The Future of Venezuela's Oil Industry

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ABOUT THIS PAPER

Throughout much of developed world, there is a consensus that concern over climate change is leading to a rapid downturn in petroleum use and that petroleum will likely have a rapidly declining role in the world's energy mix over the next 30 years. However, a rapid energy transition to a world no longer reliant on fossil fuels represents a formidable challenge and a high likelihood remains, especially in the developing world, that petroleum's important and large contribution to the world energy mix will not be so easily displaced. Recent EIA forecasts show that world oil and gas demand has reverted to trend. Supply requirements for the end of 2022 are likely to exceed 100 million barrels/day, a remarkable recovery from a decline in liquids demands of over 15 million barrels a day in 2020 from the Covid-19 pandemic. Although Venezuelan oil production has been constrained by both technical mismanagement and sanctions, the size of its reserve base documents its potentially important role in meeting future world oil demand.

The timing of Venezuela's petroleum future depends on whether it can enter the world oil market under traditional commercial conditions. On June 25, 2021, the U.S., Canada, and the E.U. issued a joint communiqué that made clear that a decision regarding the timing and specifics of the sanctions on Venezuela remains the primary determining factor on when and if Venezuela can play a larger role in the world oil market.

Even if Venezuela were somehow to find its way free of sanctions, the road back to higher production will require massive capital investment. Venezuela, which produced over 3 million barrels in day in the 1970s, is now at only 600,000 barrels per day. The authors estimate that the level of investment and amount of time required to rehabilitate the production potential of Venezuela would approach $30 billion USD in two stages:

Stage 1 – Pre-sanctions recovery: An investment of $7-9 billion over 2-3 years to get back to production prevalent before sanctions started in 2017 (about 2 million barrels/day).

Stage 2 – Post-recovery: An investment of an additional $20 billion/year for 2-3 years. These investments would take 4-5 years to yield additional production. This would require investment into offshore and underdeveloped onshore projects to bring them up to full production capacity. With proper investment, Venezuela can sustain a production output of approximately 2.5 million b/d over the next 20-30 years.

The authors provide an overview of Venezuela's production potential, and evaluate the technical obstacles that must be addressed to restore Venezuelan oil production.

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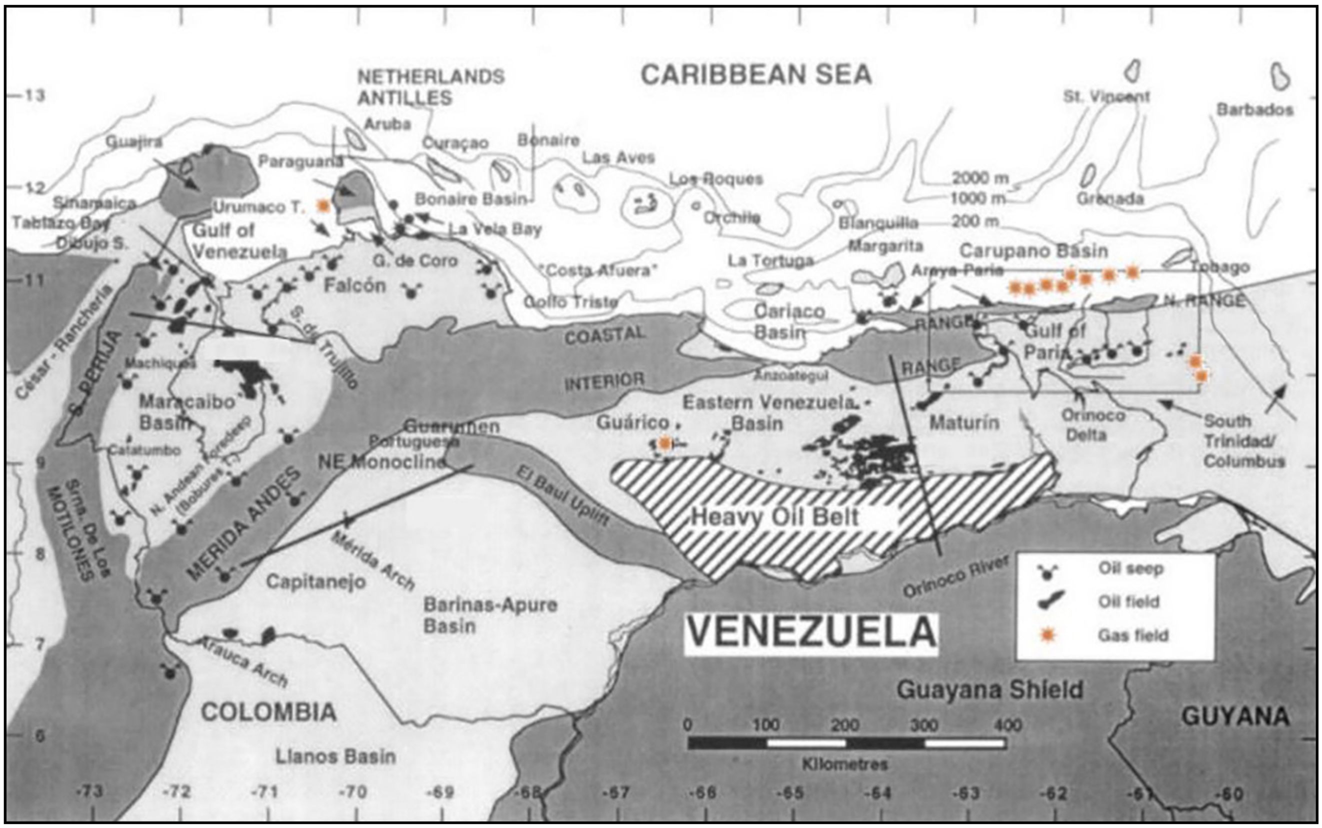
A QUICK LOOK AT THE PAST

Venezuela celebrated its 100th year of commercial oil development in 2010. Since its early beginnings in the 1910s and through 1975, Venezuela's oil industry was operated by private companies, led by the legendary names of the times: Shell, Exxon, Chevron, Mobil, Texaco, Gulf Oil, Sinclair, and Phillips, to mention a few. The first major oil discovery was the Mene Grande field in the Western (Maracaibo) basin, in 1914. Since then and through 1917, several more major fields were discovered, including the fabled giant Bolivar Coastal Field, all in western Venezuela. These early discoveries, together with the emblematic blowout of the Barroso No. 2 well in Cabimas in 1922, signaled the international importance of Venezuela's oil production potential.

Figure 1
Venezuelan Oil and Gas Fields



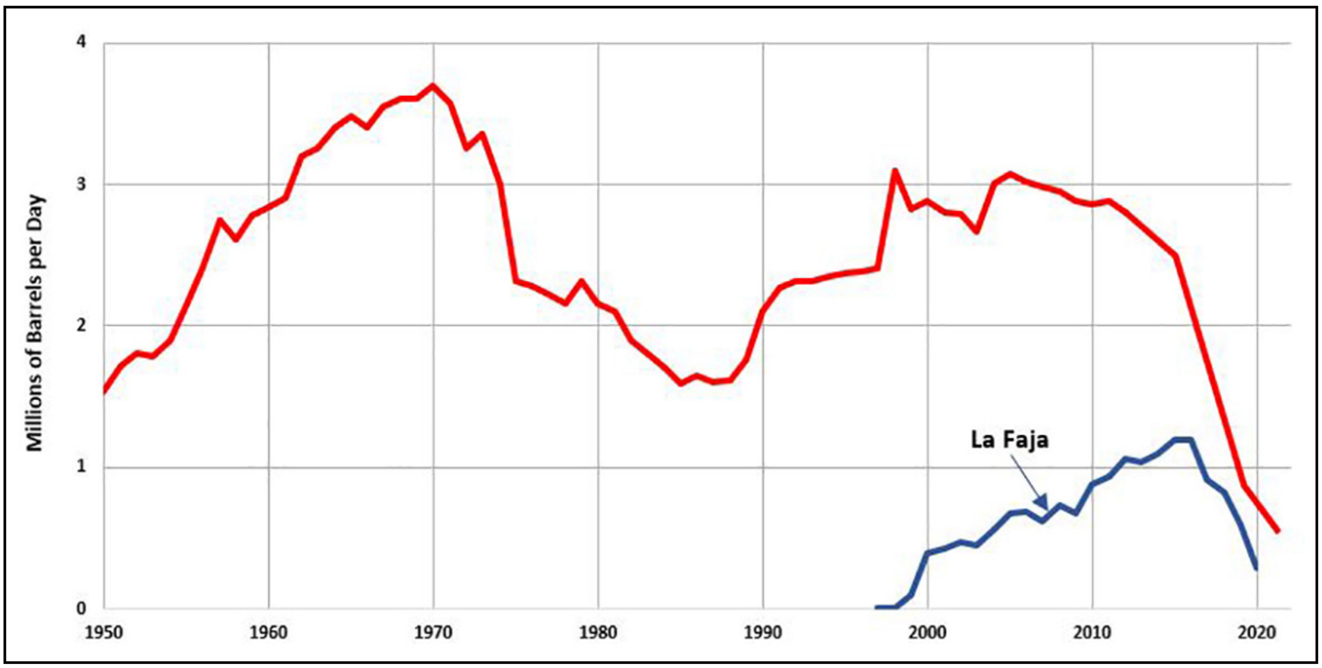
Source: USGS, Ref. 2.

*The main basins, arches, and uplifts of Venezuela, together with the distribution of the main oil and gas fields and the locations of seeps. Bathymetric contours at 200, 1,000, and 2,000m indicate the form of the continental shelf.

In the Eastern (Oriente) basin, commercial oil production began in 1937 with the discovery of the Oficina field. By the end of the decade, Venezuela was producing 560 thousand b/d (kb/d) and had become the third leading oil producer in the world, behind the U.S. and the Soviet Union. Venezuela was a staunch supporter of the Allied efforts during WWII. Production kept growing, reaching a milestone of one million b/d (mb/d) by the end of 1945, finally reaching its peak of 3.7 mb/d in 1970, **Fig. 2.**

Production subsequently declined to a low of 1.68 mb/d in 1985. But then three giant fields were discovered in the Eastern basin in the late 1980s, and production started growing again, reaching a high of 3.1 mb/d in the late 1990s, after which it continued its decline falling to 2.5 mb/d by 2015. Output has since dropped abruptly reaching 877 kb/d in 2019 and is currently (March 2021) about 538 kb/d. Over the last five years production has been marred by strong political events which include U.S. economic sanctions that went into effect in 2017.

