In 2003 and 2004, the Petroleum Ministry conducted two auctions for offshore blocks in the Deltana Platform, in the border region with Trinidad & Tobago, awarding three blocks to Chevron and Statoil (now Equinor). The Petroleum Ministry conducted two additional rounds of offshore blocks in Western Venezuela in 2005, awarding five blocks.[46] Appendix 8 presents a summary of all non-associated gas blocks.

In parallel to the new auctions, PDVSA maintained negotiations with partners to develop the Mariscal Sucre project (formerly Cristobal Colon).[47] Following several renegotiations and restructurings of the original project, in 2005 PDVSA decided to start developing the fields on its own.[48] Rosneft has shown interest in participating in the Mariscal Sucre project since 2013 when it signed an MOU with PDVSA.[49] The Petroleum Ministry finally awarded Rosneft with a 30-year license to develop the Patao and Mejillones fields in December 2017.[50]

Table 4: Signed LNG Project agreements

Project	Partners	Gas Source	Capacity	Year
LNG I	PDVSA 60% Galp Energia 15% Chevron 10% Qatar Petroleum 10% Mitsubishi 2.5% Mitsui 2.5%	Deltana Platform, blocks 2 and 3	4.7 MTA	2013
LNG II	PDVSA 60% Galp Energia 15% Enarsa 10% Itochu 10% Mitsubishi 2.5% Mitsui 2.5%	Mariscal Sucre	4.7 MTA	2013
LNG III	PDVSA 60% Gazprom 15% ENI 10% Petronas 10% EDP 5%	Mariscal Sucre	TBD	2016

The non-associated gas projects were expected to bring new natural gas volumes both for domestic consumption and for exports. The Petroleum Ministry expected 1,470 MCFD of natural gas from projects in the Deltana Platform, 1,000 MCFD from blocks in Rafael Urdaneta, and 1,200 MCFD from Mariscal Sucre project.[51] The additional natural gas output would also support exports through both an interconnection with Colombia and LNG trains in Eastern Venezuela. In 2008, Venezuela signed MOUs with international investors to build and operate three liquefaction plants (Table 4). None of these has advanced any further.

Shifting Positions, Heterogeneous Actors and Starting Conditions

As illustrated in the awards for the OOB, mature fields, and gas fields, the Venezuelan government attempted to use oil and gas resources to achieve political and economic goals. As proposed contractual conditions proved to be too tough, companies (and governments) developed different strategies to be able to participate in these new projects. IOCs partnered with international NOC partners who provided sources of finance, political leverage, and political risk mitigation. NOCs used instruments like BITs or energy agreements to get investor protection and more flexibility in the contract terms. These characteristics resulted in diverse (and often opaque) contractual conditions, which served as a sign of the uncertainty in the future management of the projects.

Business Conditions and the Operational Environment

As international investors signed new deals that would mean sinking many billions of dollars in Venezuela's oil industry, they faced deteriorating business conditions and a worsening operational environment. Almost all the new oil projects involved low geological risk because the fields were already producing oil (in the case of mature fields), or the areas had been well explored for decades (like the OOB fields). Only the offshore fields had some relevant geological risks. Most of the risks that investors faced were above-ground: an increasing government-take, PDVSA's control over operations, a distorted foreign exchange regime, an overall discretionary legal framework, widespread corruption, and more recently theft. This section details how a deteriorating business environment increased the risk for international investors to the point that it hampered the new projects' advance, despite the highly advantageous price conditions and prolific geological endowment. These risks were particularly relevant given the recent expropriations and history or contract reneging in the country.

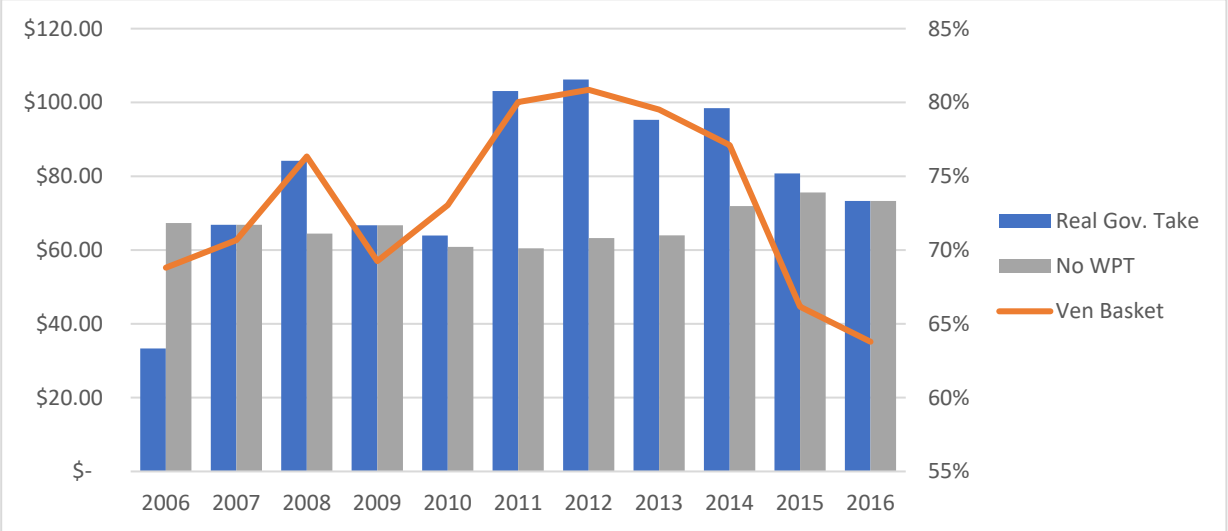
Additional Taxes and Higher Government Take

Outside the scope of the HOL, the most significant tax change in Venezuela was the Windfall Profits Tax (WPT)[52]. The Venezuelan government enacted the new WPT responding to the rapid increase in oil prices during 2007 and 2008. As international prices rose above a certain threshold, marginal rates became higher. In its first version, in any month when the average oil price[53] rose above 70 USD/B all exported oil had to

pay a "special contribution" equal to 50 percent of the difference between the actual price of the Brent and 70. If the average monthly price rose above 80 USD/B, the special contribution was 60 percent. A 2011 reform set the special contribution for extraordinary oil prices at a rate of 20 percent of the difference between the average monthly oil price and the oil price established in the annual budget law for the respective fiscal year.[54] The reform also defined a category of "exorbitant prices" with higher rates: 80 percent, 90 percent, and 95 percent for prices above 70 USD/B, 90 USD/B and 100 USD/B, respectively. To avoid a marginal tax rate higher than 100 percent, the 2011 reform capped the application of the regular 30percent royalty to a maximum price of 70 USD/B.[55]

Both PDVSA and the JVs were subject to the WPT. Figure 4 compares Venezuela's real government take with an alternative scenario without a WPT,[56] showing the biggest impact between 2011 and 2012 when prices were above 100 USD/B. Without the WPT, the government-take would have been between 70 and 71 percent, instead of 81 and 82 percent. The Venezuelan government usually deliberately underestimated the oil price in the budget-law approved by the National Assembly (with government majority), allowing the Chávez administration to increase taxes just by lowering the oil price assumption for the fiscal year[57]. This provided a significant discretionary tax authority over the oil industry which could be, and was, used opportunistically.

Figure 4: Government Take and WPT



Source: PDVSA Financial Statements 2006-2016, own calculations.

The Petroleum Ministry also had total discretion to issue WPT waivers through the lifetime of investment projects, in the following cases:

i. New fields developments or projects that increased output, as long as they have not recovered their investments; and
ii. Crude exports within international cooperation or financing agreements.[58]

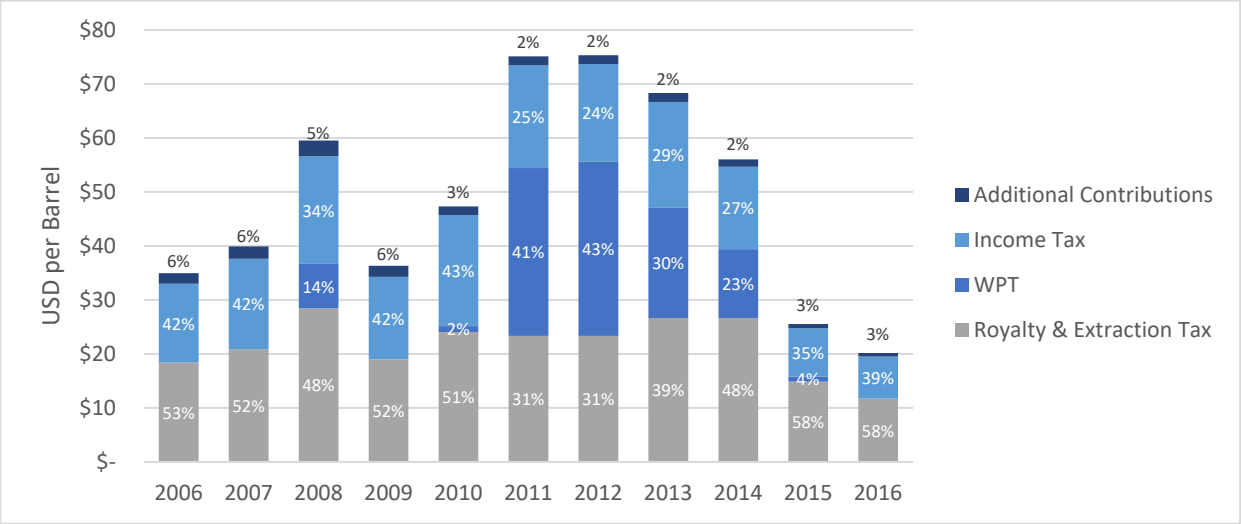
The WPT Law instructed the Petroleum Ministry to prepare the parameters used to determine when investments are recovered. The terms in the 2011 Law gave ample space for the Petroleum Ministry to grant and/or terminate the WPT waivers, with little transparency for investors. In 2013, the government reformed the WPT law and the conditions to apply for waivers, directing the Petroleum Ministry to establish the specific parameters to calculate the exempted crude oil volumes. To the best of our knowledge, the Petroleum Ministry has not yet published these parameters. Additionally, both versions of the WPT law allowed the Executive to grant WPT exemptions to certain exports based on Venezuela's economic and foreign policy objectives. Given this uncertainty, even if the objective of the WPT waivers and exonerations was to provide economic incentives to new investments, the vague language raised additional concerns for companies.[59]

While the WPT was the most significant change in the fiscal regime, the Venezuelan government also created general taxes and contributions that affected JVs. The Law of Science and Technology (LOCTI), first enacted in 2005, created an obligation to invest 2 percent of annual gross revenues on science and technology projects.[60] A 2010 reform to the LOCTI law replaced the investment obligation with an annual contribution of 0.5 percent of JVs' gross revenues to the National Fund for Science, Technology, and Innovation (FONACIT).[61] Other contributions included:

- Anti-drug contribution (2010): a special contribution of 1 percent of annual operating income to the National Anti-Drug Fund (FONA).[62]
- National Sports Fund contribution (2011): a special contribution of 1 percent of annual net income to the National Fund for Development of Sports, Physical Activities and Physical Education.[63]
- Social development contributions: a special contribution of 1 percent of net profits before taxes to develop social investment plans, subject to national government's approval.[64]

As seen in Figure 5, WPT payments represented about 35 percent of all taxes paid by PDVSA and JVs between 2011 and 2013.[65] The introduction of the WPT reduced the share of taxes coming from corporate income taxes during the period of high oil prices (from being between 34 percent and 43 percent in the period 2006-2010, to being between 24 percent and 29 percent in the period 2011-2014). As the oil prices decreased, the contribution coming from royalties increased to 58 percent of total fiscal contributions from the oil industry (considered in the budget) during 2015-2016.