Figure 2
Venezuela's Oil Production Since the 1950s

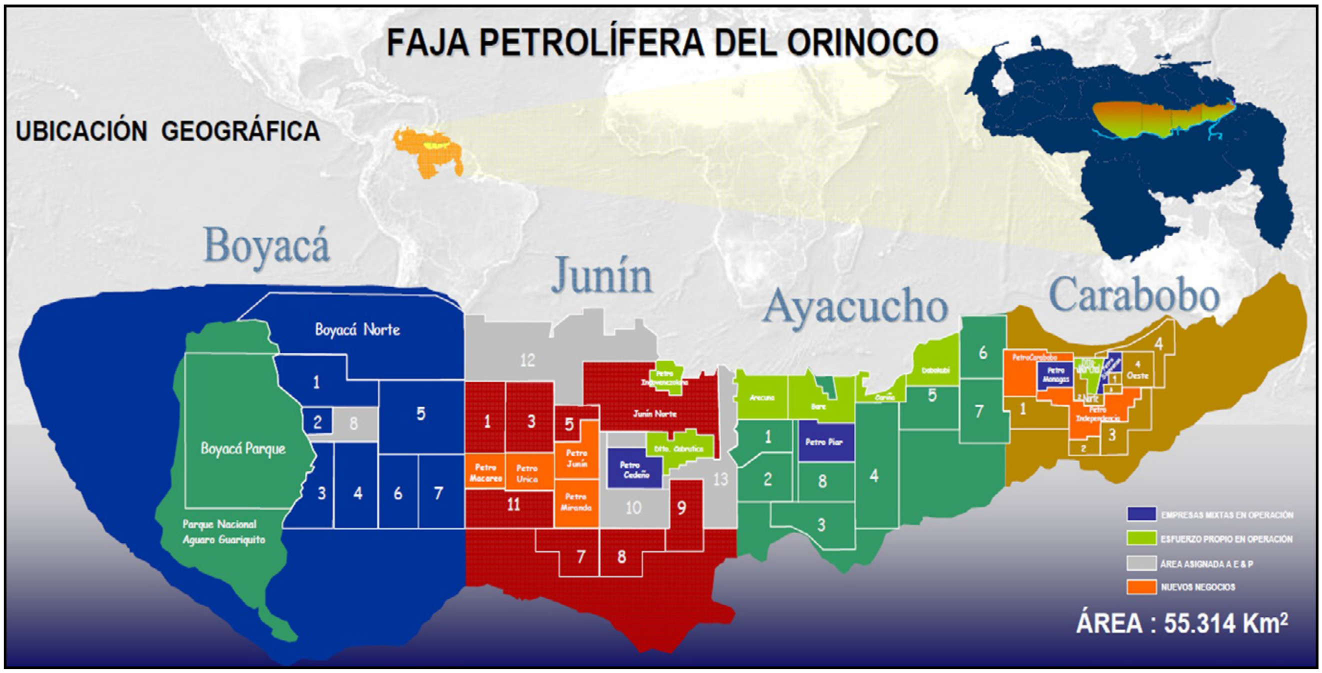


Source: PODE, EIA

The country officially nationalized its oil industry on January 1, 1976, and ever since, PdVSA has been its main operator. This was not an abrupt process, but a smooth turnover agreed upon by both sides. The process, in effect, started in 1958 when the Venezuelan government announced its policy of 'no more new blocks' for private investors. Up through 1956, periodic auctions of blocks were the accepted rule. Successive administrations approved additional legislation conducive to nationalization. Interestingly,1957 was the last year of giant oil discoveries – the Centro, Lama and Lamar fields – for the next 24 years! By 1985, oil production had dropped to a low of 1.68 million b/d. Then, PdVSA made a very timely discovery of a complex of three deep (4,100 m), highly over-pressured (0.83 psi/ft) giant oil fields: El Furrial, Santa Barbara deep and El Carito – the El Furrial trend – in the very productive Maturin sub-basin. This provided an injection of 8 billion barrels (Bbo) of new reserves. This sub-basin still provides the country with the largest production of different oil streams with gravities higher than 30°API. At that time, the country's output began expanding again. Production of the three giants peaked at 1.2 million b/d in 2006, 40% of the country's production at the time. By 2017 their output had plunged to 575,000 b/d.

In 1994, Venezuela also opened a new phase of international participation, awarding blocks of marginal fields including the mature giant Boscan field, exploration blocks offshore, and development of its now well-known Orinoco Heavy Oil Belt, aka the Faja. This is Venezuela's golden goose, which holds about 1.3 trillion barrels of oil-in-place (USGS, 2009) – the world's largest extra-heavy (≤10 °API) petroleum deposit (**Fig. 3**). It was divided into four blocks, from west to east: Machete, Zuata, Hamaca, and Cerro Negro, portions of which were farmed out to four select international operators: ConocoPhillips, Sincor, Ameriven, and ExxonMobil. Sincor was an alliance between Total and Statoil. Ameriven was an alliance between ChevronTexaco and ConocoPhillips. The names of the blocks were later changed to Boyacá, Junín, Ayacucho, and Carabobo, respectively, in the same sequence. Less than 6% of the Faja's oil resources lie in the Boyacá block.

Figure 3
The Orinoco Oil Belt



Source: PdVSA

The four operators designed and built upgraders to extract the raw extra heavy (≤ 10 °API) crude with a diluent (naphtha) (naphtha) that brings it up to a lighter (26-32°API), sweeter (0.07%S) synthetic oil known as syncrude, which is then sent to the refineries. There, the upgraders convert the extra heavy crude into an oil of greater commercial value, extracting marketable by-products such as sulfur, coke, and LPG and in some cases yielding other hydrocarbon streams. The upgraders were all congregated in Jose, a port complex located on the north coast some 200 to 300 km from the oil fields. They were managed by the corresponding foreign partners in the different JVs.

By 2003, total production from these projects had reached 500,000 b/d of synthetic crude – close to the capacity at the time of the four upgraders which was later increased to 600,000 b/d in 2005 – and the country's production had grown to a little over 3 million b/d. Then in 2007 the government changed the equity distribution conditions of the international mixed-ownership companies that owned the upgraders, with the stated objective 'to homogenize their existing contractual terms and conditions with those of the new 2001 Hydrocarbon Law'. This stipulates higher royalty and income tax rates and requires that PdVSA's holdings be a minimum of 60% equity in any project versus 30-50 % in the 35-year duration existing franchises. Consequently, in 2009, new JVs were being formed with major partners such as BP, Chevron, CNPC, ENI, ONGC, Petronas, Repsol, Rosneft, Statoil, and Total. Production from the Faja continued growing reaching 1.2 million b/d by 2015 and fluctuating around that level through 2017. Subsequently, production has been dropping for multiple reasons, reaching below 300,000 b/d in 2020. To date, the Faja has produced about 6 Bbo which includes some diluent. There are 61 operating fields and 2,600 active wells. This will be discussed more extensively later on in this report.

An essential part of Venezuela's oil history are several technological breakthroughs that were developed there, as was the more recent and newer Faja technology. Included in these are Schlumberger's resistivity well log that was tested in 1929 in the Bolivar Coastal fields; this tool was the industry's first that allowed geologists to identify subsurface formations. There is also Shell's steam drive pilot in the Mene Grande field in 1959, which led to the development of the modern-day steam soak process for heavy oils. In more recent years, the extra-heavy oil production from the Faja and nearby low API gravity fields stimulated major technological developments related to water-in-oil stable emulsions, heavy oil core flow with water rings, extra-heavy oil lifting with progressing cavity pumps driven by electric downhole motors, elastomer advances for these pumps, new developments in metal-metal progressing cavity pumps for massive use in future steam-operated production wells, and many others.

Over the over 100 years of Venezuela's traditional oil development, about 75 billion barrels of producible reserves have been discovered in some 320 oil fields, from which 65 billion barrels have been produced so far. More than 55,000 production/development wells and 5,945 exploration wells have been drilled, and as of 2014, 15,000 wells were active. Included in those 320 oil fields are 28 giant oil fields – 13 in the Western Venezuela basin and 15 in the Eastern Venezuela basin – that account for more than three-quarters of the traditional reserves discovered. Venezuela boasts a super giant, the Tia Juana field with an OIP of 64 Bbo, located in the Western basin. **Table 1** (see page 6) offers a short description of these giant fields. Giant oil fields are the foundation of a solid oil industry. There are two giants that deserve a special mention. The El Carito field is a unique retrograde condensate field. These fields require early high-pressure gas injection for maximum liquid recovery. The Ceuta field is a HPHT field discovered 40 years ago. Its reservoirs are deep (5,000 m) and high-pressured (10,000 psi) making for complex production operations. Modern-day technology will certainly enhance its recovery factor.

Of the 66 billion barrels of reserves (EUR) discovered with the giant oil fields the split between the Western and Eastern basins is roughly 70:30. The only offshore oil field discovered to date is Corocoro, located in shallow waters of the Gulf of Paria, with recoverable reserves of 210 million barrels. It was discovered by ConocoPhilips in 1999, production began in 2007 ramping up to 37,000 b/d and continued at that level through 2019 when it was closed in the wake of U.S. sanctions. In this report we make a distinction between traditional oil and Faja. The above numbers refer to traditional oil fields. The Faja is discussed separately in the next section. Faja production effectively started after 2000 when the upgraders began operations.

Regarding natural gas, although Venezuela produces significant volumes of gas (7.7 bcfd in 20150 which declines when oil production declines, 90% of the produced gas is associated gas. The country consumes nearly 33%, about 40% is reinjected in reservoirs to sustain pressure and increase oil recovery, and the remainder is flared, lost, or simply not gathered and therefore wasted. In the past some gas was imported by pipeline from Colombia to cover consumption demands in western Venezuela, but this project was discontinued in 2016. Up until 1980, Venezuela had discovered only one giant gas field – Yucal-Placer in 1948 – located in the Eastern basin. In 1979/83 four new gas giants – Mejillones, Patao, Dragon, Rio Caribe – were discovered by PdVSA, offshore in the Caribbean Sea in water depths of 120 meters. Mejillones and Patao were licensed to Rosneft for development in 2017 but have not yet produced significant volumes. The Dragon and Rio Caribe fields are also awaiting development. In 1983, another giant gas field, Loran, was discovered by PdVSA in the shallow waters (91 m) of the Atlantic Ocean. It is a cross-border field with Trinidad. Loran-Manatee has been jointly producing since 2013.