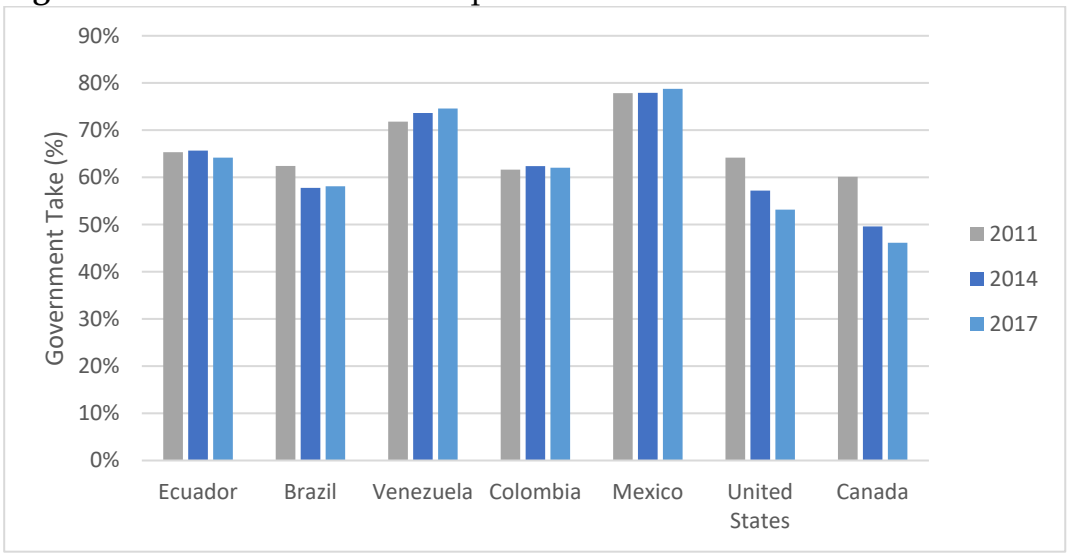
Figure 5: Oil Taxes Allocation



Sources: PDVSA Financial statements (2006-2016), own calculations.

Considering all taxes and contributions paid for oil producers, Venezuela has had one of the highest government-takes in the region. Using estimations of discounted cash flow at a 10 percent rate,[66] Venezuela receives 75 percent of oil revenues through taxes, second only to Mexico's 79 percent (Figure 6). Investors in Venezuela frequently highlight the government-take as a concern,[67] not only due to its impact on profitability but due to the unpredictability of changes in the fiscal regime. Given the high risks of opportunistic expropriation of profits in high sunken investment projects, as explained in the theoretical part, a highly discretionary fiscal framework is a significant deterrent for investment. However, this has not been the only challenge for foreign companies operating in the country.

Figure 6: Government Take Comparison



Source: Rystad Energy UCube, own calculations

The Operation of the JVs

According to the HOL, the JVs terms and conditions approved by the legislature, and the model contract; each JV must act as the operator of the field designated by the Petroleum Ministry. This means that JVs should make their own operational decisions based on existing regulations and agreements between partners. In reality, investors quickly realized that PDVSA, the majority shareholder, considered JVs as subsidiaries instead of independent operators.

Multiple reports have indicated investors' concerns about PDVSA's relation with JVs, mainly related to PDVSA's management disregard for partners' know-how and expertise. PDVSA often took decisions affecting JVs without enough considerations for its partners.[68] A 2014 study commissioned by PDVSA to the British firm Bell Pottinger revealed that one of the main concerns by investors was the PDVSA did not see investors as business partners but as adversaries.[69] PDVSA's top management often threatened to deny dividend payments or invalidate the JVs unless partners managed to increase output.[70]

Investors also had concerns about PDVSA's increasingly politicized role. Throughout the Chávez administration – especially since the 2002-2003 oil strike – PDVSA became the equivalent of a Ministry to execute and fund the government's social and development policies.[71] PDVSA was no longer just an oil corporation, but it also devoted resources and staff to implement several social programs in areas such as health, education, housing, infrastructure, and social welfare.[72] PDVSA also assumed an openly partisan position, with former PDVSA President and Petroleum Ministry once declaring in a leaked video that "PDVSA is red, red from top to bottom",[73] indicating political support for Chávez's socialist party, which characteristically used the color red. Partners were concerned about political interference in their operations, with reports indicating that PDVSA often directed staff to be absent from the operation in order to attend political rallies.[74]

As PDVSA maintained a majority stake in all joint ventures, PDVSA centralized almost all operations and decisions. According to bylaws, a board with proportional representation of all partners managed the JV. This structured ensured that PDVSA would always have the majority of votes in board meetings. The President – directly appointed by PDVSA – chaired the board in each JV. Additionally, PDVSA had the exclusive right to nominate the General Manager, who was responsible for day-to-day operations; the PDVSA-controlled board had the responsibility to approve the General Manager appointment. Private partners had the right to appoint operation managers according to their participation in the JV.[75] Appointing managers, however, failed to provide significant influence to private partners, since the General Manager often made the final decisions. Only in the case of the JV Petrourica, with the Chinese CNPC, did the partner had the right to appoint a Deputy General Manager who oversaw operations during the development phase of the project.[76] This managerial structure

maintained PDVSA-appointees in key decision-making positions, resulting in stronger control over daily operations.

PDVSA also exerted control over JVs through its cash-flow management. Both the HOL and the JVs' terms and conditions required most JVs to sell all their "natural hydrocarbons" output exclusively to PDVSA,[77] using a price formula based on international benchmarks. Only the three Orinoco Belt JVs with active upgraders – Petropiar (Chevron), Petrocedeño (Total and Statoil), and Petromonagas (Rosneft) – could directly export their output since they produced a "synthetic crude" through the upgrade process.[78] As the sole buyer of all the output from most JVs, and based on the original contracts, PDVSA had to make timely payments for the oil and gas volumes delivered. This arrangement meant that each JV and private partner is exposed to PDVSA's commercial risk. In fact, after the 2008 and 2009 fall in oil prices, PDVSA frequently delayed payments to JVs causing cash shortages and delays in payments to contractors.[79] In some cases, contractors and providers accumulated arrears for several years before receiving payments.[80]

PDVSA's poor cash-flow management frequently caused delays for the successful development of investment plans. First, payment delays affected contractors and service providers, with many either increasing prices to compensate for the additional risks or refusing to work at all.[81] Second, cash-flow problems also delayed dividend payments to partners, the only way that partners can receive revenues from JVs.[82] PDVSA does not publicly disclose the outstanding debt to JVs, but it is reported that in 2013 the debt to JV partners reached USD 2.5 billion. [83] These issues increased the cost to develop investment projects and reduced the partners' willingness to support the JVs investment plans. As would be expected, JV partners often deferred final investment decisions causing delays in the development plans.[84] In other cases, partners such as Sinopec initiated a lawsuit against PDVSA for failing to honor payments for procured goods, which eventually was settled.[85]

In an effort to solve the cash flow issues with JVs and to allow PDVSA to cover its cash calls on investment, the NOC negotiated with private investors to find alternative financing mechanisms. Between 2013 and 2016, PDVSA signed eight financial agreements with partners in JVs to support investment plans and increase output (Table 5). Through these agreements, the JVs were to receive about USD 10.7 billion in loans to maintain operations and support investment plans.

The main feature of these financial agreements is the creation of an offshore trust that collects all the proceeds from the oil produced by the JV and pays contractors, payroll, taxes, loan repayments, and dividends to partners.[86] The financial agreements, essentially, mitigate the financial risk for JVs by creating a mechanism that isolated the JVs' revenues from PDVSA's cash flow management. Investors also gained additional control over the project's operations.[87] Despite the benefits presented by this alternative financial mechanism, it is worth noting that PDVSA only allowed these agreements in exchange for loans that covered the JVs expenditures and reduced the financial pressure

over PDVSA. Not all partners in JVs were willing to comply with these conditions and only eight JVs, out of 31 JVs facing the same cash-flow issues, successfully reached an agreement with PDVSA.

Table 5: JV Financial Agreements

Joint Venture	Partners	Size of Loan (US$ MM)	Year	Initial output (KBD)	Target output (KBD)
Petroboscan	Chevron	2,000	2013	104	127
Sinovensa	CNPC	4,015	2013	140	330
Petrozamora	GPB Global Res.	1,000	2013	70	104
Petrowarao	Perenco	420	2014	6	24
Petrocabimas	Suelopetrol	625	2014	26	57
Petroquiriquire	Repsol	1,200	2014	50	60
Indovenezolana	ONGC	318	2016	20	40
Petrodelta	CT Energy PFC Oil & Gas	1,130	2016	40	110

Procurement management also generated additional risks for investors in JVs. PDVSA controlled most procurement and contracting processes in the JVs through two mechanisms: JVs' board of directors and the contracting delegation mechanism (NAAF).[88] First, according to bylaws, contracts required the approval of the JV's PDVSA-controlled board of directors, indicating that partners required the explicit approval from PDVSA representatives to execute any contracting process.[89] Second, PDVSA created an internal control system called NAAF in order to oversee the contracting processes of its subsidiaries and JVs.[90] Through NAAF, PDVSA's Executive Committee[91] defined the financial authorization levels at each subsidiary and JV limiting their ability to sign contracts to only those with amounts below the NAAF limits. This internal control process led to many contracts needing PDVSA's approval since they exceeded the NAAF-defined amounts. Executives in JVs often needed to persuade PDVSA's top managers for them to approve contracts necessary for daily operations, causing delays and increased costs.[92] In other cases, partners also faced risks when failing to comply with PDVSA's directives in procurement. In April 2018 two Chevron executives were arrested facing "possible treason charges for refusing to sign a parts contract for a joint venture with PDVSA", according to press reports, quoting sources.[93]

The Venezuelan government's 2009 decision to expropriate over 60 service contractors compounded the challenges to procure the services needed for daily operations. This decision was the result of a months-long dispute between PDVSA and oil service companies demanding payments for their services. Several companies had threatened to suspend operations until they received payments for past invoices.[94] Many of them were also seen as aligned with the opposition governor of the Zulia State. The May 2009 Law that Reserves to Venezuela the Assets and Services Related to Primary

Hydrocarbons Activities allowed the government to take over the assets of companies providing water and gas injection, gas compression, and services associated with the Maracaibo Lake.[95] The services that JVs used to obtain through private contractors had to be now contracted to PDVSA or its subsidiaries – providing PDVSA with additional control over the JVs' operations.[96]

PDVSA's operational control over JVs also included human resource management. JV partners have reported that PDVSA often hired new personnel without their approval, leading to bloated payrolls and higher costs.[97] The use of employment as a source of patronage by government officials was an increasingly worrisome issue. According to PDVSA's annual reports, between 2009 and 2016 the staff in JVs almost quadrupled from 10,515 to 37,162 people, while output grew by 47 percent from 0.74 MBD to 1.09 MBD. It is worth noting that during the same period, PDVSA upstream staff contracted from 44,727 to 33,986 people, as production declined.[98]

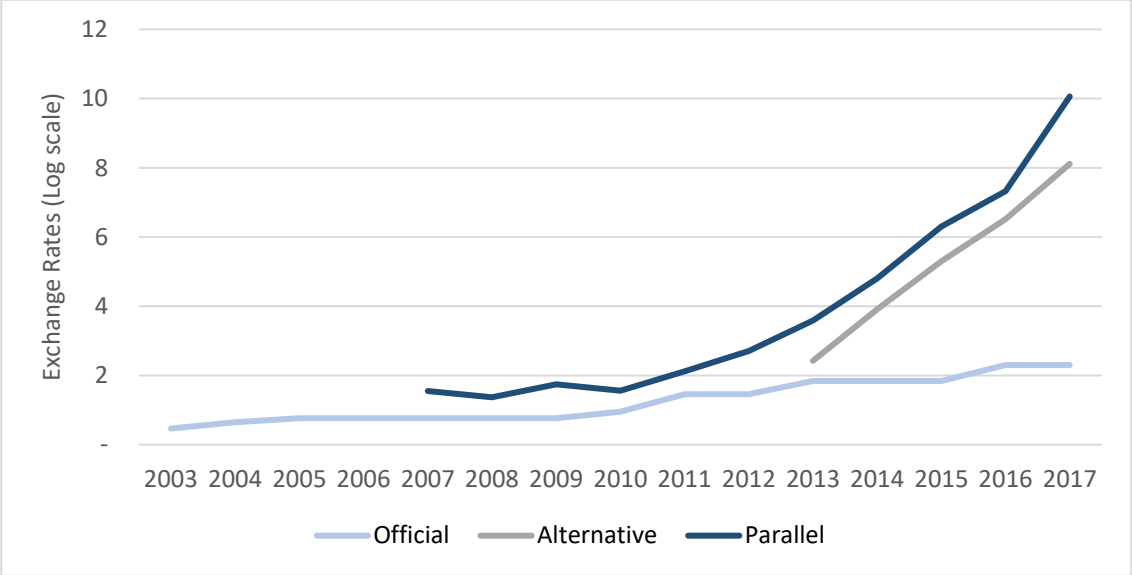
PDVSA's increasing control on JVs' resulted in worsening efficiency indicators for JVs. Rigs' non-productive time was on average 40 percent in 2015, above global standards by between 10 percent and 15 percent.[99] Partners in JVs have reported that completing a well may take up to four months when an efficient drilling crew should do the same job in half the time.[100] Lower efficiency and longer times have increased production costs, affecting the profitability of investment projects and reducing partners' incentives to support large investments in Venezuela.[101]

FX Regime and Domestic Inflation

The Venezuelan government maintains foreign exchange control policies since 2003, regulating the quantities of foreign currency that companies could exchange for domestic currency and defining an official exchange rate (sometimes one rate, other multiple official rates).[102] The rates were adjusted infrequently which, combined with increasing domestic inflation, led to an appreciation of the real exchange rate.[103] Oil exporters – PDVSA and JVs – have to sell the foreign currency generated from oil exports, at one of the official fixed rates, to the Venezuelan Central Bank (BCV).[104] Since JVs contractually received their revenues in USD, the regulation and the lack of adjustment in the exchange rate led to increasing costs to cover their share of domestic expenditures.[105]

The effects of this distortion on costs increased as inflation in Venezuela accelerated, particularly after 2013. Estimations on OPEX for a single mature field project can vary between 5.5 USD/B and 17 USD/B just by using a different exchange rate.[106] A report by Platts quotes an official in a JV indicating that "daily routine operational activities cost twice what they were budgeted, affecting the earnings of each partner company."[107] The Central Bank introduced alternative FX systems, starting in 2013, looking to mitigate the problems on companies' cost structure.

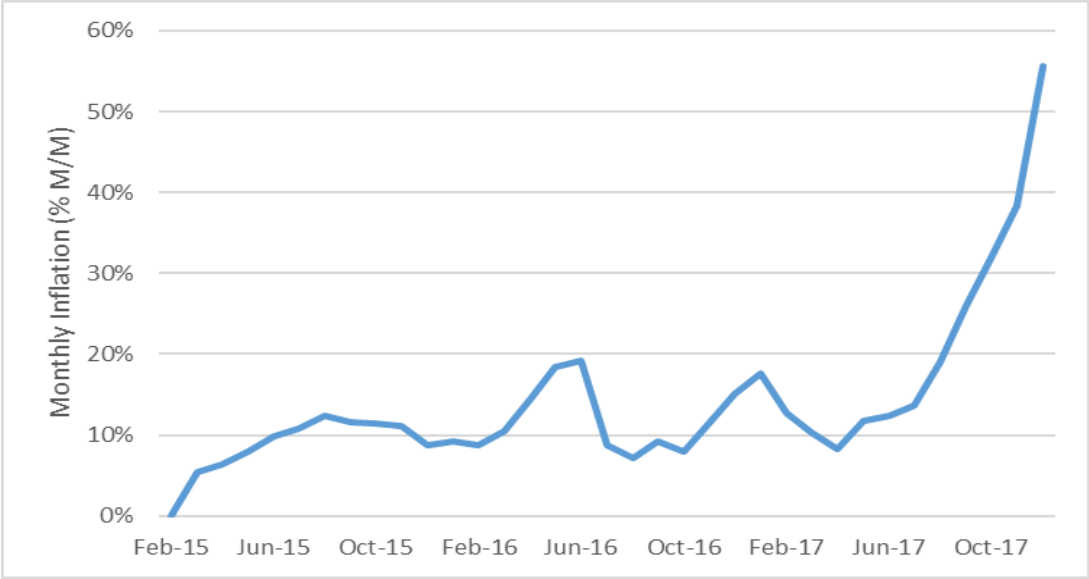
Figure 7: Venezuela Multiple Exchange Rates



Source: Venezuelan Central Bank (BCV), The Economist Intelligence Unit 5-year forecasts, and own calculations.

However, as Figure 7 shows, even this rate was lower than estimates of the parallel, black market, or unofficial exchange rates[108], used by many suppliers in Venezuela to adjust their prices in local currency. Moreover, as the economic crisis in the country deepened and the aggressive expansion of money supply[109] (mostly coming from Central Bank loans to PDVSA) boomed, distortions became even worse as the country entered into hyperinflation (Figure 8).

Figure 8: Domestic Inflation



Source: Venezuelan Central Bank, own calculations.

Besides the effect of currency appreciation on domestic costs, investors faced the uncertainty of which rate they could use to obtain the domestic currency (bolivars), in this multiple exchange rate system.[110] The national government could modify at any time the exchange rates and the conditions allowing JVs to access alternative FX systems. This legal and regulatory framework gave the government significant leverage to modify the profitability of investment projects and pressure to investors in JVs. It could implicitly represent a higher government-take or a way to subsidize Venezuelan constituents at the expense of investors. For example, former Petroleum Minister Rafael Ramirez declared in 2013 that through the alternative FX systems "oil investments made in Venezuela will have an exchange rate above the controlled exchange rate of Bs 6.30 per dollar," adding that "this is an exchange incentive for companies to bring their dollars to Venezuela."[111] Following this policy, only the JVs that agreed to arrange financial agreements (Table 5) could access the higher alternative rates.

In 2016, the Central Bank established that all proceeds from PDVSA and JVs could be exchanged at any of the valid rates: either the DIPRO rate of 10 Bs/USD or the DICOM rate that was closer to 600 BS/USD.[112] The decision on which rate would be used fell on the Economy Vice-President, the Minister of Finance, and the BCV. This new rule applied even for the proceeds generated from the financial agreements mentioned before. This gave the central government total discretion on the exchange rate each JVs would use, a significant risk for investors given that the alternative rate was 335 times higher than the official rate by 2017. Even though Venezuelan government officials presented it as an incentive to JV's foreign investors[113], the announcements also lacked credibility. This is because the multiple rates provided arbitrage opportunities to those actors able to buy dollars at the lower DIPRO rate, which would force eventually PDVSA or JVs to sell at that lower rate. The lack of foreign currency supply for the system, given lower USD cash flow for PDVSA amid the economic crisis and increasing debt service[114], meant that the exchange rate would have to adjust more frequently to avoid further distortion in costs.

Discretionary Legal Framework

One of the main features of the current legal framework is that most of the terms affecting investors stem from laws, in contrast with the *Apertura* period when individual contracts defined such terms. A law-based framework can support FDI by providing transparency, legal security, and potentially increasing the political costs of renegotiations.[115] Venezuela's legal framework, however, failed to provide legal security to investors and, instead, created additional political risks that may have curbed investors' interest and FDI. Based on existing laws, the Venezuelan government could take unilateral decisions with a significant impact on the profitability of the investment projects outlined in the PSP; those decisions could also be easily reversed.

An example of the power shift in favor of the government was found in Article 24 of the 2001 HOL. Based on the law, the rights to carry "primary" (i.e. upstream) activities are granted by a presidential decree. The HOL also allows the government to withdraw the

rights to produce oil from any JV "whenever the operators (JVs) fail to comply with their obligations in a way that impedes the objectives for which such rights were transferred."[116] Neither the law or the JVs' terms and conditions define the circumstances under which production rights can be withdrawn, providing ample space to interpret when the JVs have failed to fulfill their objectives. The rights to grant or withdraw production rights gives the government significant leverage to negotiate, or renegotiate, contracts with investors, preventing a stable legal framework.[117]

The transfer of participation by JVs' partners was another example of a lack of constraints for the government in exercising its authority over the oil and gas sector. The JVs' terms and conditions, contracts, and bylaws indicate that partners can only transfer their equity with the approval from the Petroleum Ministry, with a few exceptions.[118] In other words, whenever a partner in a JV wants to withdraw from the project, selling its equity participation or contract, it needs to request approval from the Petroleum Ministry.

The Venezuelan government used this authority to block some of these sales without any justification. An early precedent involved BP's attempts to sell its participation in two OSAs (DZO and Boqueron) to Perenco in 2004. At the time, contractually, PDVSA had to authorize Perenco's purchase of BP's OSAs. After agreeing on terms with the buyer, BP spent over a year trying to get the approval from PDVSA,[119] ultimately failing to obtain it and abandoning the plan altogether. PDVSA did not provide a reason for its refusal of the operation.[120] In 2008, the Petroleum Ministry refused to authorize Anadarko's sale of its participation in Petroritupano (formerly under the OSA Oritupano-Leona) to PetroFalcon.[121] One year later, the Ministry argued that PDVSA wanted to exercise its right of first refusal to acquire Anadarko's participation, but at a lower price.[122] PDVSA has not yet acquired Anadarko's participation. Harvest Natural Resources failed on two occasions to receive Venezuela's government approval to sell its stake in Petrodelta, first to the Indonesian national oil company Pertamina (2012), and then to a unit of Argentinian company Pluspetrol (2013).[123] In 2015, then PDVSA's President Eulogio Del Pino argued that PDVSA was trying to acquire Harvest's participation; PDVSA rejected Harvest's previous sale attempts because neither buyer would commit new investments or pay a bonus to the Venezuelan government.[124] CT Energy, a private domestic investment firm eventually bought Harvest's share in Petrodelta in 2016.[125] The Petroleum Ministry also threatened to take over the four JVs where Petrobras Energia participated during its acquisition by Pampa Energia if the buyer did not invest 500 million dollars to increase output.[126]

These cases show how investors could face significant barriers to exit from Venezuela. The requirement of the Petroleum Ministry's approval combined with the Venezuelan government's behavior increased the investors' political risks due to the higher costs of leaving the project whenever a dispute arose with PDVSA. The government appeared to opportunistically use its authority to uphold investors.

Another significant concern for investors was the lack of recourse and mechanisms at their disposal to solve investment or commercial disputes. During the *Apertura*, PDVSA and its international assets served as collateral or "hostage" of sorts, to get compensation in case of regulatory expropriation of their investments. Investors could elevate their claims to international arbitration and foreign courts.[127] Besides the international clauses contained in all *Apertura* contracts, investors had access to different international arbitration mechanisms established by the Bilateral Investment Treaties (BITs), the Convention on the Settlement of Investment Disputes between States and Nationals of other States (ICSID Convention), the 1999 Investment Law (*Ley de Proteccion de Inversiones*), the New York Convention, two Inter-American Conventions on Recognition and Enforcement of Arbitration Awards, and the 1999 Venezuelan Constitution favoring alternative dispute resolution mechanisms.[128]

In contrast, the new HOL, the new JVs' legislatively approved terms and conditions, and the contracts, all indicate that direct negotiations between partners and local courts are the main mechanisms to settle disputes. Article 34 of the HOL incorporates the possibility of arbitration in those cases established by law but forbids the use of international jurisdiction to settle disputes. In 2012, the Venezuelan government formally "denounced" the ICSID Convention to withdraw from the arbitration panel and limit future claims.[129] Venezuela has also denounced at least one BIT – the Netherlands-Venezuela BIT of 1991– that had been used by many investors to reach international jurisdictions.[130] With fewer options to settle disputes, investors face further political risks from the Venezuelan government and are naturally more careful before committing additional investments.

Additional Challenges

Investors in Venezuela also faced multiple challenges during the development of their projects. A recent concern has been the worsening crime and industrial security conditions in the oil fields. Partners in JVs have indicated recurring problems caused by theft of equipment and spare parts, hold-ups, and organized criminal groups, occasionally leading to disruptions in operations.[131] Even pirates looking for valuables frequently attacked several production platforms in the Maracaibo Lake.[132] Political turmoil has also increased uncertainty and risks for investors, causing delays in projects.[133] Investors have frequently removed expatriate workers due to worsening security conditions.[134]

There are also many problems associated with the lack of goods and services used as operational inputs. For example, investment projects in the *OOB* also faced the challenges caused by the scarcity of light crude used as a feedstock to dilute and transport the extra-heavy crude. Due to falling production in Eastern Venezuela, PDVSA started importing naphtha and light crude oil to maintain production in the OOB.[135]

Poor basic infrastructure has also hindered JVs' efforts to maintain and develop their investment projects. Widespread blackouts have temporarily affected oil fields and

facilities –including refineries, EHCO upgraders, and terminals– causing operational stoppages.[136] The frequency and intensity of these blackouts have increased over time, and in 2019 electric problems have been mentioned as one of the main factors affecting oil and gas operations in Venezuela. Infrastructure requirements for some areas are massive. For example, PDVSA estimated that OOB's new projects involved the construction of 15.5 million barrels of oil storage capacity, two new terminals, 1,380 km in new oil pipelines, the expansion of existing gas pipelines, and 2,199 km in new gas pipelines.[137] Other needs include approximately 5,000 MW in additional power generation capacity,[138] as well as basic services for the projected population growth of over 600 thousand people.[139] The Venezuelan government failed to build this basic infrastructure needed to sustain operations in the area.

The decline in oil prices in 2014 also had implications for investments in Venezuela. Firms had different reactions, but the global context saw a greater focus on existing operations, reduction in costs wherever possible, shifting efforts away from large and complex projects into smaller assets and short-cycle projects. All of these elements proved relevant for the operations in Venezuela, including greenfield projects in the Orinoco Oil Belt. High above-ground risks, combined with the need for massive sunken investments, made unviable projects that even when the price of oil was high were unlikely to move ahead.