In an attempt to stimulate exploration efforts for much-needed non-associated gas, Venezuela adopted the Gas Hydrocarbon Law in 1999. It allows private operators to own 100% of non-associated gas projects and offers royalty and income tax rates lower than those for oil. In 2009, the giant Perla field was discovered in water depths of 60 meters in the Gulf of Venezuela, off the coast of Cardon. Perla is the largest of Venezuela's six gas giants with a huge 17 tcf of gas in-place; the operator is ENI. Production began in 2015 and the field is expected to eventually produce 1.2 bcfd. A total of just 45 tcf of gas resources have been discovered so far but there is geologic evidence of much more to be found offshore.

Venezuela's traditional crude oil is heavy-sour, averaging 22.2°API with 2.06% sulfur, which impacts both production costs and market prices. As a result, recovery factors are low, averaging about 17%, leaving behind huge quantities – up to 94% in some cases – of discovered oil in the ground. The average reported recovery factor for the giant fields is about 20%. Most of its major oil fields are very mature and new oil discoveries have been small, averaging about 185 million barrels per year of recoverable oil over the last two decades. In contrast, traditional oil production in 2015 was over 475 million barrels and much higher in previous years. This absurdly high ratio of production to discoveries is unsustainable, conducive to extremely high decline rates and a swift depletion of existing reserves of about 10 billion barrels.

This overview was intended to provide a snapshot of Venezuela's upstream oil industry and its challenges. The objective of this report is to take a technological look at three themes we consider critical for a valuable economic future of the country's oil industry: the Faja, the mature fields, and exploration for both oil and gas. Traditional oil reserves are low and fast-declining. Further, any large-scale application of advanced EOR technologies in the Faja will require huge amounts of natural gas and treated water; for steam injection roughly 0.2 barrels of water for every barrel of oil produced are required. Venezuela's gas production and consumption are already barely in the balance. **Table 1** underscores the paucity of gas amid an abundance of heavy and light oils.

Table 1
Giant Oil and Gas Fields of Venezuela

Field	Discovery Year	Discovery Company	Basin	Age	API	OIP, Bbo	EUR,mbo	GIP,tcf
Mene Grande	1914	Shell	Western	T	19	2.9	840	
Cabimas	1917	Shell	Western	T	22	2.9	660	
La Paz	1925	Shell	Western	K	33	4.6	980	
Quiriquire	1925	Exxon	Eastern	T	17	3.8	810	
Lagunillas	1926	Exxon	Western	T	18	43.6	9,200	
Tia Juana*	1926	Exxon	Western	T K	23	63.6	12,100	
Bachaquero	1930	Shell	Western	T	17	31.2	7,600	
Orocual	1933	Exxon	Eastern	T K	17	4.9	817	
Jusepin	1938	Exxon	Eastern	T	31	2.1	537	
Oficina	1937	Gulf Oil	Eastern	T	27	2.5	560	
Sta Barbara	1941/88	PdVSA	Eastern	T K	31	8.9	3,014	
Sta Rosa	1941	Gulf Oil	Eastern	T K	43	2.6	750	
Guara	1942	Gulf Oil	Eastern	T	24	3.4	770	
Mulata	1942	Exxon	Eastern	T K	29	5.2	2,654	
Dacion	1945	Gulf Oil	Eastern	T	20	1.8	550	
Nipa	1945	Gulf Oil	Eastern	T	29	2.0	502	
Mara	1945	Shell	Western	T K	24	3.9	720	
Boscan	1946	Chevron	Western	T	10	35.3	2,750	
Yucal-Placer	1948	Las Mercedes	Eastern	T				10
Chimire R	1948	Gulf Oil	Eastern	T	33	1.8	585	
Mata	1954	Gulf Oil	Eastern	T	28	4.2	880	
Centro	1957	Exxon	Western	T K	35	8.6	1,100	
Urdaneta	1955	Shell	Western	T K	14	27.3	2,900	
Oritupano	1955	Gulf Oil	Eastern	T	18	2.6	677	
Lama	1957	Superior Oil	Western	T K	32	10.6	3,670	
Lamar	1957	Shell	Western	T K	35	5.1	2,000	
Patao	1979	PdVSA	Carib Sea	T				5
Mejillones	1980	PdVSA	Carib Sea	T				6
Ceuta	1981	PdVSA	Western	T K	28	14.9	3,463	
Dragon	1982	PdVSA	Carib Sea	T				4
Rio Caribe	1983	PdVSA	Carib Sea	T				3
Loran	1983	PdVSA	Atlantic	T				7
El Furrial	1986	PdVSA	Eastern	T K	27	8.4	4,325	
El Carito	1988	PdVSA	Eastern	T K	28	1.1	684	
Perla	2009	ENI	Gulf Vzla.	T				17
				TOTAL		**310**	**66,000**	**52**

Source: PODE, Company reports, Publications.

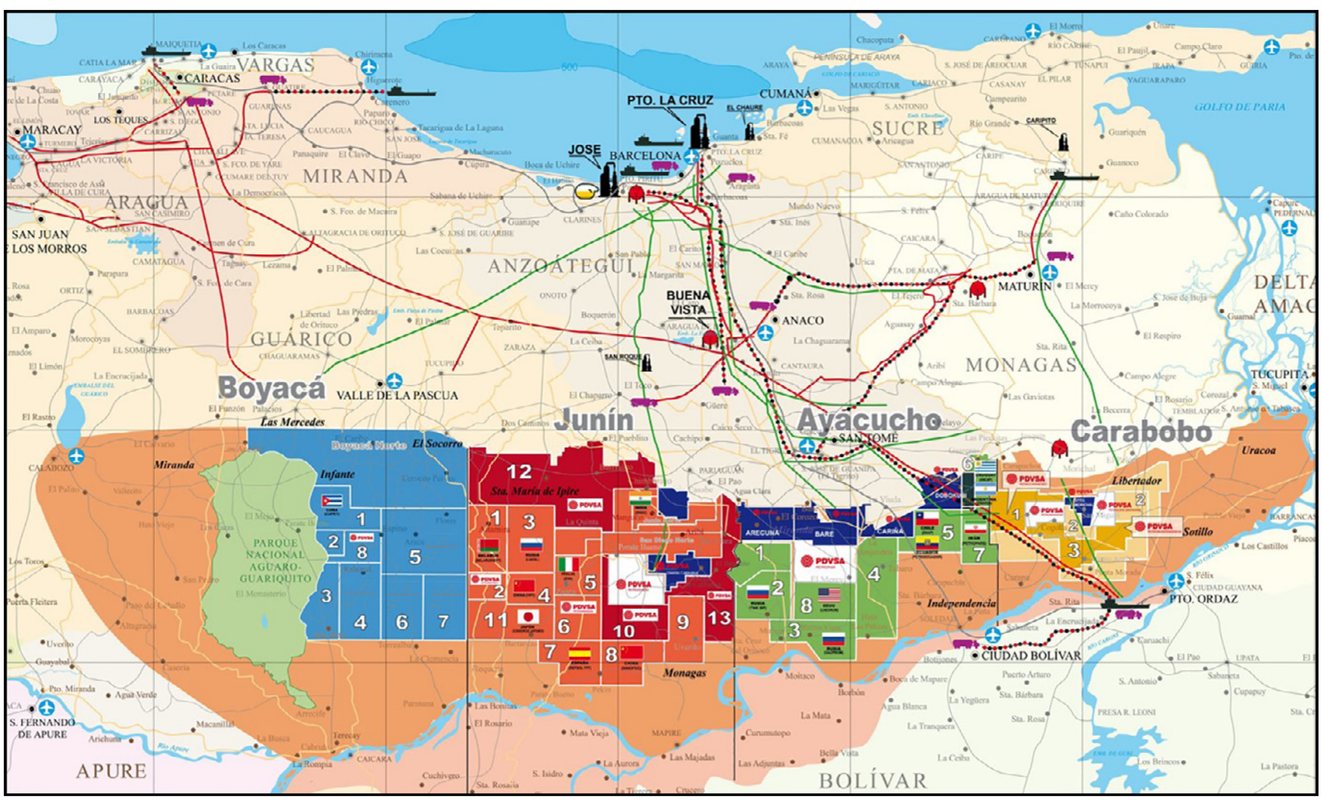
Giant: EUR ≤500 mbo or 3 tcf. * Super giant: EUR ≥10 Bbo. Red = Gas. T = Tertiary; K = Cretaceous.

THE ORINOCO OIL BELT

The Orinoco Oil Belt is considered to be the largest hydrocarbon accumulation in the world. It is a massive body of mostly Cenozoic (Miocene) sediments, 650 km X 70 km, that lie on the southern border of the Eastern basin, north of the Orinoco River, **Fig. 4**. The Belt is estimated to contain about 1.3 trillion barrels of extra-heavy (7-13° API gravity) crude oil with a low average GOR (gas-oil-ratio) of 110 scf/b that together with high viscosities contribute to very low recovery factors. Viscosity at reservoir conditions of the Orinoco's shallower extra-heavy oils runs up to 5,000 cp, which is syrup-like in viscosity compared to water (1-5 cp) or light (45°API) crudes of 3 cp. Canadian extra-heavy oils have viscosities of 10,000 cp and more; it runs as high as 100,000 cp in their well circulated Cold Lake project.

Cold production (without any steam injection) has been the only methodology used in the Faja and the four original projects assumed recovery factors of 7-9 percent. In a comparable analog, the Boscan field, with extra-heavy oils of viscosities < 500 cp, has also been cold-produced for over 70 years. In the real world, both the Boscan field and the Faja projects have similar recovery factors around 5-6%, leaving in the ground a huge 95 % of the oil in place. Reservoir depths in the Boscan field are in the range of 1,500-2,900 meters, which are generally beyond the limits for standard steam technology. On the other hand, the Orinoco reservoirs are on the average 50 meters thick, at depths less than 1,200 meters. And these two characteristics are favorable for steam injection which lowers the oil viscosity and bolsters extraction rates. Steam injection is a worldwide proven technique to enhance heavy oil recovery and can increase the recovery factor by as much as 20% (Ref. 6). The steam soak technique has been typical practice in the Bolivar Coastal fields (Bachaquero, Lagunillas and Tia Juana), which together contain nearly 140 Bbo of oil-in-place (OIP) with viscosities in the range of 100–10,000 cp. The achieved recovery factor there has been 20%.