Outcomes: Between Wishful Thinking and Hard Realities

Despite the ambitious government goals, almost all projects contemplated in the PSP failed to materialize – with only a few exceptions. According to the original PSP, by 2012, Venezuela expected to produce around 5.8 MBD. Instead, output fell to 2.9 MBD (Table 6). These goals were revised in light of the new Plan de la Patria (Fatherland Plan), according to which oil production would increase to 6.0 MBD, with 4.0 coming from the Orinoco Oil Belt (OOB). However, by 2018, oil production from the projects awarded since 2009 at the Orinoco Oil Belt (New OOB Projects) was below 3 percent of the initial target, and production from Brownfield OOB Projects was 21 percent of what was originally expected.

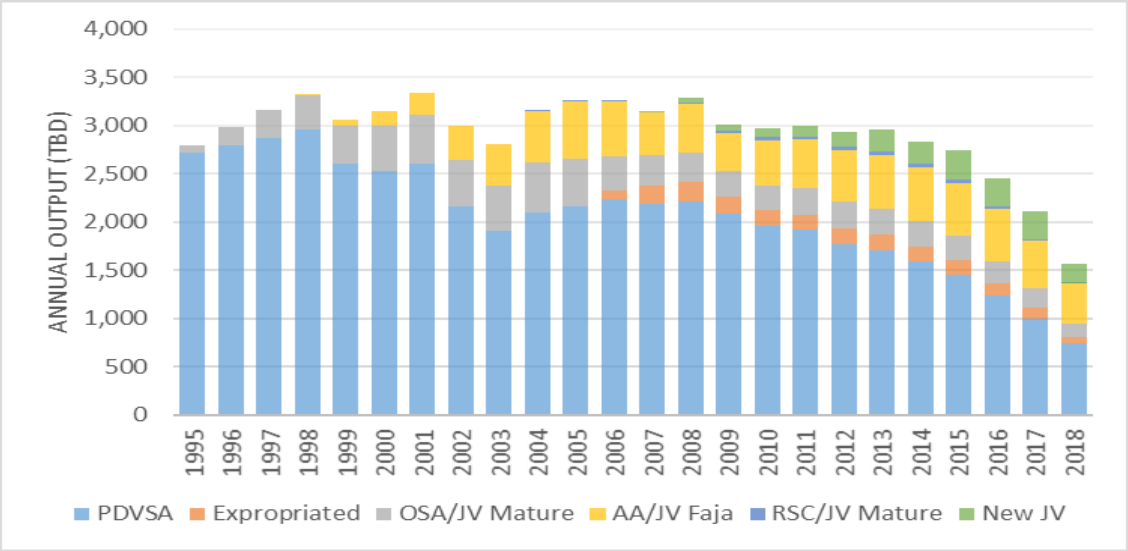
Table 6: PSP Goals and Real Output (thousand barrels per day)

	Output Target 2012	Real Output 2012	Output Target 2019	Real Output 2018
PDVSA direct management	4,000	1,829	2,000	765
Mature field JVs	460	463		279
Faja (OOB) JVs	622	645	1,910	458
New *Faja* (OOB) projects	615	0	2,090	69
Total	**5,697**	**2,937**	**6,000**	**1,571**

Sources: PDVSA Informe de Gestion Anual 2006, Petroleum Ministry Statistical Bulletin (PODE), Rystad Energy UCube, own calculations.

Instead of the expected growth, Venezuela's total oil production showed a decline since the start of the first Oil Sowing Plan, in 2005. Figure 9 shows that after the 2006 and 2007 expropriation and forced renegotiation of oil contracts, total production has continuously decreased. PDVSA's own production fell by over two-thirds, from 2.2 MBD in 2007 to 0.7 MBD in 2018; fields that were nationalized and taken over by PDVSA in 2006 and 2007 showed a similar trend. The JVs with international investors had a relatively better performance, with a decline of 26 percent. New JVs, along with new fields awarded to existing JVs, provided a peak of 0.3 MBD of new oil output in 2015 before falling to 0.2 MBD in 2018. JVs with international investors produced 30 percent of Venezuela's oil in 2007; by 2018, JVs produced 52 percent of Venezuela's oil.[140]

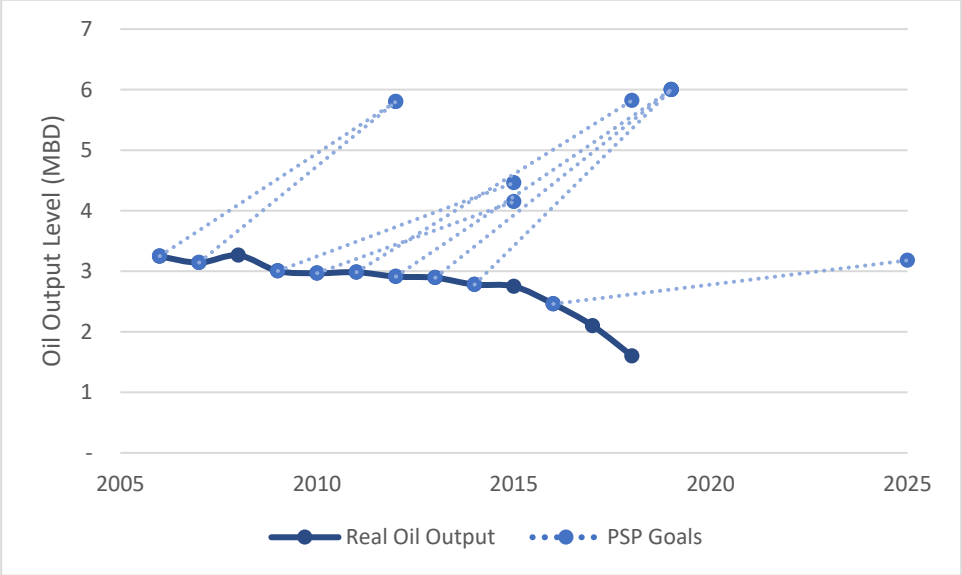
Figure 9: Venezuela's Oil Production



Sources: Petroleum Ministry Statistical Bulletin (PODE), Rystad Energy UCube, OPEC Monthly Oil Report, own calculations.

Over time, PDVSA and the Venezuelan government have updated the original PSP and redefine output timelines, but keeping ambitious production targets, even though production has been consistently declining. Figure 10 shows the evolution of the PSP goals between 2006 and 2016. While the 2016 PDVSA's Annual Results Report does not disclose an official output target, the prospectus of PDVSA's offer to exchange its 2017 bonds discloses the goal of reaching an output of 3.18 MBD by 2025,[141] acknowledging the production collapse and setting more moderate growth rates.

Figure 10: PSP Goals vs Real Output



Sources: PDVSA Annual Results Reports and Offering Circular for 2016 Bonds Exchange, PODE, Rystad Energy UCube.

As for investments, the Oil Sowing Plan 2005-2012, official estimates contemplated investments in the order of US$ 75.7 billion, out of which US$ 19.8 billion would come from third parties, largely foreign firms.[142] The Ministry of Petroleum, however, reported that foreign direct investments between 2006 and 2012 totaled USD 21.1 billion at the official exchange rate and USD 14.7 billion at the parallel exchange rate (Table 7).

Table 7: Foreign Direct Investment in Oil and Gas

Foreign Direct Investment (MM)	2006	2007	2008	2009	2010	2011	2012	Total
VEF	34,513	10,853	9	1	*2*	1	31	45,410
US$ (Official Exchange Rate)	16,053	5,048	4	0	1	0	7	21,113
US$ (Parallel Exhange Rate)	12,452	2,324	2	0	*0*	0	3	14,781

Source: Ministry of Petroleum Annual Report 2014

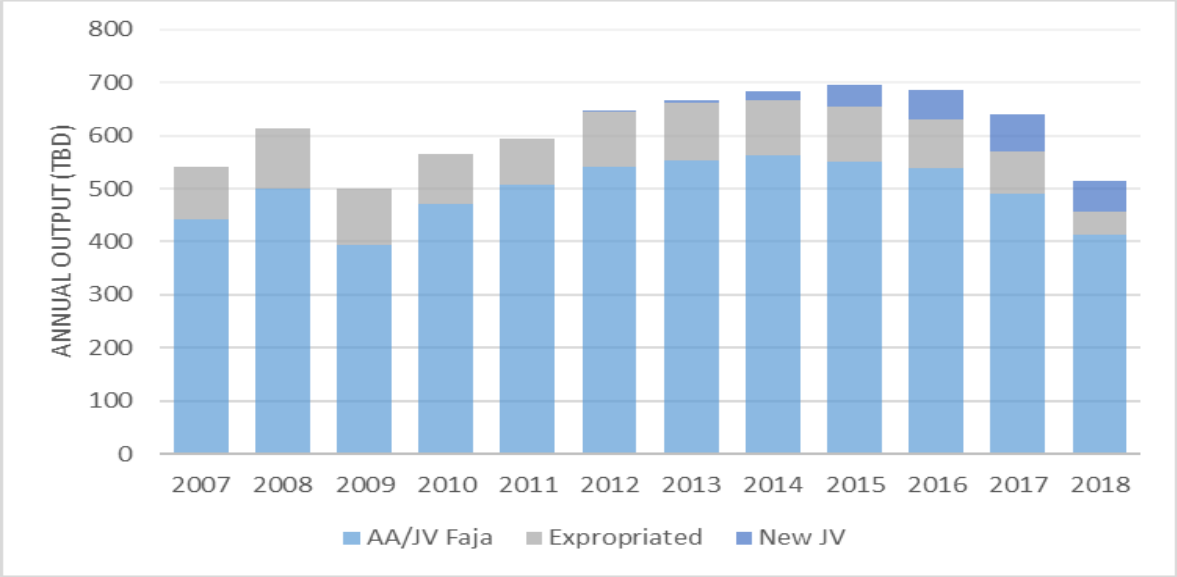
As for the Oil Sowing Plan 2013-2019, total investments were projected at US$ 257 billion, out of which US$ 49 billion would come from partners.[143] However, data estimated by Rystad Energy indicates that capital expenditures in JV projects reached approximately US$ 20.6 billion between 2013 and 2018, out of which less than half came from international partners.

Orinoco Oil Belt

As seen in Figure 11, the former AAs[144] have sustained OOB's oil output. The new projects that officially began in 2010 have not been able to ramp up production quickly enough; leading to an overall decrease in OOB's output of almost 200 TBD from its 2015 peak. By 2018, even the new projects' production started to fall. Figure 12 also shows

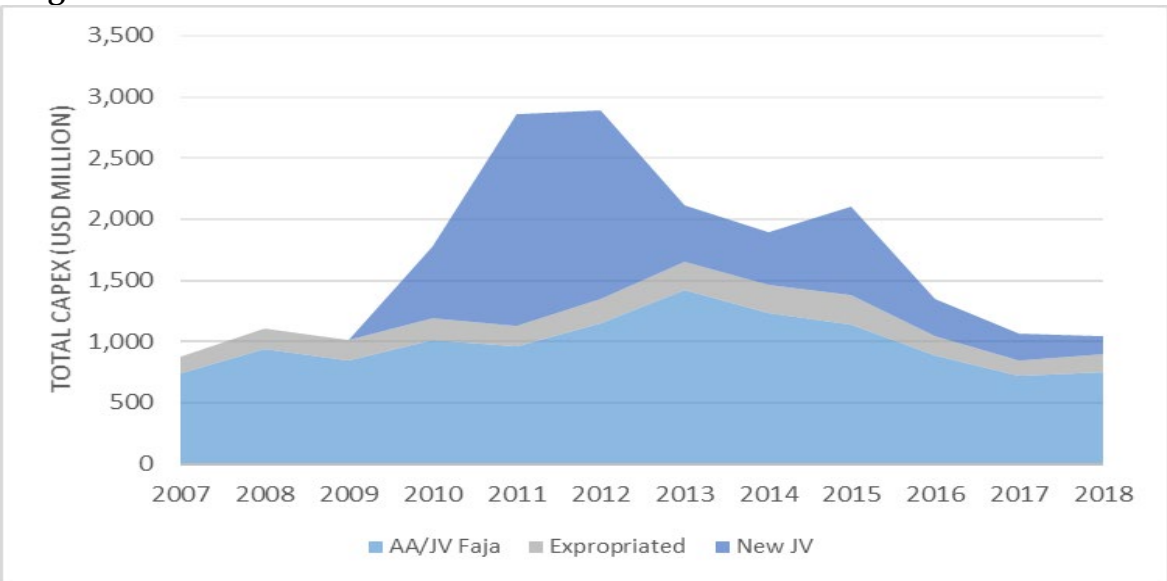
CAPEX levels growing after Carabobo's auction and Junín areas' awards, but then quickly falling and failing to materialize the goals set-up by the Venezuelan government.[145]

Figure 11: Output in Orinoco Oil Belt



Sources: Ministry of Petroleum Statistical Bulletin (PODE), Rystad Energy UCube, own calculations.

Figure 12: CAPEX in Orinoco Oil Belt



Sources: Rystad Energy UCube, own calculations.

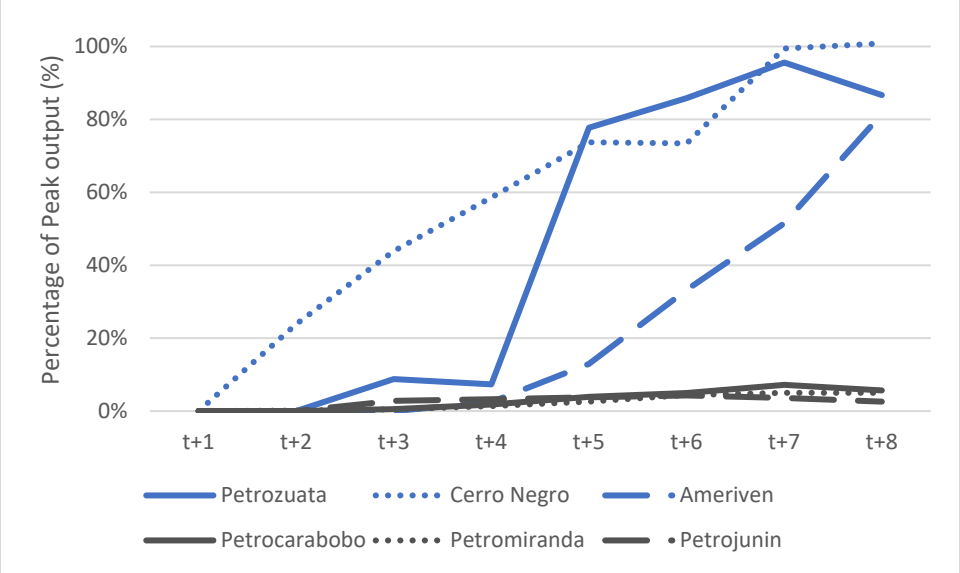
Table 8: Summary Orinoco Oil Belt Greenfield Projects

Project	Start year	Block	Output targets		Expected CAPEX (USD million)	CAPEX 2010-18 (USD million)
			Output (TBD)	Year		
Petrocarabobo	2010	Carabobo 1	400	2017	12,000	
Petrovictoria	2014	Carabobo 2	400	2019	14,400	
Petroindependencia	2010	Carabobo 3	400	2017	12,000	
Petromacareo	2010	Junín 2	200	2015	8,000	
Petrourica	2010	Junín 4	400	2016	16,300	
Petrojunín	2010	Junín 5	240	2016	8,300	
Petromiranda	2010	Junín 6	450	2017	18,000	
Total			**2,490**		**89,000**	**7,448**

Sources: PDVSA Annual Performance Report 2010, Rystad Energy UCube

These results contrast with the expectations for each of the seven new developments in the OOB (Table 8). Most projects had an output goal of 400 TBD each, for a total incremental volume of 2.5 MMBD. Based on figures for 2018, the most advanced projects are Petrocarabobo (in partnership with Repsol, ONGC, Indian Oil, and Oil India Limited), Petromiranda (in partnership with Rosneft and Gazprom) and Petrojunín (in partnership with Eni), but their combined production is less than 3 percent of the target production. Taking advantage of the technical similarities between OOB's new developments and *Apertura's* AAs,[146] Figure 13 shows that the new projects' present significant delays eight years after their development began.

Figure 13: Comparison of OOB Projects: AAs (blue) and New Developments (gray)

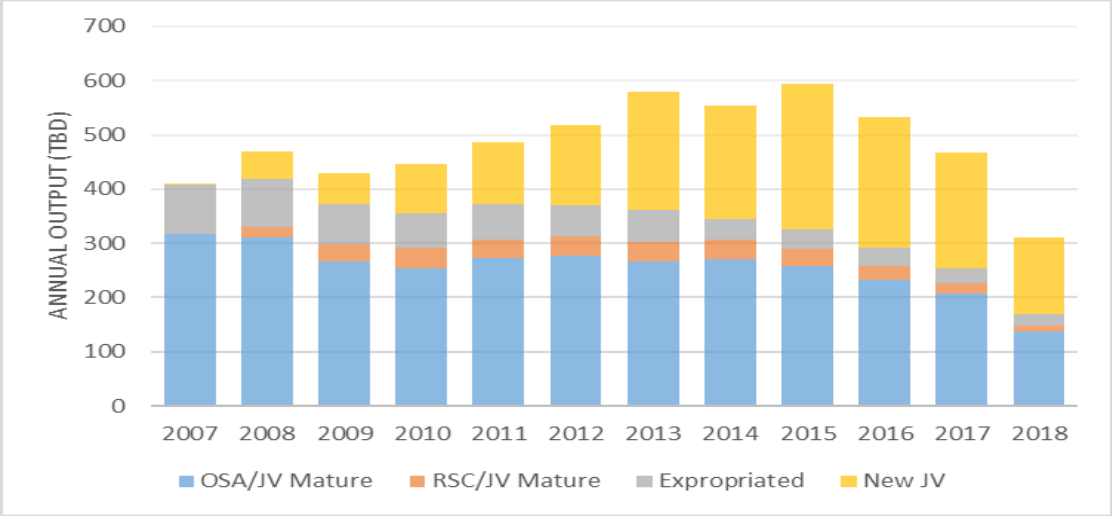


Sources: Ministry of Petroleum Statistical Bulletin (PODE), Rystad Energy UCube, own calculations.

Mature Fields

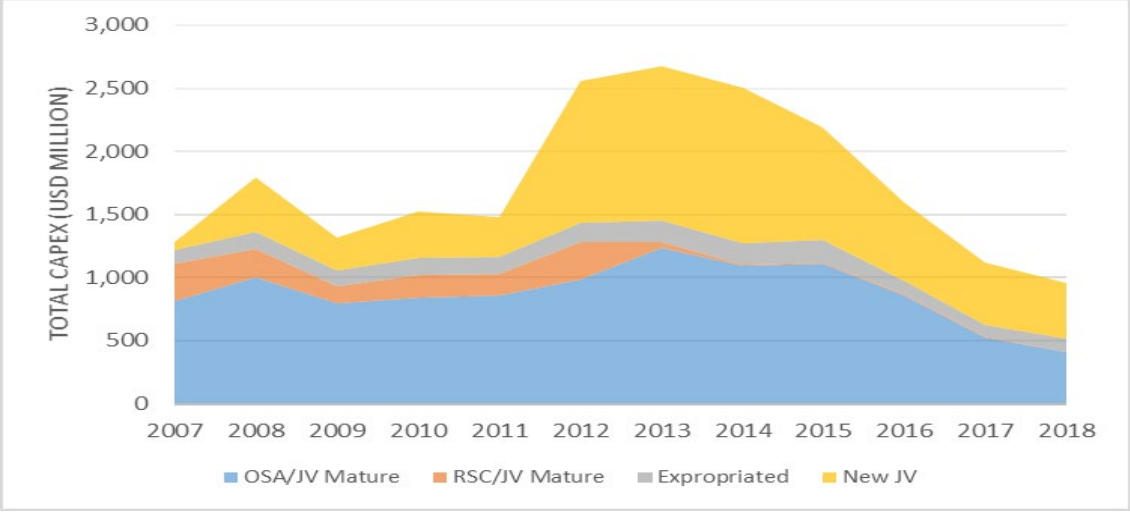
Most petroleum output in mature fields consistently came from the former OSAs, maintaining production levels close to 300 TBD before declining by over 50 percent between 2014 and 2018. Production in new JVs and new areas reached a peak of 267 TBD in 2015 but declined by a similar rate of 49 percent by 2018 (Figure 14). CAPEX estimations by Rystad indicate that falling output generally matched a fall in annual investments across most JVs. Figure 15 shows how overall CAPEX in former OSAs fell from USD 1.1 billion in 2015 to USD 400 million in 2018; for new JVs, CAPEX fell from USD 1.2 billion in 2014 to USD 440 million in 2018. All of this implied a lower activity in the sector, even before the decline in oil prices or the imposition of sanctions.

Figure 14: Output in Mature Fields JVs



Sources: Ministry of Petroleum Statistical Bulletin (PODE), Rystad Energy UCube, own calculations.

Figure 15: CAPEX in Mature Fields JVs



Sources: Rystad Energy UCube, own calculations.

Natural Gas Fields

The natural gas projects also fell short of expectations, although in this area at least one major offshore project, Cardon IV, was fully developed. Total natural gas output increased from 7.1 MCFD in 2006 to 7.9 MCFD in 2016; private operators and JVs provided 1.6 MCFD by 2016. Out of the 18 non-associated gas licenses in Venezuela with international investors, only five were developed and have commercial production. From this group, just two projects were greenfield projects: Yucal-Placer, with partners Total, Repsol, Otepi and Inelectra; and Cardón IV, with partners Eni and Repsol. It should be noted that the later project was fully owned by the private partners, as allowed by the natural gas legal framework, so they did not have the obstacles that JVs faced of having PDVSA as a majority partner. Despite being the only successfully concluded greenfield projects, Yucal-Placer and Cardon IV show the risks of investing in Venezuela: PDVSA sold the gas volumes to the domestic market at massively subsidized prices and delayed payments to the operators and foreign partners. PDVSA accumulated massive arrears leading ENI and Repsol to write-off their investments.

The other three licenses granted to JVs with international investors had been already developed when assigned to investors: Inpex and Repsol originally developed Gas Guarico and Quiriquire Gas fields under OSAs, and Zamaca Oeste was already producing natural gas when assigned to Petrolera Bielovenezolana.

Table 9: International Investors Withdrawing from Venezuela

Investors	Projects	Year	Reason
Anadarko	Petroritupano	2008	Undisclosed
BP	Boquerón Petroperijá Petromonagas	2010	Assets' sale to cover cleanup costs following the Macondo well explosion.[147]
Harvest	Petrodelta	Initially 2012	The company had problems getting paid for its production in Venezuela as well as repatriating dividends.[148]
Petronas	Petrocarabobo	2013	Deteriorating relations with PDVSA and disagreements on the economic terms.[149]
Surgutneftegas	Petromiranda	2013	Focus on domestic projects.[150]
Petrovietnam	Petromacareo	2014	Worsening economic conditions. Petrovietnam later indicated that its participation was only suspended and that they would restart activities.[151]
Lukoil	Petromiranda	2014	Low priority among projects in its investment portfolio.[152]
Petrobras	Petroritupano Petroven-Bras Petrowayú Petrokariña	2016	Petrobras sold its participation in Petrobras Argentina as part of a divestment plan following financial scandals and lower oil prices.[153]
Gazprombank	Petrozamora	2019[154]	Undisclosed

The Decision to Leave Venezuela Projects

As the conditions for investment proved enormously challenging, some companies took the decision to abandon their operations in the country, under different arguments, as shown in Table 9. This affected both OOB projects and some mature fields in other parts of the country.

Recent Attempts to Recover Output and Attract Investment

A combination of falling output, worsening economic conditions, and lower oil prices increased Venezuela's political willingness to relax some of the regulations and conditions applied to the oil industry. As predicted by the theory, as oil prices collapsed, production continued to decline and the national company was unable to invest, the government, desperate to increase its revenues became much more willing to liberalize investment conditions. However, the lack of credibility and the persistence of high risks made it an almost impossible task. Particularly, since Venezuela is competing with most other countries in the region, who are also liberalizing their oil sectors, and have lower above-ground risks. Moreover, shale investments in the US are also an attractive low-risk alternative for the oil companies that traditionally invested in Latin America.

PDVSA negotiated a new model of contracts with service companies starting in September 2016. The first group of contracts aimed at drilling 480 new wells over 30 months to increase output by 250 TBD in three OOB JVs, Petroindependencia, Petrocarabobo, and Petrovictoria. Total investment was expected to reach USD 3.2 billion. Contractors included Schlumberger, Horizontal Well Drillers, and local company Y&V, with technical support from Halliburton and Baker Hughes.[155] Contractors would receive a fee for well completed and for all services performed, while payments would be deferred until the incremental output reached a contractually set level. It is important to note that contractors were not entitled to participate in the JV's profits, or receive any incentive related to production.[156]

The design of these new integrated service contracts shows similarities with the first versions of the OSAs, although the decision-making process remains within the JV and not the contractor. The HOL and the terms and conditions require JVs to act as operator, forbidding the transfer of such role to third parties. To avoid payment delays from PDVSA, the contracts allowed payments either through a trust account, collecting the revenues from the incremental output –similar to the model applied for JVs with financial agreements– or direct payments from the final buyer of oil.[157] The contracts also include a version of an economic equilibrium clause, allowing the contractors to adjust the fee they receive due to regulatory changes related to new taxes, changes in the minimum wages, and adjustments to the Collective Labor Convention.[158]

PDVSA's decision to award the new integrated service contracts responded to an increasing need for pragmatism to reverse declining oil production. The innovations included in these contracts were designed to avoid some of the challenges analyzed in

this document, mainly PDVSA's poor cash flow management, legal and economic uncertainty, and centralized decision-making especially in terms of operation management.