Figure 4
The Faja, Pipelines and JOSE Location



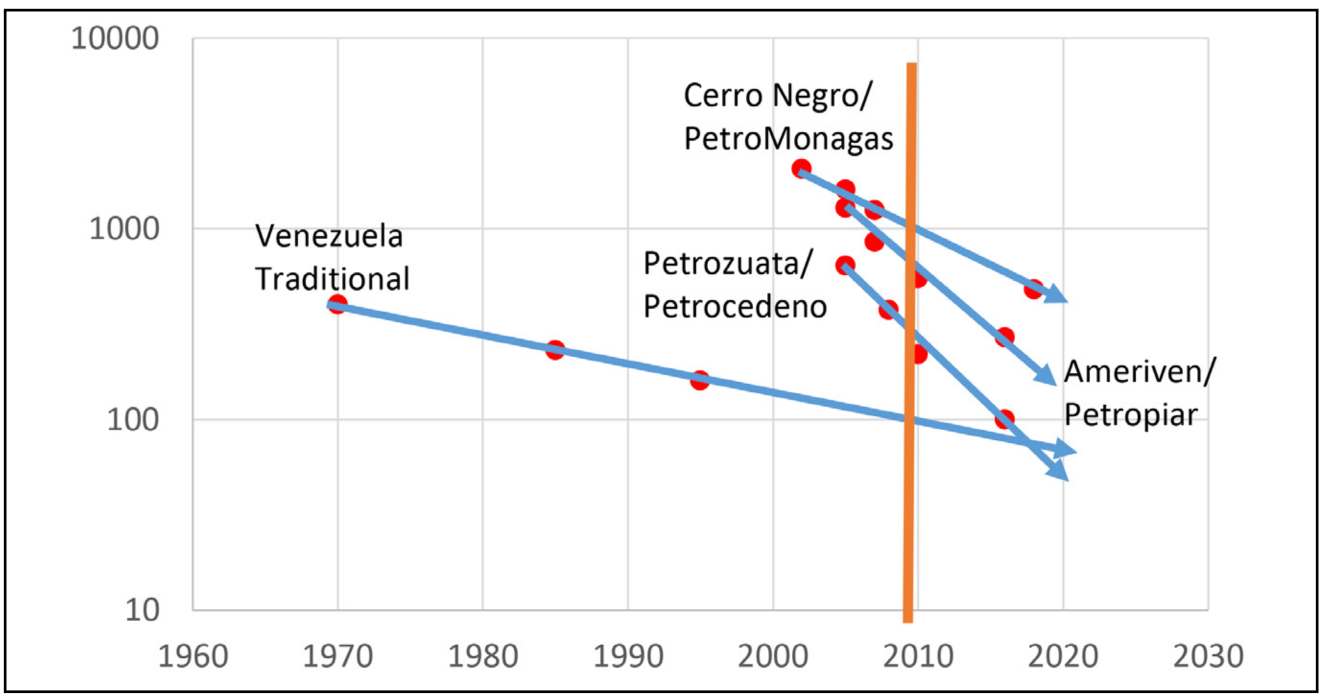
Source: PdVSA

Over the last two decades, the Faja has been cold-produced by a variety of international firms using different drilling and completion techniques to maximize initial well production rates and recoverable reserves. In the very early days, initial well rates hovered around 200 b/d, and today they are around 1,400 b/d. Present operating practice has now settled around horizontal wells with extensions of 1,000 – 2,000 meters as the preferred procedure. The Faja area has excellent reservoir characteristics (Ref. 7): net sand thicknesses of 6–100 m, high porosities of 28-34%, and very high permeabilities up to 30 darcys. Heterogeneities are also high with N/G (net to gross) values of 0.25 in the thin sands; 30-40% of the sands are less than 6 m thick. High extraction rates are accomplished using special downhole progressing cavity electric pumps. The extra heavy crude produced is then mixed with diluent just downstream of the wellheads to facilitate transport to the upgrader facilities located more than 200 km away in JOSE. This technical landscape demands sophisticated reservoir management for cold production and more so for any possible EOR technologies.

In 2010, the administration announced an aggressive development plan for the Faja – *Siembra Petrolera (Sowing the Oil Crop)* – with the object of increasing production capacity to 1.3 million b/d. The Faja's four major sectors (**Fig. 4**) were further divided into 29 blocks of approximately 500 square km – similar in size to the average of the four original projects – and negotiated as joint ventures with many major foreign companies through 2030. PdVSA always holds 60%. By 2013, the Faja's production capacity had increased to 1.3 million b/d. Production has fluctuated around 1.2 mb/d through 2017 (**Fig. 2**) but has since dropped to less than 300,000 b/d in 2020 for non-technical reasons.

Now it is evident that cold production in the Faja will be around for a long time, at least through 2030, so it would be useful to assess its effectiveness across some of the major projects. To this end we have conducted a field well-productivity analysis (Ref. 8) of the following projects: Petrozuata (now Petrocedeno), Cerro Negro (Petromonagas) and Ameriven (Petropiar). The starting point for the 'new' projects was post 2010 which is displayed with a red line in **Fig. 5**. The three different field well-productivity profiles go from their year of peak well-productivity to the present. For comparison, the profile of Venezuela's traditional oil fields – yearly production rate / number of active wells – is shown.

Figure 5
Field Well-Productivity in FAJA (b/d/well)



Source: PdVSA

Although these charts are akin to field production profiles, field well-productivity couples production to the number of producing wells. This offers a distinctive advantage in that the profiles are straight lines in log-linear space after decline sets in. This feature, as a supplement, provides a comparative quick look at decline behavior mirrored by the straight-line slopes of the profiles. Case in point are the accelerated decline rates of the extra-heavy oil projects versus traditional fields – up to 7.8%/year for Petrozuata versus 2.5%/year for traditional oil fields, a ratio of 3 to 1. The initial well-productivity values on the chart reflect the well rates when field production was at its peak. In the case of traditional fields, peak well-productivity was just 400 b/d/well in 1970, had dropped to 160 b/d/well by 1995, and is now less than 100 b/d/well. The modern drilling and completion techniques used in the Faja provide initial well production values as high as 2,000 b/d in the Cerro Negro/Petromonagas project. It was not possible to analyze new projects like Petrocarabobo that effectively started with its upgrader around 2013 and is still in an early stage of a stable/continuous operation. Nonetheless, it has shown early initial field well-productivities of 1,500 b/d.

Even for the best projects like Petromonagas, its well-productivity decline graph shows it will drop to 80 b/d/well by 2030 which would require 2,400 wells to keep the upgrader running at capacity! In the case of the Petrozuata project, its well-productivity will decline to 60 b/d/well over the next five years. All said, decline rates for the Faja are high and just to maintain outputs to meet the upgraders' capacities requires increasingly high investments in constantly drilling/completing additional wells which cost about $5-7 million each; the range derives from different well depths and lateral lengths among other factors. It is important to point out that from the decline curves in **Fig. 5**, the early wells drilled, for example in Petrozuata, are expected to produce on average 4.5 million barrels of oil each. In the case of Cerro Negro, the expected total production or reserves per well is 15 million barrels. Huge differences. Because of decline, in-fill wells drilled five years after field peak for example will have initial well-productivities of 374 b/d for Petrozuata and 1,300 b/d for Cerro Negro; and their expected reserves will also be different: 1.8 million barrels for Petrozuata and 10 million barrels for Cerro Negro.

As we close this section on the Faja, it is convenient to summarize the issues or important-critical areas that have been noted over its history and development from early production that later evolved through the primary projects whose productivity is shown in **Fig. 5**. It is clear that such a major deposit, because of its huge OIP (over 1.3 trillion barrels), large geographic extension, and variable rock, fluid, depth variations, and limited cumulative production to date, has a significant future production potential. Of course, this is provided that the relevant issues are handled correctly on a timely basis. The review of the ongoing six major projects (four associated to upgraders and two depending on diluted cold production) will provide the required hard data to define such critical issues.

Regarding the issues discussed herewith, some are technical, but in the end, all have economic impact or elements. Thus far, the road has been the simplest (although not easy by any means): natural flow from the reservoir to the wells and all kinds of improved artificial lifting (with and without dilution) but certainly with dilution for surface unheated transport. The natural reservoir energy – solution gas drive – has been the driving force despite the low GORs. Added energy through massive steam operations or other enhanced mobility processes has been piloted successfully in Petropiar proving the concept but has not been widely used up to now.

It is clear that if such thermal strategy is not followed in the future for the unexploited areas, recoveries will not exceed 4-5% of OIP for cold recovery. Surface handling options under both cold and thermal production strategies must be carefully planned, including diluent supply to the field, internal field diluent distribution and blending, fuel gas, and freshwater supplies. It is then obvious that the future must be planned with great detail and depth of analysis from the onset.

Last, but certainly not least, the complexity of the different investment-operational options leads to uncertainty levels that undoubtedly will require planned periodic project reviews. The government should carefully analyze alternatives for potential fiscal regimes such as to maximize not the government take in percentage terms, but the overall economic and integral benefit to the nation, including employment, economic activity, technology, and cash-flow. The starting point of the fiscal regime must be selected with extreme accuracy to promote the investment, and then followed-up with periodic reviews and adjustments based on comprehensive principles of investment agreed upon by all parties. If this is not built into the contractual operating terms, the levels of initial investment will not be secured, simply because the timeframe required to recover the massive investments will approach the contract 25- to 30-year limit and be overrun by the uncertainty of the capital recovery and the profitability indices. More critically, even if initial investment proceeds, given the nature of staged developments, future investment and development runs the risk of being halted if the economic conditions deteriorate for whatever factor.