In October 2016, PDVSA may have applied a similar scheme for another group of contracts with two companies – China-based Shandong Kerui Group and the Bulgarian-Venezuelan Consortium Aleco – with the purpose of reactivating 931 wells in Lake Maracaibo. These contracts would increase oil output by 50 TBD and, based on the statements of former PDVSA President Eulogio Del Pino, incorporate payments based on incremental output.[159] While the terms of the contracts are not public, the payment scheme could be similar to that used in the integrated service contracts for the OOB.

PDVSA signed a final group of integrated services contracts in August 2018.[160] The scope of these contracts, however, differs from the previous model used in 2016. For this group of contracts, PDVSA signed "joint service agreements" with seven companies to increase output in seven fields, three of which were previously operated under OSAs.[161] While PDVSA did not disclose the specific contractual terms, an internal document reviewed by Reuters indicates a structure similar to the *Apertura's* OSAs. Each company would take control of a field for six years, finance the required investments, and conduct operations. Companies would also receive a fee for each additional barrel produced and reimbursements for the investments they make. A trustee account would collect oil sale revenues to avoid payment delays.[162] It is not clear if these contracts fully comply with the HOL requiring that a state company or JV maintains control of primary activities; in practice, these agreements would provide operational control to private companies, reversing a key policy since 2006.

A second measure meant to promote further investments was the decision to exempt PDVSA and JVs from income tax payments.[163] This was the first time in over 20 years that the Venezuelan government decided to reduce its government-take. The reduction in the income tax rate in 2001 stemmed from a decision to increase the royalty rate. The income tax exemption, however, will only apply for the 2018 fiscal year; without any further adjustments, this decision fails to improve the long-term attractiveness of investment projects in Venezuela.

A third recent policy decision involved reforming the Venezuelan FX regime in January 2018, establishing a unified and fluctuating exchange rate.[164] According to BCV data, the unified exchange rate has roughly kept pace with domestic inflation during 2018. While this policy decision may not have been directed specifically to the oil industry, a single exchange rate system could correct some economic distortions affecting PDVSA and JVs.[165]

The dire economic conditions in Venezuela may have pushed the Venezuelan government to adopt measures providing flexibility to private companies, some level of fiscal relief, and a more competitive FX regime. Crude oil output fell by almost 1.2 MMBD between 2016 and 2018. CAPEX estimations by Rystad Energy indicate that annual investments in oil fields fell from an average of USD 7.7 billion between 2011

and 2015, to just above USD 4 billion between 2016 and 2018. In 2016, international oil prices fell to their lowest levels since the 2008 financial crisis and have fluctuated around 60 USD/B, significantly lower than the 2010-2014 average. The IMF estimates that Venezuela's GDP recorded a fifth consecutive year of negative growth in 2018, indicating an accumulated loss of 70 percent.[166]

The adopted policy measures, however, may fail to attract significant investments in Venezuela's oil and gas industry. Even if the government signals the political will to provide additional flexibility to investors, the same legal and fiscal regime remains in place. The income tax exemption was only temporary and applicable to one year; all other taxes and contributions – including the WPT – remain unchanged. The HOL still requires PDVSA to have majority participation in all projects, exerting control over most decision-making processes. The overall legal framework fails to provide stability to the existing terms, increasing investors' political risks and the long-term costs to attract much-needed investments to the oil and gas industry.

Economic Sanctions and FDI

Since 2015, when President Obama issued Executive Order (EO) 13692, the U.S. government has imposed several sanctions on Venezuelan government officials and the National Oil Company, Petroleos de Venezuela (PDVSA).

Sanctions initially targeted senior government officials and people with direct responsibility in human rights violations, political violence, and corruption, among other charges. These sanctions prevented from engaging in any transactions or dealings with these individuals, among other restrictions. Later, in 2017, President Trump issued EO 13808 that "prohibits transactions by a United States person or within the United States related to certain new debt of PDVSA and certain new debt or new equity of the Government of Venezuela". In addition, EO 13808 "prohibits the purchase by a U.S. person or within the United States of most securities from the Government of Venezuela".

In January 2019 the Trump administration took a broader stance with EO 13850 directly sanctioning PDVSA. All property and interests in property of PDVSA subject to U.S. jurisdiction are blocked, and US persons are prohibited from engaging in transactions with the company.[167] This measure not only prevented PDVSA from engaging in financial transactions with US financial institutions (effectively restricting its ability to finance its operations) but also cut PDVSA's imports from US refineries. Moreover, revenues from PDVSA sales to US buyers were directed to a blocked account in the United States, effectively halting PDVSA's exports to the US. Finally, in August 2019, the Trump administration authorized secondary sanctions on non-US companies and persons assisting the Maduro government.

The Office of Foreign Assets Control (OFAC) issued temporal general licenses allowing certain transactions related to PDVSA and its subsidiaries. General License No. 8 authorized several U.S. companies with operations in the Venezuela oil industry,

including Chevron, Halliburton, Schlumberger, Baker Hughes, and Weatherford, to maintain operations. These activities were initially authorized until July 27, 2019, and later extended until October 25, 2019.

There are several implications for foreign partners of these sanctions. First, sanctions restricted PDVSA's ability to finance its operations, including its share in the JVs CAPEX. Sanctions also affected the financial agreements based on offshore trust accounts that mitigated PDVSA's cash-flow problems suffered by the JVs and service companies. While transactions in dollars linked to PDVSA or its joint ventures remain banned, the European Union has not prohibited operations in euros. Nevertheless, many banks are not authorizing euro bank accounts to firms associated with PDVSA or transactions that can ultimately be traced to it, which has left the state-run firm with frozen money all over the world.[168]

PDVSA can no longer import products from the US, halting the acquisition of diluents required for the blending activities in the OOB.[169] US firms Halliburton, Schlumberger, Baker Hughes, and Weatherford, provide critical services to prevent further decline in oil and gas production. Some energy analysts believe that the trend of declining production will get worse if licenses from OFAC are not renewed.[170]

Foreign governments with interests in Venezuela's oil industry have shown different responses to US sanctions. In March, Indian refiner Reliance announced it would cap its crude purchases with Venezuela to comply with US sanctions. A Reuters report quotes a source indicating "there is panic among oil companies about how the US government will interpret the new executive order since it could lead to secondary sanctions – not at the level of Iran, but close. Every punitive measure by the United States generates a corrosive effect."[171] Some authors also argue that in cases such as India, business rather than politics drives the bilateral relation.[172] This, more than anything else, dictates the policy position of both countries. They are both in it for the long run, regardless of which political dispensation is in power in either country. It has also been reported that companies were in talks with PDVSA about publicly declaring their commitment to their joint-ventures.[173]

In the case of China, Petrochina decided to suspend the loadings of Venezuelan crude. [174] While initially seen as a sign of caution against secondary sanctions, Petrochina's action may also respond to short-term market dynamics, given the size of the resources attached to CNPC projects in Venezuela. [175]

Russia's Rosneft has been the most consistent investor in Venezuela, not only maintaining its presence in oil and gas projects but also helping Venezuela circumvent the sanctions and minimize their impact. Its Indian refining unit Nayara has been among the leading buyers of Venezuela´s heavy sour crude recently. Rosneft also supports Venezuela by carrying marketing activities: Rosneft acquired 40 percent of Venezuela's July oil shipments and 66 percent of August's. The oil is destined both for its Nayara subsidiary and independent refiners in China.[176] It has also been reportedly

involved in supplying light crude oil from Nigeria for blending operations in the Orinoco Oil Belt.

Although US sanctions have been a clear contributing factor in the recent decline of the Venezuelan oil industry, particularly since 2019, the root causes of the collapse have been accumulating for years. On the foreign investment side, the above-ground risks explain how the country with the largest resource base in the world was not able to increase investments during the oil price boom, even though it tried.

Concluding Comments

During the last 30 years, Venezuela has shown two different policy models towards FDI in the oil and gas industry. Venezuela applied the first model during the 1990s *Apertura*, within a context of low oil prices, falling oil output, and financial restrictions. At the moment, the Venezuelan government perceived that the political costs of a sector-wide reform were too high, favoring a contractual approach to offer legal guarantees to investors in the case of investment disputes. The fiscal conditions were such that allowed for enough profitability to attract the large investments required for integrated projects. Interested companies were mostly IOCs with relevant experience in the sector, potential to scale up investments, and technologies in frontier areas like the OOB. Despite the legal risks, this model mobilized billions of dollars in new FDI, developed new infrastructure and reserves, and increased Venezuela's production capacity by more than one million barrels per day.

Venezuela applied a second policy model starting in 2006. While the Hydrocarbons Law of 2001 showed Venezuela's intention of capturing a larger share of oil and gas rents in future foreign investments, existing projects, contracts, and conditions were initially kept in place. As the investment cycle of the *Apertura* ended, the large OOB projects finished their construction phases in the early 2000s, deploying billions in sunken assets; a few successful exploration finds started commercial production, and the oil prices boomed; the Venezuelan government moved to expropriate foreign investors. A perfect storm of conditions that encouraged opportunistic expropriation had happened, in what was only the first and more spectacular episode of the resource nationalism wave that swept the region.

The Chávez model for the oil industry focused on increasing the government-take and reinforcing the government's control over the industry. However, by 2008, the government, facing declining production, realized that they needed to launch a new investment cycle and moved aggressively to try to attract a massive wave of new investment.

However, the institutional weakness and the legal instability inherent in Venezuela's oil policy post-2006 caused concerns among international investors, many of which refrained from larger commitments in the country. Despite low geological risks and booming prices, the above-ground risks were too high. Geopolitical motivations brought some new investors, mostly NOCs from politically aligned countries trying to

secure energy resources and political influence. China, Russia and, to a minor extent, a few other countries, successfully used loans and diplomacy to acquire production rights and oil reserves, while also trying to protect their investments through BITs and political leverage. Overall, however, the challenges caused by the fiscal terms, excessive reliance on PDVSA's inefficient operations, economic instability, discretionary policies, and poor investor protection, led to the failure of almost every single new investment project since 2006.

Venezuela's policy model since 2006 produced, not only the failure of investment projects, but also a steady decline in oil and gas production, only recently accelerated by lower oil prices, the electric crisis, and the economic sanctions imposed on PDVSA. What should have been a production boom, shockingly turned into a production bust. The lack of reforms to remove several legal and operational constraints on the sector, and the uncertainty surrounding the political and economic environment in the country removed policy stability and predictability, posing several challenges for the future.

The Need for Reforms

This paper compares two distinct periods of Venezuelan oil and gas policy and their impact on FDI and investment projects. It reveals some important lessons both for foreign investors planning new projects and for governments dealing with the challenge of designing a stable legal and fiscal framework for their oil and gas industries.

The first lesson indicates that investor protections help in fostering contractual stability, but they are not enough by themselves. Legal and contractual protections for investors increase the economic costs of opportunistic behavior, preventing costly renegotiations. These mechanisms can take many forms: BITs, contractual international arbitration, or economic stability clauses. The case of Venezuela shows, however, that legal protection mechanisms are not necessarily enough to provide contract stability in the face of weakening domestic institutions and strong incentives for expropriation given by high oil prices, regressive government-take, and the end of an investment cycle. The 2006/2007 renegotiation and expropriation process in Venezuela occurred amid a progressive institutional deterioration with increasing accumulation of power in the executive. While legal protection mechanisms embedded in the *Apertura* contracts raised the costs of renegotiation, the benefits perceived by the executive power –using mechanisms as FONDEN to manage discretionally the oil rent– were much higher. A combination of adequate legal protections for investors and domestic institutions constraining executive power may be more effective reducing the likelihood of renegotiations.

The second lesson is the need for progressive and flexible fiscal regimes that are predictable, to reduce the renegotiation risks for investors. Venezuela's regressive fiscal regime, established during the 1990s *Apertura*, increased the likelihood of a contract renegotiation once oil prices rose. Moreover, the introduction of a progressive component in 2008, in the form of the WPT, actually created additional risks due to its

discretionary characteristics. While the post-2001 fiscal regime included some incentives Venezuela could use to attract further FDI, these incentives were awarded at the will of the Ministry of Petroleum. The economic viability of most investment projects relied on the decisions by a small group of persons within the government. This structure increased the risks for investors, as they could not accurately predict the future decisions of government officials and, therefore, struggled to manage the political risks of investing billions of dollars in Venezuela in decades-long projects. Clear rules about how the fiscal regime will adapt to circumstances as changing oil prices or increasing costs, will help mitigate the political risk for investors and could reduce the costs to attract investments.