It would appear that programmed mandatory review cycles will be in the 3- to 5-year range so that adjustments can be made in order that investment-recovery and minimum guaranteed profitability margins are offered to the investors and to the government, so that both sides can be comfortable with a risk-controlled 25-to 30-year scenario. If this is not recognized early on, Faja development will not occur since the massive investment levels are only manageable by a very small number of worldwide operators. If a flexible type-contract including mandatory periodic reviews is successfully executed, the takes by the government and the operator-investor can be handled on-time to react to the unexpected variation in oil prices, production forecasts, cost increases and economic indicators for capital recovery and profitability. Ultimately, any large-scale increase in production potential will have to come with multibillion dollar investments, of the order of $5.7 billion for a typical project of 100,000 b/d of syncrude backed by 120,000 b/d of crude oil production.

REVITALIZING MATURE OIL FIELDS

Venezuela has been a major oil producing country since the 1920s. Over the next ten decades some 450 billion barrels of traditional oil-in-place have been discovered with over 320 oil fields. Production peaked at 3.7 million b/d in 1970, thereafter declining continuously over the next two decades when three new giant fields were discovered (see **Table 1**) and provided production growth for about ten years, touching a high of 3.1 million b/d in the late 1990s. Thereafter, output has been on a severe decline reaching a paltry 250,000 b/d in 2020 (see **Fig. 2**), accelerated further by U.S. sanctions that kicked-in in 2017. This discussion on mature fields is centered on traditional oil fields beyond the Faja.

Virtually all of Venezuela's major oil fields are older than 60 years; and the rest are more than 20 years old. Realizing this fact, in 1992 PdVSA opened up to private investment, via service contracts, for the first time since nationalization in 1976. The objective was to revive 55 inactive fields holding a total of 357-1,100 million barrels of reserves, reworking existing wells, drilling new ones, and some exploration with advanced seismic to uncover reservoirs that may have been missed when the field was first drilled. The bidding was successful and included majors such as Shell, Chevron, CNPC, Total, ENI, and smaller companies.

Obviously, revitalizing such old fields is quite a challenge and cannot start until the country is past the period of sanctions. The object of this study is to provide a framework of what we visualize can be done, first to restore production as soon as possible to pre-sanctions level and secondly to revitalize production growth with adequate production infrastructure and implementing technologies proven in the Faja such as horizontal wells, special downhole pumps, and other pertinent IOR methods to increase recovery factors over a 5 to 10-year period. Some have estimated that an investment of less than $10 billion should get us through the restoration period. Success here is vital because it will determine the feasibility of more intensive investments for the revitalization phase. In short, we need to make a step-change in the decline curve for traditional fields shown in **Fig. 5**. Over the longer term, exploration is the only way of generating fresh reserves and production. This is discussed in the following section.

It is outside the scope of this study to analyze even briefly the reservoir/production engineering aspects of the 100 mature fields summarized in Table 2. Mature fields that are into the 4th quarter of their economic life, as is the case here, have to be analyzed individually and in great detail when designing an operations strategy. Nevertheless, a macro perspective of them can provide some interesting observations. The Top 100 oil fields are listed by size (OIP) and grouped by basin. The first observation is that that their size distribution declines sharply, from an OIP of 64 Bbo (Tia Juana) to less than 100 Bbo across the entire list. This situation is more evident for fields in the Western basin for which the OIP drops from 64 Bbo to 100 mbo across just 22 fields.

By basin, 267 Bbo of oil have been discovered in the Western basin versus 92 Bbo in the Eastern basin and 5.6 Bbo in the Barinas-Apure basin. Excluded from **Table 2** are four major extra-heavy oil fields: Melones, Morichal, Jobo, and El Salto with a total OIP of 40 Bbo. They are border fields of the Faja and are handled operationally as part of it; a few smaller fields with oils of ≤ 13° API gravity have also been omitted. In brief, the best 100 fields displayed account for over 80 % of all traditional oil discovered in 320 plus fields. They provide the focus of any strategy to revitalize the country's production.

Additionally included in **Table 2** are the volumetrically weighted API gravities of the oils in the different fields. We have also identified those fields that have been subjected to fluid injection projects, some with multiple projects, 62 in all, consisting of natural gas, water, and steam with goals of pressure maintenance and boosting recovery factors. In addition, there are two projects of miscible gas injection in the Chimire R field and Boqueron fields. The increase in recovery factor for each field may readily be estimated by comparing the EUR of the field before any injection project was undertaken (column 6) with its current cumulative production (column 7). Let us take a look at the El Furrial field which has been subjected to injection of gas and water. Its EUR was initially 1,140 million barrels and its cumulative production to date (2020) is 3,345 million barrels which corresponds to a high recovery factor of 40%. Based on the project's superb performance, this field is now expected to produce an additional 980 million barrels for an excellent recovery factor of 52%. Venezuela has a well and good experience with IOR and EOR projects.

Overall, the metrics of **Table 2** indicate that for the 100 fields there is an expectancy of recovering 71 Bbo of which 54 Bbo have been produced so far. The expected recovery factor is 19.4%, which is characteristic for the mix of oils discovered. An aggressive/successful IOR/EOR effort would at best produce an additional 5% or 18 Bbo of fresh reserves. Rehabilitating very mature fields is costly (EOR capex runs about $3-15 per barrel), risky, and requires special/intensive care for each 'patient'. Independent oil companies are the ones mostly attracted to these challenges. Service contracts are not adaptable nor appropriate for these lofty objectives. To jump-start a program of this kind requires tax incentives and contracts that specifically address the development of mature fields where payouts are typically drawn out for 5-8 years. Major investors in energy projects worldwide will not allocate investment funds to projects that do not meet reasonable conditions for capital recovery and fair-market capital yields.

At this point it would be helpful to take a look at the historic performance, before and after, of three giant fields of the 55 marginal fields that were farmed out in the early 1990s under the Service contract umbrella. A couple of these were later converted to JVs with PdVSA holding 60%. For this particular analysis, we have chosen the following fields: Boscan (Chevron), Dacion (ENI), and Yucal-Placer (Total).

Table 2
Top 100 Traditional Oil Fields by Size (OIP)

Field	Discovery Year	IOR / EOR Injected Fluids	°API	OIP (mbo)	EUR (mbo)	Cumulative Produced Oil (mbo)	Current RF (%)
Western Basin							
Tía Juana	1926	Water;Gas;Steam	23.3	63623	12123	12958	20.4%
Lagunillas	1926	Water;Gas;Steam	18.8	43577	9219	7441	17.1%
Boscan	1946	Water	10.2	35302	2754	1567	4.4%
Bachaquero	1930	Water	17.4	31285	7635	6853	21.9%
Urdaneta	1955		14.1	27288	2909	992	3.6%
Ceuta	1981	Water; Gas	27.5	14926	3016	1392	9.3%
Lama	1957	Water; Gas	31.8	10635	3669	3172	29.8%
Centro	1957	Water; Gas	34.7	8569	2353	1677	19.6%
Lamar	1957	Water; Gas	35.1	5060	1978	1543	30.5%
La Paz	1925	Water	32.5	4627	981	915	19.8%
Mara	1945		23.5	3978	727	475	11.9%
Cabimas	1917		22.0	2896	664	509	17.6%
Mene Grande	1914	Steam	19.3	2889	837	739	25.6%
Tomoporo	1981		26.4	2813	370	51	1.8%
Motatan	1952	Water	25.5	2559	486	316	12.3%
Barua	1958		21.2	1869	427	195	10.4%
La Concepcion	1925		36.0	1821	295	204	11.2%
Alturitas	1950		29.9	1467	172	105	7.2%
Sur Lago	1973		35.7	957	288	91	9.5%
Rosario	1959		36.1	422	110	66	15.7%
Cumarebo	1931		45.3	142	70	61	43.1%

Table 2 (continued)
Top 100 Traditional Oil Fields by Size (OIP)

Field	Discovery Year	IOR / EOR Injected Fluids	°API	OIP (mbo)	EUR (mbo)	Cumulative Produced Oil (mbo)	Current RF (%)
Western Basin (continued)							
Block XIII, Lago Sur	1975		35.3	123	30	2	1.2%
La Vela	1983		28.2	82	11	0	0.1%
Sur Oeste Lago	*		26.0	50	5	2	4.0%
Sub- Total, Bbo				**267**	**51**	**37**	**14.0%**
Eastern Basin							
Santa Barbara	1941/ 88	Gas; Steam	31.3	8890	1324	1595	17.9%
El Furrial	1986	Water; Gas	26.8	8358	1140	3345	40.0%
Mulata	1942	Water; Gas	28.8	5159	899	1448	28.1%
Orocual	1933	Water; Gas	17.4	4881	654	205	4.2%
Mata	1954	Water; Gas	28.1	4169	877	649	15.6%
Quiriquire	1928	Gas	16.7	3831	812	771	20.1%
Guara	1942	Water; Gas	24.2	3371	767	541	16.1%
Oritupano	1955		17.6	2614	475	454	17.4%
Santa Rosa	1941	Water; Gas	43.5	2561	751	446	17.4%
Oficina	1937	Water; Gas	26.6	2487	557	396	15.9%
Yopales	1937	Water; Gas	18.4	2435	385	185	7.6%
Jusepin	1938	Gas	31.3	2087	314	344	16.5%
Nipa	1945	Gas	22.7	2044	503	286	14.0%
Pirital	1945	Gas	30.7	1952	446	238	12.2%
San Joaquin	1939	Gas	21.5	1895	467	161	8.5%
Dacion	1945	Water; Gas	19.8	1801	552	474	26.3%
Chimire R	1948	Miscible Gas	33.2	1774	562	399	22.5%
Oveja	1954	Gas	25.5	1758	272	280	15.9%
Pedernales	1933	Gas	19.6	1447	209	110	7.6%
Zapatos	1955	Gas	33.0	1445	301	258	17.8%
Aguasay	1955	Gas	34.3	1408	301	130	9.2%
El Roble	1939		43.6	1330	261	43	3.2%
Nardo	1954	Water; Gas	23.8	1285	263	133	10.3%
Temblador	1936	Steam	15.6	1261	298	146	11.6%
Limon	1954	Water; Gas	21.8	1253	240	136	10.8%
Santa Ana	1937	Water; Gas	39.2	1216	282	143	11.7%
El Carito	1988	Water, Gas	28.2	1170	187	423	36.1%
Corocoro	1999		24.4	1088	210	85	7.8%
Ostra	1943	Gas	15.6	1083	155	104	9.6%
Oscurote	1952	Water; Gas	23.0	901	169	116	12.9%

Table 2 (continued)
Top 100 Traditional Oil Fields by Size (OIP)

Field	Discovery Year	IOR / EOR Injected Fluids	°API	OIP (mbo)	EUR (mbo)	Cumulative Produced Oil (mbo)	Current RF (%)
Eastern Basin (continued)							
Adas	1954		12.7	892	97	19	2.2%
Budare	1954	Gas	29.9	891	270	169	19.0%
Elotes	1954	Gas	34.3	841	190	135	16.1%
Zumo	1954	Gas	22.8	788	135	149	18.9%
Uracoa	1937		16.0	779	193	124	15.9%
Guico	1944	Gas	28.1	669	139	64	9.6%
Lido	1954	Gas	23.6	628	140	76	12.0%
Merey	1937		14.4	609	75	41	8.7%
Leona	1938		24.8	569	146	83	14.6%
Zorro	1963	Water; Gas	27.8	538	127	104	19.3%
Boqueron	*	Miscible Gas	30.3	486	101	73	15.0%
Acema	1966		25.8	482	114	46	9.6%
Socororo	1940	Gas	18.4	458	63	15	3.3%
Onado	1971		25.6	455	81	33	7.3%
Ganso	1948		17.9	447	88	55	12.3%
Las Mercedes	1941		32.1	437	121	93	21.2%
Nigua	1953	Gas	26.4	408	90	74	18.1%
Tacata	1952		38.7	385	119	29	7.6%
Levas	1956		18.0	374	73	36	9.6%
Quiamare	1942		40.4	323	85	51	9.6%
Caracoles	152	Gas	33.9	313	74	50	16.0%
Tucupita	1945		16.1	291	111	56	19.1%
Isla	1954	Gas	39.1	279	93	73	26.2%
Finca	1956		36.2	250	60	33	13.2%
Caico Este	1946	Gas	32.2	247	69	34	13.7%
Nieblas	1954	Water; Gas	25.8	239	43	31	12.8%
Las Piedras	*		19.9	231	39	13	5.5%
Araibel	1954		33.9	210	50	28	13.3%
Freites	1949	Water; Gas	34.6	182	42	17	9.2%
Pato	1956		41.8	177	40	8	4.7%
Caico Seco	1946		32.0	158	32	12	7.9%
Kaki	1953	Gas	40.1	157	32	23	14.7%
Casma	1974		35.7	139	42	0	0.1%
Ira	1957		34.7	132	33	10	7.9%
Bella Vista	1952		26.9	109	21	14	12.7%
ADM 101	1954		20.7	93	21	4	4.4%

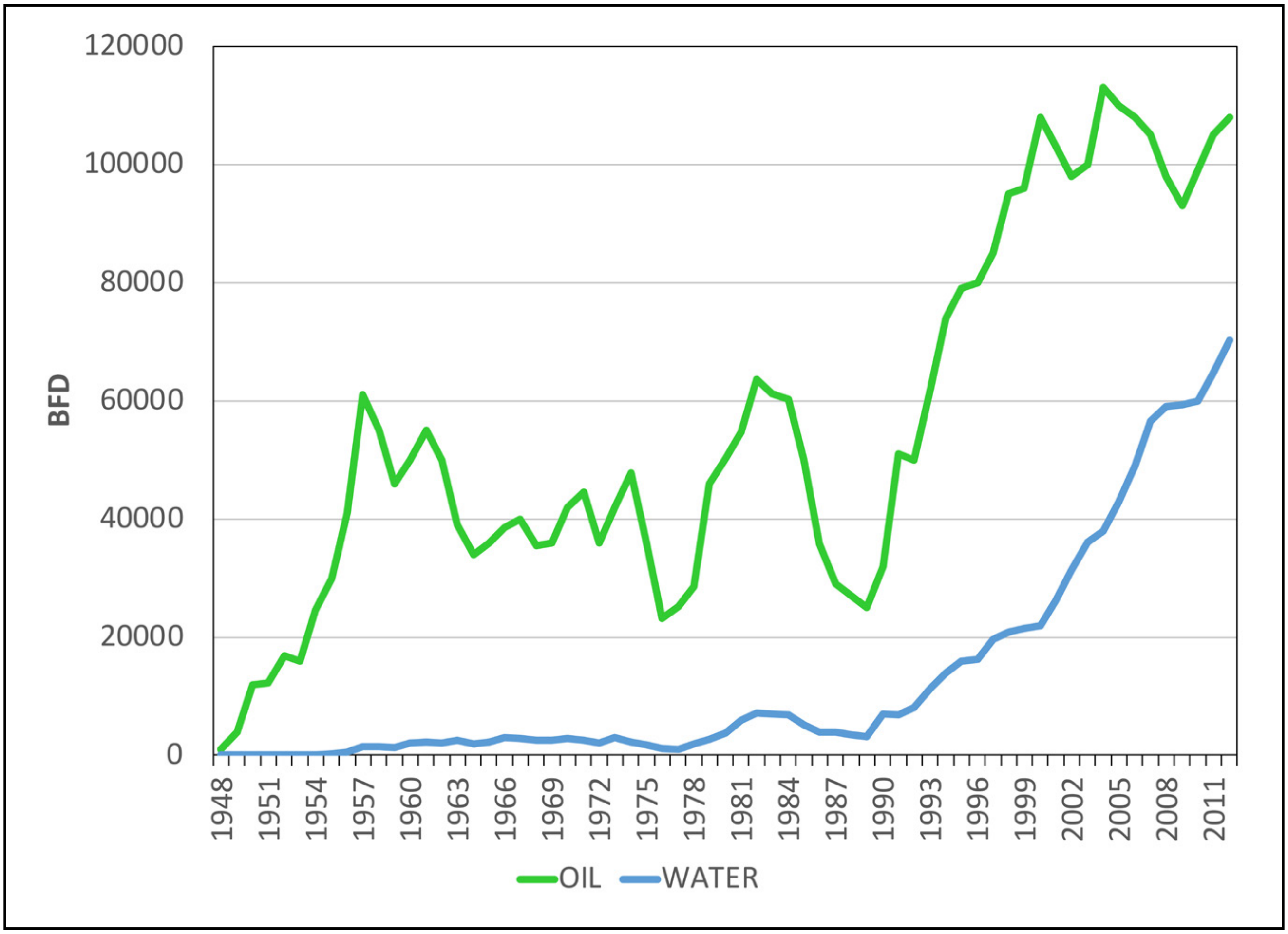
Table 2 (continued)
Top 100 Traditional Oil Fields by Size (OIP)

Field	Discovery Year	IOR / EOR Injected Fluids	°API	OIP (mbo)	EUR (mbo)	Cumulative Produced Oil (mbo)	Current RF (%)
Eastern Basin (continued)							
Bombal	1965		19.6	80	15	2	3.0%
Coporo	1954	Gas	35.8	58	23	10	17.5%
Sub-Total, Bbo				**92**	**18**	**16**	**17.3%**
Barinas-Apure Basin							
Sinco	1948		24.3	1663	673	386	23.2%
Guafita	1984		28.6	1064	590	460	43.2%
Silvestre	1948		25.8	877	328	157	17.9%
La Victoria	1984		34.6	672	384	217	32.3%
Paez Mingo	1967		17.9	530	168	85	16.1%
Borburata	1994		25.4	327	109	69	21.1%
Maporal	1958		25.8	307	104	32	10.3%
Palmita	1957		25.8	167	37	3	1.6%
Hato Viejo	1965		26.4	47	18	8	16.1%
Sub-Total, Bbo				**5.6**	**2.4**	**1.4**	**25.0%**
TOTAL				**365**	**71**	**54**	**14.9%**

Source: PODE, Publications.
*Official values not available

Boscan is an extra-heavy oil field that was discovered in 1946 by Richmond Oil (which evolved to Chevron) and was operated by Chevron through 1975 when the oil industry was nationalized, and its operation was transferred to PdVSA. As shown in **Fig. 6**, production reached a high of 60,000 b/d in 1956 followed by a steady decline through 1964 to 40,000 b/d and staying stable through 1975 as nationalization approached. At nationalization, the rate had dropped to 20,000 b/d; afterwards, production fluctuated in the 40,000-60,000 b/d range. Average well rates were in the 200-300 b/d range.