A third lesson is that maintaining credibility can reduce transactional costs, both for investors and for governments. One of the main causes of Venezuela's failure to attract FDI is the low credibility of its government in terms of respecting contractual terms. Foreign investors were willing to sign-in to massive OOB projects under the legal and fiscal framework defined during the Chávez presidency. But, PDVSA's failure to comply with its basic contractual commitments –in terms of respecting the autonomy of JVs or complying with payment schedules – led investors to confirm that the "new PDVSA" could not be trusted as a partner. The "solutions" of creating offshore trustee accounts or integrated service contracts also generated years-long delays and transaction costs that PDVSA could have avoided if it had respected the terms it negotiated.

Finally, the experience of Venezuela's oil and gas sector highlights the need for an institutional reform if it wants to attract large flows of FDI. Venezuela can adjust its legal and fiscal framework to solve most of the short-term challenges that affected FDI flows. Punctual legal changes can adjust tax levels, reduce PDVSA's control over JVs, and grant flexibility to contractual terms. However, there are fundamental changes to be addressed to ensure the long-term competitiveness of the sector. Some of those changes require a different institutional arrangement, where the roles of PDVSA as an operator are separated from those of the government as the regulator. For example, by creating a strong and autonomous regulator like those created in Brazil and Colombia. It stresses the importance of autonomous institutions with enough capabilities to implement long-term policies for the operation of the oil and gas sector. Having stable macroeconomic policies, with a predictable fiscal regime, and a functioning court system that protects long-term investments from short-term political instability, are key elements to drive FDI into the country. These factors can be more important for international investors than short-term incentives with low credibility.

The focus of this research was on upstream operations, given their importance in the overall performance of the sector, but further work on this area must also consider the study of downstream operations, as well as the relationship with companies that provide goods and services for the sector, given foreign involvement in many of these areas and their importance on a possible reactivation of the industry in Venezuela.

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Terms and Definitions:

Apertura Petrolera (Apertura) – Oil Opening

Ministerio de Energía y Petróleo (Petroleum Ministry) - Government's oil and gas regulator

Petróleos de Venezuela (PDVSA) – National Oil Company

Ley Orgánica de Hidrocarburos (HOL) – Hydrocarbons Law

Ley Orgánica de Hidrocarburos Gaseosos (GHOL) – Gas Hydrocarbons Law

Gaceta Oficial (GO) – Official Gazette

Empresas Mixta (JV) – Joint Venture

Faja del Orinoco (OOB) – Orinoco Oil Belt

Plan Siembra Petrolera (PSP) – Oil Sowing Plan

OSA – Operating Service Agreement

AA – Associations Agreement

RSC – Risk-Sharing Contracts

Bd – Barrels per day

Kbd – Thousand barrels per day

Mbd – Million barrels per day

USD – US dollars

VEF – Venezuelan bolivars

Tcf – Trillion cubic feet

MM – Million

EHCO – Extra-Heavy Crude Oil

OPEX – Operating Expenses

CAPEX – Capital Expenditures

WPT – Windfall Profits Tax

Appendixes

Appendix 1 - Estimating Venezuela's oil production data

Obtaining timely and accurate oil production data for Venezuela is challenging. Official information comes from the Ministry of Petroleum's annual statistical bulletin (PODE), or from PDVSA's annual reports. However, the Ministry of Petroleum stopped updating PODE figures since 2014, and PDVSA has not presented its annual reports since 2016. These two sources usually present conflicting information in terms of oil production levels. PDVSA's data also lacks the detail that can be found in PODE's figures. Updated information sources include OPEC's monthly oil market report, presenting country-level figures. OPEC data come from, either, direct communication from member countries or from secondary sources estimates; for Venezuela, these sources present a difference as large as 300 Kbd between 2013 and 2018.

To maintain consistency for this paper's timeframe, we estimate a unified time series for Venezuela's total oil production, including the detail for each oil field. Most of our data come from PODE, which is available from 1995 to 2014 and presents both national aggregates and field-level figures. We project national production figures from 2014-2018 using PODE's number for 2014 and extrapolating it with the annual variations that the Venezuelan Government reported to OPEC (direct communication figures). To estimate the distribution among Venezuelan fields, we use data from Rystad Energy UCube. Finally, we calculate PDVSA's own production data (excluding JVs) as the difference between our national estimates and the sum of all JVs' output.

Appendix 2 - Original Operating Service Agreements

OSA Round	Year	Field	Partners	Share
First Round	1992	Guárico Oriental	Teikoku	100%
		Monagas Sur	Benton (Harvest)	50%
			Vinccler Oil and Gas	50%
		Pedernales	BP	100%
Second Round	1993	Falcón Este	Pennzoil	70%
			Vinccler Oil and Gas	30%
		Falcón Oeste	Samson	85%
			Vepica	5%
			Ingenieria 5020	5%
			Petrolago	5%
		Guárico Occidental	Mosbacher Energy	100%
		Oritupano-Leona	Norcen International	45%
			Perez Companc	45%
			Corod	10%
		Quiriquire	Maxus	95%
			Otepi	5%
		Urdaneta Oeste	Shell	100%
		Colón	Tecpetrol	44%
			Coparex International	13%
			CMS Energy Corporation	29%
			Wascana Energy	15%
		DZO	Occidental Petroleum	100%
		Jusepín	Total	100%
		Quiamare-La Ceiba	Astra Capsa	25%
			Sipetrol	25%
			Ampolex	25%
			Tecpetrol	25%
		Sanvi Güere	Teikoku	100%
Direct Assignment	1995	Boscán	Chevron	98%
			Inelectra	2%
Third Round	1997	Acema	Perez Companc	50%
			Corepli	50%
		Casma-Anaco	Cosa-Ingenieros Consultores	30%
			Cartera de Inversiones Petroleras	50%
			Phoenix International	20%
		Ambrosio Sur	Phillips Petroleum	100%
		Boquerón	Union Texas Petroleum	67%
			Preussag Energie	33%
		Cabimas	Preussag Energie	90%
			Suelopetrol	10%
		Intercampo Norte	CNPC	100%
		Kaki	Arco	56%
			Inelectra	30%

OSA Round	Year	Field	Partners	Share
			Polar	14%
		LL-652	Chevron	30%
			Statoil (Equinor)	30%
			Phillips Petroleum	20%
			Arco	20%
		La Concepción	Perez Companc	90%
			Williams	10%
		Mata	Perez Companc	70%
			Jantesa	30%
		Mene Grande	Repsol YPF	100%
		Onado	CGC	50%
			Carmanah	23%
			KNOC	14%
			Distral	12%
		B2X-68/79	Pennzoil	54%
			Nimir Petroleum	18%
			Ehcopek Petroleo	9%
			Cartera de Inversiones Petroleras	9%
			Petroleo y Gas Inversiones	10%
		B2X-70/80	Pennzoil	50%
			PanCanadian	50%
		Caracoles	CNPC	100%
		Dación	Lasmo	100%
		Maulpa	Arco	56%
			Inelectra	30%
			Polar	14%

Appendix 3 - Original Association Agreements

Association Agreement	Year	Partners	Share
Petrozuata	1995	Conoco	50.1%
		PDVSA	49.9%
Sincor	1997	Total	40.0%
		PDVSA	30.0%
		Statoil	15.0%
		Norsk Hydro	15.0%
Cerro Negro	1997	Mobil	41.6%
		PDVSA	41.6%
		Veba Oil	16.8%
Ameriven	1997	Atlantic Richfield	30.0%
		PDVSA	30.0%
		Phillips	20.0%
		Texaco	20.0%
Sinovensa	2001	CNPC	70.0%
		PDVSA	30.0%

Appendix 4 - Original Risk Sharing Contracts

Area	Year	Partners	Share
La Ceiba	1996	Mobil	50%
		Veba Oil	30%
		Nippon Oil	20%
Golfo de Paria Oeste	1996	Conoco	100%
Golfo de Paria Este	1996	Enron	90%
		Inelectra	10%
Guarapiche	1996	BP	38%
		Amoco	38%
		Maxus	25%
San Carlos	1996	Perez Companc	100%
Punta Pescador	1996	Amoco	100%
Delta Centro	1996	Louisiana Land and Exploration Company	35%
		Benton	35%
		Noreen	30%
Guanare	1996	Elf	50%
		Conoco	50%

Appendix 5 - 2006/2007 Migration Process to Joint Ventures – Former OSAs

OSA (2005)	Partners	Share	Operator (2007)	Partners (2007)	Share
Boquerón	BP OMV	67% 33%	Boquerón	PDVSA BP OMV	60% 27% 13%
DZO	BP	100%	Petroperija	PDVSA BP	60% 40%
Rosario Colón	Tecpetrol Lundin Petroleum Perenco	44% 13% 44%	Baripetrol	PDVSA Tecpetrol Lundin Petroleum Perenco	60% 18% 5% 18%
Onado	CGC KNOC AGD	65% 14% 21%	Petronado	PDVSA CGC KNOC AGD	60% 26% 6% 8%
Boscán	Chevron Inelectra	98% 2%	Petroboscán	PDVSA Chevron Inelectra	60% 39% 1%
LL-652	Chevron Equinor BP	30% 30% 40%	Petroindependiente	PDVSA Chevron	75% 25%
Caracoles	CNPC	100%	Petrolera Sino-Venezolana	PDVSA CNPC	75% 25%
Intercampo Norte	CNPC	100%			
Monagas Sur	Harvest Petrofalcon	80% 20%	Petrodelta	PDVSA Harvest Petrofalcon	60% 32% 8%
B2X-70/80	Maurel & Prom	100%	Lagopetrol	PDVSA Maurel & Prom Ehcopek CIP	69% 26% 3% 2%
Kaki	Inelectra Polar	86% 14%	Petrolera Kaki	PDVSA Inelectra Polar	60% 23% 17%
Casma Anaco	CIP OPEN	58% 43%	Petrocuragua	PDVSA CIP OPEN	60% 28% 12%
Ambrosio	Perenco	100%	Petrowarao	PDVSA Perenco	60% 40%
Pedernales	Perenco	100%			
Acema	Petrobras Corepli	86% 14%	Petroven-Bras	PDVSA Petrobras Corepli	60% 35% 6%
La Concepción	Petrobras Williams	90% 10%	Petrowayu	PDVSA Petrobras Williams	60% 36% 4%
Mata	Petrobras Jantesa	86% 14%	Petrokariña	PDVSA Petrobras Jantesa	60% 35% 6%

OSA (2005)	Partners	Share	Operator (2007)	Partners (2007)	Share
Oritupano Leona	Anadarko Petrobras	45% 55%	Petroritupano	PDVSA Anadarko Petrobras	60% 18% 22%
Quiriquire	Repsol	100%	Petroquiriquire	PDVSA	60%
Mene Grande	Repsol	100%		Repsol	40%
Urdaneta Oeste	Shell	100%	Petroregional del Lago	PDVSA Shell	60% 40%
Cabimas	Suelopetrol	100%	Petrocabimas	PDVSA Suelopetrol	60% 40%
Guárico Oriental	Teikoku	100%	Petroguárico	PDVSA Inpex	70% 30%
Falcón Este	Petrofalcon	100%	Petrocumarebo	PDVSA	60%
Falcón Oeste	Samson	100%		Petrofalcon	40%
Guárico Occidental	Repsol	100%	PDVSA	PDVSA	100%
Sanvi Güere	Teikoku	100%	PDVSA	PDVSA	100%
B2X-68/79	Maurel & Prom Ehcopek CIP	80% 10% 10%	PDVSA	PDVSA	100%
Maulpa	Inelectra Polar	86% 14%	PDVSA	PDVSA	100%
Jusepín	Total BP	55% 45%	PDVSA	PDVSA	100%
Dación	Eni	100%	PDVSA	PDVSA	100%
Quiamare-La Ceiba	Repsol ExxonMobil	75% 25%	PDVSA	PDVSA	100%