Figure 6
Production History of the Boscan Field



Source: Publications, Proprietary Reports

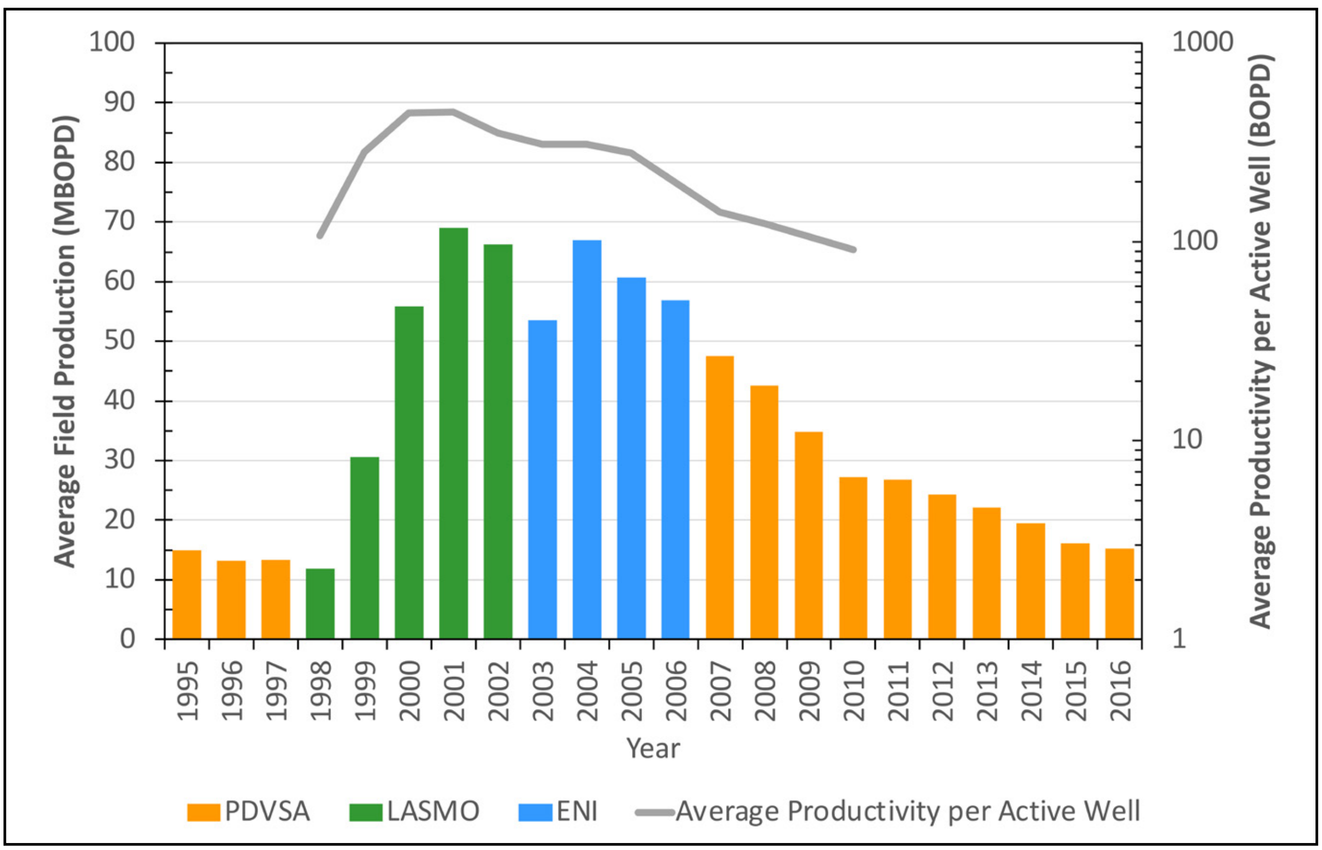
With PdVSA as its operator, an aggressive well-rehabilitation campaign was implemented in the 1994-1996 period and production increased to a then all-time high of 80,000 b/d in 1996; average per well production was around 320 b/d. Chevron returned as operator of the field in 1997 leading a JV with PdVSA, with an ambitious investment plan in drilling, major well-repair work and well-rehabilitations. Production increased gradually reaching 115,000 b/d in 1999 and held through 2002 when it dropped for market and local conditions. In 2003, drilling high-slant wells with new technology in conjunction with an expanded well-workover program was re-initiated to compensate for the production decline caused by the pressure drop, but more so by the increasing water-cut (30-40%). The existing water disposal system was also converted to a dual-purpose water injection project. All of this together arrested the pressure-decline.

It is interesting to note that under the JV program initiated in 1997, major investments in new drilling technology, workovers, and the implementation of a water injection project in an extra- heavy oil reservoir have played an important part in appreciably expanding the production of this old giant oil field. The corollary is that when the market, price, operational conditions, technological elements, and contractual conditions are such that the required major investments can be recovered as planned by the operator and the government, the rehab project can be successful.

Dacion is a medium-heavy giant oil field that was discovered around 1940 by Gulf Oil in the Eastern basin. The reservoirs in this field are either poorly consolidated or unconsolidated sands, high porosities averaging 26%, with an average thickness around 20 net feet per producing horizon. Most reservoirs have a strong natural water drive. Production peaked around 44,000 b/d in the 1950s with water cuts as high as 30 % in a short time. As the water cut increased, the rate declined to 20,000 b/d in the 1960s. The operator, Gulf Oil, did not make significant investments since its concession was nearing expiration and there was increasing talk about 'nationalization'. After nationalization (1976) and under PdVSA's operational control, production continued to decline dropping to 13.000 b/d in 1997; production per active well was a low 117 b/d and field water cut had increased to 70%. Close to 55% of all wells were shut-in. During the bidding for mature fields, Dacion was awarded to the independent LASMO. LASMO's plan was to conduct an aggressive work program including drilling close to 100 wells and a major expansion of surface facilities to handle very large volumes of fluids.

Fig. 7 shows the production history for the last three years of the PdVSA operation ending in 1997, with a declining production down to some 13.000 b/d. Production dropped for the first year of the LASMO operation as drilling and facilities expansion started but then increased significantly reaching a peak of some 69,000 b/d by 2002. LASMO was acquired by ENI the following year as production had dropped off to 53,000 b/d. ENI followed the same production strategy but with a much stronger financial muscle to handle the required cash calls of the operating agreement. The production rate with ENI as the operator picked up again to 67.000 b/d by 2004. The number of active wells at the time (215) indicates a rather well-attended operation, including some daily production peaks of 70,000 b/d. As expected, the average water cut remained rising.

Figure 7
Production History of the Dacion Field



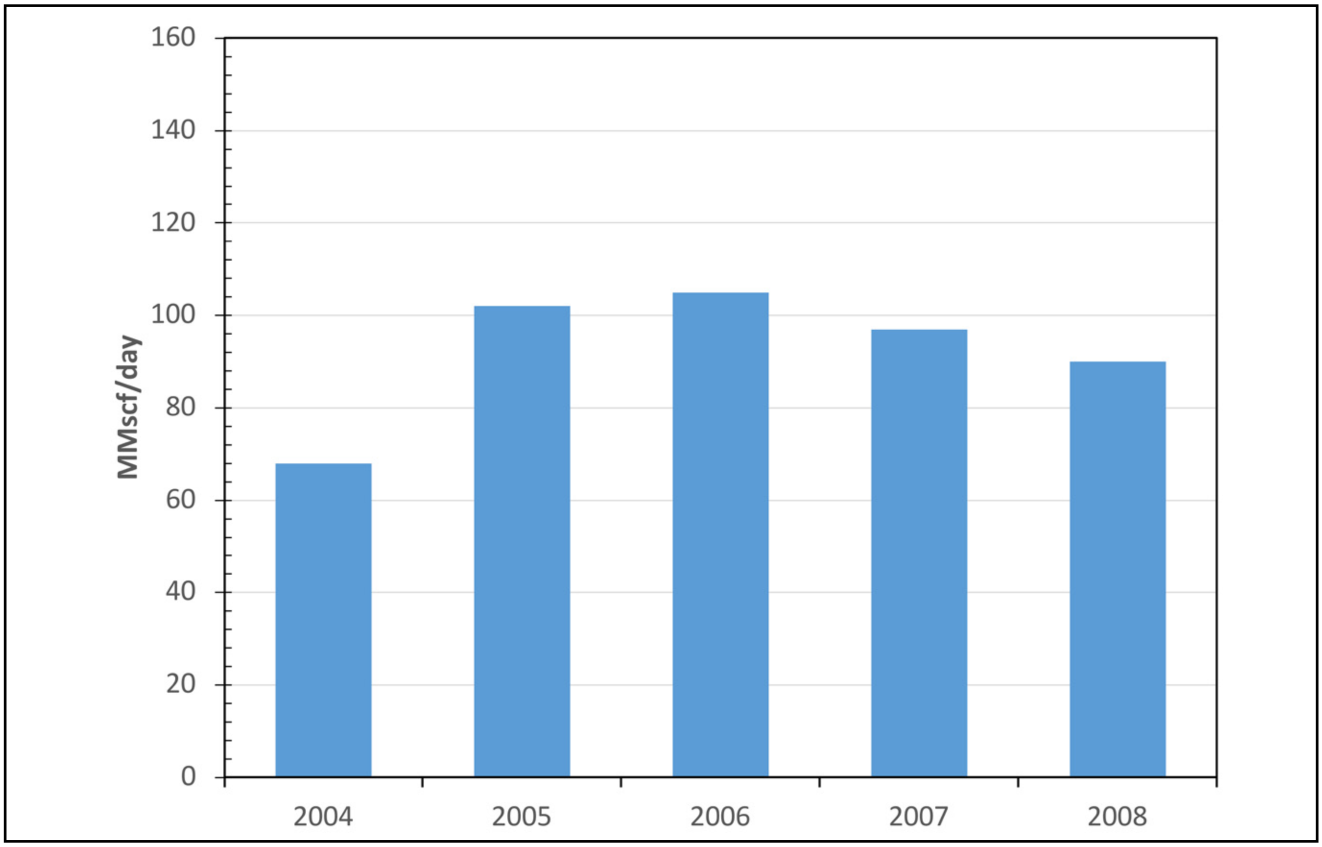
Source: Publications, Proprietary Reports

In 2005, the drilling pace was decreased to 50% of the previous year and production dropped accordingly to 57,000 b/d in 2006. The drop in the drilling investment was the result of conversations with PdVSA, who was about to change the conditions of the ENI Agreement (as well as of other operators). ENI did not accept the new contract conditions and returned the field to PdVSA. This marks the end of the ENI period in Dacion and the beginning of a second period of PdVSA as its operator. **Fig. 7** shows the steady decline of the production from 48,000 to 15,000 b/d through 2016. Production was barely 5,000 b/d in 2019. Evidently the lack of new investments has led to this point. When ENI bought LASMO and became the Dacion operator, in addition to the new-well drilling, it also increased the field fluid handling capacity to 350.000 b/d. ENI held on to the LASMO strategy because the production program was contingent on the policy of ever-increasing production of total fluids handling, as part of the mitigation of the oil rate decline caused by the increasing water-cut. When the invested capital recovery period is altered by any set of conditions, new investment will definitely either drop or stop all together for a given asset. This happened at the end of the ENI cycle in Dacion.

Yucal-Placer is a giant gas field that was included in this discussion because it presents a unique combination of very difficult operating conditions. It was discovered in 1948 by an international company, Petrolera Las Mercedes. Its unusually tight reservoirs at depths of around 7,000 ft contained gas with a high CO2 content in the range of 5-30% which required expensive processing with specialty-steels production tubulars. Additionally, the controlled price for gas in the local market did not contribute to the promotion of any production plan. Production before 2004 was insignificant, with a cumulative of only 140 bcf over its history.

In 2003 YPERGAS, led by Total, was granted a gas license to exploit this stranded field. Several local engineering companies were the other minority partners. **Fig. 8** shows its production history which reached in 2008 gross rates averaging 115 MMscf/d to meet the 100 MMscf/d target of clean gas (after CO2 removal). This gross production rate from 2003 onwards was obtained from only five new wells peaking at 120 MMscf/d by mid-2006. These wells were completed with special steel tubulars and had been successfully fractured. The surface facilities were also specially built to handle the very corrosive gas by processing it in a CO2 removal plant.