Appendix 6 - 2006/2007 Migration Process to Joint Ventures – Former OSAs

AA (2005)	Partners	Share	Operator (2007)	Partners	Share
Petrozuata	ConocoPhillips	50%	Petroanzoátegui	PDVSA	100%
	PDVSA	50%			
Sincor	Total	47%	Petrocedeño	PDVSA	60%
	PDVSA	38%		Total	30%
	Equinor	15%		Equinor	10%
Cerro Negro	PDVSA	42%	Petromonagas	PDVSA	83%
	ExxonMobil	42%		BP	17%
	BP	17%			
Hamaca	ConocoPhillips	40%	Petropiar	PDVSA	70%
	PDVSA	30%		Chevron	30%
	Chevron	30%			
Sinovensa	CNPC	70%	Petrolera Sinovensa	CNPC	40%
	PDVSA	30%		PDVSA	60%

Appendix 7 - 2006/2007 Migration Process to Joint Ventures – Former RSCs

RS (2005)	Partners	Share	Operator (2007)	Partners	Share
Golfo de Paria Oeste	ConocoPhillips	33%	Petrosucre	PDVSA	74%
	PDVSA	35%		Eni	26%
	Eni	26%			
	OPIC	7%			
Golfo de Paria Central	ConocoPhillips	38%	Petrolera Guiria	PDVSA	64%
	Inelectra	25%		Eni	20%
	Eni	30%		Inelectra	16%
	OPIC	8%			
Golfo de Paria Este	Inelectra	100%	Petrolera Paria	PDVSA	60%
				Sinopec	32%
				Inelectra	8%
La Ceiba	ExxonMobil	50%	PDVSA	PDVSA	100%
	Petrocanada	50%			

Appendix 8 - Non-Associated Gas Blocks

Round	Year	Field	Partners	Participation
Onshore Round	2001	Yucal-Placer Sur	Total	69.50%
		Yucal-Placer Norte	Repsol	15.00%
			Otepi	10.20%
			Inelectra	5.30%

	2001	Barbacoas	Pluspetrol	100.00%
	2001	Tiznado	Pluspetrol	100.00%
	2001	Barrancas	Repsol	100.00%
	2001	Tinaco	Perez Companc	100.00%
Deltana Platform	2003	Deltana 1	PDVSA	100.00%
	2003	Deltana 2	Chevron	100.00%
	2003	Deltana 4	Statoil	100.00%
	2004	Deltana 3	Chevron ConocoPhillips	60.00% 40.00%
Rafael Urdaneta	2005	Urumaco I	Gazprom	100.00%
	2005	Urumaco III	Gazprom	100.00%
	2005	Cardon III	Chevron	100.00%
	2005	Cardón IV	Eni Repsol	50.00% 50.00%
	2005	Moruy II	Petrobras Teikoku	50.00% 50.00%
Direct Assignment	2007	Quiriquire	Repsol PDVSA	60.00% 40.00%
	2007	Copa Macoya	Inpex PDVSA	70.00% 30.00%
	2010	Punta Pescador Golfo Paria Oeste	PDVSA Eni	60.00% 40.00%
	2010	Zamaca Oeste	PDVSA Belorusneft	60.00% 40.00%
	2017	Patao Mejillones	Rosneft	100%

Appendix 9 - Alternative FX Mechanisms for Oil Companies

Effective Date	Exchange Agreement	Description	FX Rates (VEF/USD)
Dec 30, 2013	No. 24 – GO 40324	All revenues different from oil exports will be exchanged at the SICAD rate.	Official: 6.30 Alt. (SICAD): 12
Apr 4, 2014	No. 28 – GO 40378	All revenues stemming from financing agreements, financial instruments, asset sales, dividends, account receivables, services provided, and any other source different from oil exports, will be exchanged at the SICAD II rate.	Official: 6.30 Alt. (SICAD II): 49.99
Dec 30, 2014	No. 32 – GO Ext. 6167	All revenues generated by financing operations, financial instruments, and oil exports under Energy Cooperation Agreements, will be exchanged at any of the valid FX rates.	Official: 6.30 Alt. (SICAD II): 49.99
Feb 10, 2015	No. 33 – GO Ext. 6171	Creates a new alternative FX scheme, SIMADI. Rules defining which revenues can be exchanged at which rate are maintained from previous Exchange Agreements.	Official: 6.30 Alt. (SICAD II): 52.10 Alt. (SIMADI): 198.69
Mar 09, 2016	No. 35 – GO 40865	All revenues from PDVSA and its subsidiaries and from JVs can be exchanged at any of the valid rates, following guidelines by the National Government and BCV.	DIPRO: 10 Alt. (DICOM): 674.81

Appendix 10 – Current Joint Ventures equity shares and estimated production

Joint Venture	Fields	Start date[177]	Partners	Share	Country	Output (2018)[178]
Baripetrol	Rosario Colón	9/29/2006	PDVSA Tecpetrol PFC Oil & Gas[179] Perenco	60% 18% 5% 18%	Venezuela Argentina Venezuela France	6.07
Boquerón	Boquerón	11/24/2006	PDVSA Rosneft OMV	60% 27% 13%	Venezuela Russia Austria	4.82
Petroperijá	DZO	11/24/2006	PDVSA Rosneft	60% 40%	Venezuela Russia	7.75
Lagopetrol	B2X-70/80	1/11/2008	PDVSA Integra Ehcopek CIP[180]	69% 26% 3% 2%	Venezuela Argentina Venezuela Venezuela	0.42
Petroboscán	Boscán	9/29/2006	PDVSA Chevron Inepetrol	60% 39% 1%	Venezuela USA Venezuela	63.04
Petroindependiente	LL-652	9/29/2006	PDVSA Chevron	75% 25%	Venezuela USA	6.75
Petrocabimas	Cabimas Tia Juana Tierra Cabimas Este 2 Cabimas Sur	11/24/2006 3/27/2014 3/27/2014 3/27/2014	PDVSA Suelopetrol	60% 40%	Venezuela Venezuela	7.17
Petrocumarebo	Falcón Este Falcón Oeste	11/24/2006 11/24/2006	PDVSA PFC Oil & Gas	60% 40%	Venezuela Venezuela	0.48
Petrocuragua	Casma Anaco	11/24/2006	PDVSA CIP OPEN	60% 28% 12%	Venezuela Venezuela Venezuela	-
Petrodelta	Monagas Sur[181] Temblador El Isleño El Salto	10/25/2007 10/25/2007 10/25/2007 10/25/2007	PDVSA CT Energy PFC Oil & Gas	60% 32% 8%	Venezuela Venezuela Venezuela	44.77

Joint Venture	Fields	Start date	Partners	Share	Country	Output (2018)
Petroguárico	Guárico Oriental	11/24/2006	PDVSA Inpex	70% 30%	Venezuela Japan	1.72
Petrokariña	Mata	11/24/2006	PDVSA Pampa Energía[182] Jantesa	60% 35% 6%	Venezuela Argentina Venezuela	-
Petroritupano	Oritupano Leona	9/29/2006	PDVSA Pampa Energía Anadarko	60% 22% 18%	Venezuela Argentina USA	1.10
Petroven-Bras	Acema	9/29/2006	PDVSA Pampa Energía Corepli	60% 35% 6%	Venezuela Argentina Venezuela	-
Petrowayu	La Concepción	9/29/2006	PDVSA Pampa Energía Williams	60% 36% 4%	Venezuela Argentina USA	0.25
Petrolera Bielovenezolana	Guara Este Bloque X Lago Med. Oritupano Norte Ostra Bloque II Lagunillas Zamaca Oeste[183] Bloque VIII Centro Bloque XII Lagunillas	12/28/2007 12/28/2007 7/21/2009 7/21/2009 7/21/2009 12/30/2010 12/30/2010 12/30/2010	PDVSA Belorusneft	60% 40%	Venezuela Belarus	4.35
Petrolera Guiria	Golfo Paria Central	3/5/2008	PDVSA ENI Inelectra	64% 20% 16%	Venezuela Italy Venezuela	-
Petrosucre	Golfo Paria Oeste[184]	1/16/2008	PDVSA ENI	74% 26%	Venezuela Italy	11.14
Petrolera Paria	Golfo Paria Este	1/16/2008	PDVSA Sinopec Inelectra	60% 32% 8%	Venezuela China Venezuela	-
Petrolera Kaki	Kaki	1/29/2007	PDVSA Inelectra Polar	60% 23% 17%	Venezuela Venezuela Venezuela	0.02

Joint Venture	Fields	Start date	Partners	Share	Country	Output (2018)
Petrolera Indovenezolana	San Cristóbal	4/10/2008	PDVSA ONGC	60% 40%	Venezuela India	13.70
Petrolera Sino-Venezolana	Caracoles Intercampo Norte	1/29/2007 1/29/2007	PDVSA CNPC	75% 25%	Venezuela China	3.40
Petrozumano	Zumano	11/9/2007	PDVSA CNPC	60% 40%	Venezuela China	4.48
Petrolera Venangocupet	Miga y Melones Oeste	6/25/2013	PDVSA Sonangol CUPET	60% 20% 20%	Venezuela Angola Cuba	18.62
Petrolera Vencupet	Oficina Central Adas Lido-Limon	12/21/2010	PDVSA[185] CUPET	60% 40%	Venezuela Cuba	1.49
Petronado	Onado	11/24/2006	PDVSA CGC[186] Petroecuador KNOC	60% 26% 8% 6%	Venezuela Argentina Ecuador Korea	0.58
Petroquiriquire	Quiriquire Mene Grande Barua-Motatán	9/29/2006 9/29/2006 12/15/2009	PDVSA Repsol	60% 40%	Venezuela Spain	12.79
Petroregional del Lago	Urdaneta Oeste	9/29/2006	PDVSA Maurel Prom[187]	60% 40%	Venezuela France	15.34
Petrourdaneta	Mara Oeste Mara Este La Paz	4/24/2012 4/24/2012 4/24/2012	PDVSA Odebrecht	60% 40%	Venezuela Brazil	6.63
Petrowarao	Ambrosio Pedernales	9/29/2006 9/29/2006	PDVSA Perenco	60% 40%	Venezuela France	2.90
Petrozamora	Bachaquero Tierra Lagunillas Tierra Bachaquero Lago Bloque VII Ceuta Bloque III Bachaquero Bloque III Centro	4/10/2012 4/10/2012 6/3/2015 6/3/2015 6/3/2015 6/3/2015	PDVSA GPB Resources[188]	60% 40%	Venezuela Russia	49.96

Joint Venture	Fields	Start date	Partners	Share	Country	Output (2018)
Petrocedeño	Sincor	1/10/2008	PDVSA	60%	Venezuela	83.84
			Total	30%	France	
			Equinor	10%	Norway	
Petromonagas	Cerro Negro	3/5/2008	PDVSA	60%	Venezuela	77.00
			Rosneft	40%	Russia	
Petropiar	Hamaca	1/9/2008	PDVSA	70%	Venezuela	116.44
			Chevron	30%	USA	
Petrolera Sinovensa	Sinovensa	2/1/2008	PDVSA	50%	Venezuela	135.29
			CNPC	50%	China	
Petrocarabobo	Carabobo 1 Centro Norte	7/29/2010	PDVSA	71%	Venezuela	22.63
			Repsol	11%	Spain	
			ONGC	11%	India	
			IOC[189]	4%	India	
			OIL[190]	4%	India	
Petroindependencia	Carabobo 5	7/2/2010	PDVSA	60%	Venezuela	-
	Carabobo 2 Sur	7/2/2010	Chevron	34%	USA	
	Carabobo 3 Norte	7/2/2010	Inpex	3%	Japan	
			Mitsubishi	3%	Japan	
			Suelopetrol	1%	Venezuela	
Petrovictoria	Carabobo 2 Norte	10/10/2014	PDVSA	60%	Venezuela	4.69
	Carabobo 4 Oeste		Rosneft	40%	Russia	
Petromacareo	Junín 2	11/2/2010	PDVSA	60%	Venezuela	-
			Petrovietnam	40%	Vietnam	
Petrourica	Junín 4	12/21/2010	PDVSA	60%	Venezuela	-
			CNPC	40%	China	
Petrojunín	Junín 5	12/21/2010	PDVSA	60%	Venezuela	10.27
			ENI	40%	Italy	
Petromiranda	Junín 6	7/29/2010	PDVSA	60%	Venezuela	20.00
			Rosneft	32%	Russia	
			Gazprom	8%	Russia	

Endnotes

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[54] At the moment of the reform, the price established by the national budget law was 40 USD/B.

[55] A further reform in February 2013, increased the price thresholds for the exorbitant prices rates to 80 USD/B, 100 USD/B, and 110 USD/B, a ten dollar increase.

[56] We estimate government take as the percentage of all taxes compared to operating profits – the difference between price per barrel and production costs. This estimation takes the average sale price and average production costs from PDVSA's annual financial statements for each year.

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[183] Includes the fields Mapiri, Mapiri Este, Mapiri Central, Soto Este, Soto Norte, and La Ceibita.

[184] Includes the Corocoro field.

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