Figure 8
Production History of the Yucal-Placer Field



Source: Publications, Proprietary Reports

Although detailed plans were drawn in 2009-2010 to raise the production target to 300 MMscf/d of treated gas, the investment plan was essentially suspended because the government did not approve to adjust the local gas price required so the project´s income would meet the investment capital recovery in a reasonable time and also yield typical returns on new investment for this type of high technology production plans.

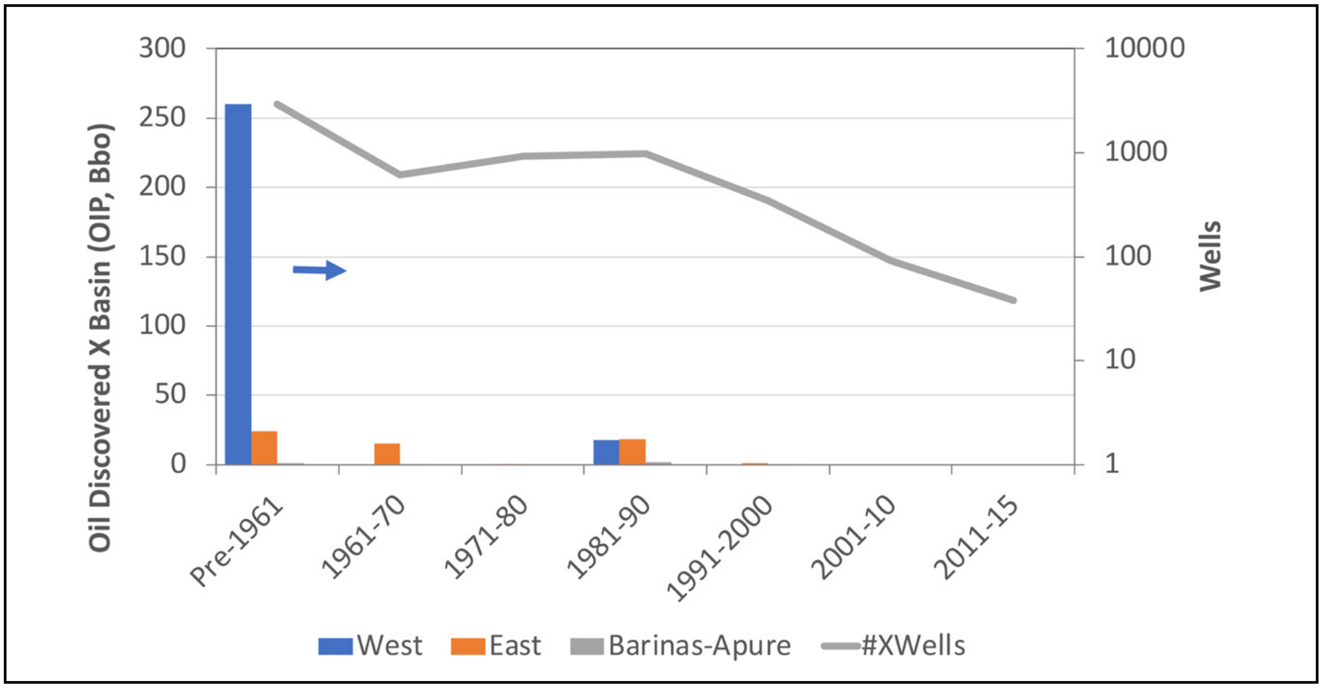
It should be noticed that YPERGAS was so technologically advanced in its planning that it completed the only corrosive gas commingled production Field Pilot Test in Venezuela from different stacked reservoirs in single wells, fully instrumented to split the measured commingled production into single reservoir volumes. This was necessary in order not to alter or corrupt the record for individual stacked reservoirs, as required by law, and keep the integrity of the official reserves books per reservoir in all fields.

Once again, a critical project to allow for the production of a giant field with extremely difficult operating features, a first in the country, did not move forward because adequate investment conditions were not provided. The foreign operator Total demonstrated, by performance, that technological strength can overcome the most difficult operating conditions, if the financial architecture of the contract allows for a fair and reasonable setting.

In summary, there is considerable potential left in Venezuela's numerous advanced mature oil fields, maybe as much as 18 Bbo of fresh reserves. As we have seen in the three field examples that were briefly analyzed, mature fields are complex and require creativity to devise the appropriate revitalization programs suitable for each one. Equally, they involve substantial investments which require reasonable conditions for capital recovery and fair-market capital yields. The contract or agreement has to provide all of the above for success.

Venezuela's exploration history reveals an interesting story of its oil industry with a significant milestone in the year 1960. Before this year, about 285 Bbo of traditional oil (OIP) had been discovered following the drilling of 3,000 (2,956) wildcat wells. As of 1960, serious rumblings of nationalization began and continued increasingly over the next 15 years. The industry finally was nationalized in 1976 and ever since has been under the aegis of PdVSA. Coincidentally, post 1960 another 2,990 wildcats have been drilled and an additional 165 Bbo of oil have been discovered. **Fig. 9** offers a quick look of exploration activity to the present day for the three main basins, in 10-year intervals.

Figure 9
Exploratory Wells Drilled and Oil Discoveries by Basin through 2015 (10-year intervals)



Source: PODE, USGS, Publications

After WWII, Venezuela embarked on a massive exploration effort with a goal to quickly increase production. Wildcat drilling increased to 400 wells per year at the end of the 1950s. Thereafter, post 1960, the pace of drilling dropped steadily to 200 wells per year, to 100 and finally to 50 in 1970. With the large volumes of fresh reserves discovered pre-196, including 24 Bbo in the Eastern basin, production increased from 1.5 million b/d in 1950 to 3 million b/d at the end of the decade. Production peaked at 3.7 mb/d in 1970 and thereafter began to decline. The relationship between exploration and production is obvious.

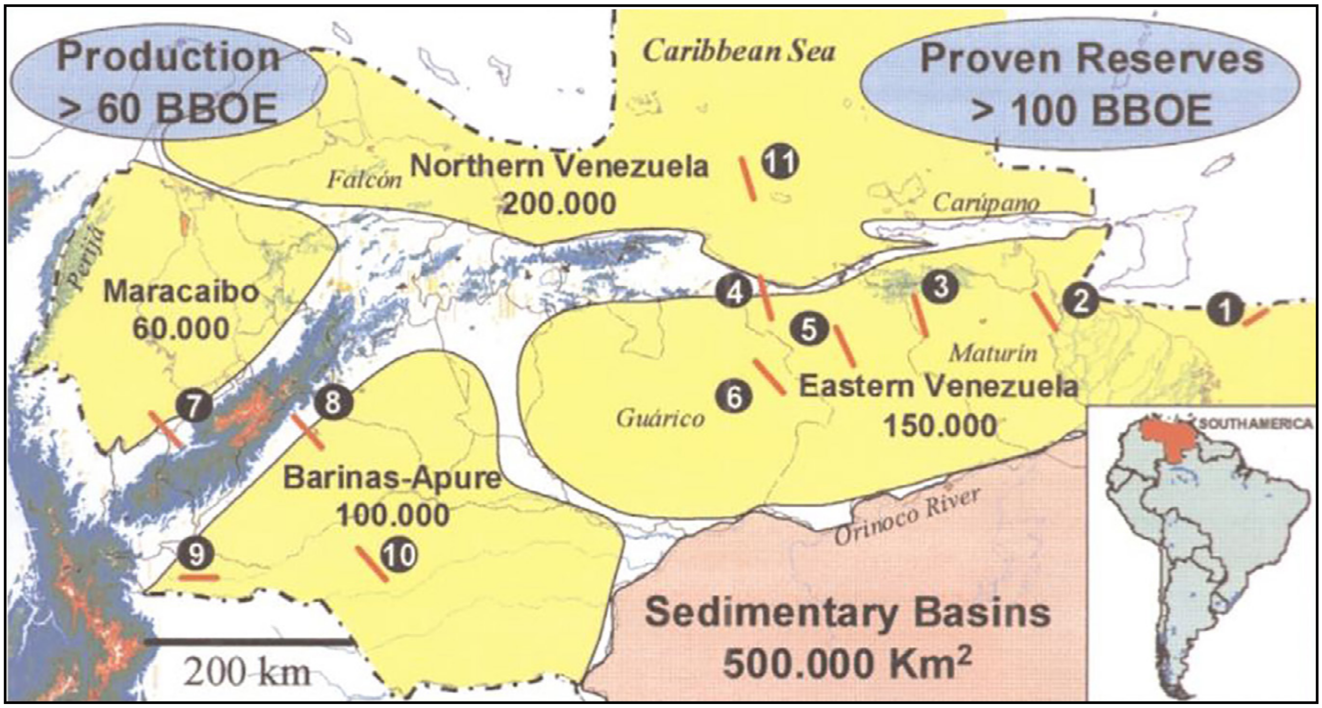
As shown in **Fig. 9**, there was a bump in wildcat drilling to 103 wells per year in the latter half of the 1970s – post nationalization – and to 154 in the first half of the 1980s. This secured the discovery of three giant fields with 18 Bbo OIP in the El Furrial Trend and another 18 Bbo OIP (Ceuta-Tomoporo) in the Western basin. Thereafter, the exploration endeavor diminished continuously to 40 wells per year in the second half of the 1980s, to 35 in the 1990s and to 9 in the 2000s. Apparently, this reduced exploration effort was a consequence of a decision to concentrate on the development of the Faja. Still, a total of 476 wildcats were drilled from the 1990s through 2015 and only 1.4 Bbo of OIP were discovered. This is somewhat disconcerting. Furthermore, during that 25-year period the country produced a huge 14 Bbo of traditional oil! This high ratio of production to discoveries is conducive to a precipitous depletion of the country's remaining reserves which now stand at just about 10 Bbo.

Regarding offshore, Venezuela has been exploring it since the 1950s. A total of about 50 exploration wells have been drilled and Corocoro is the only commercial oil discovery. On the other hand, six giant gas fields have been discovered of which Perla, the largest of the group, has been producing since 2015; ENI is the operator. It is located in the Gulf of Venezuela where eight wildcats have been drilled to date. The next largest giant is Loran located in the Atlantic Ocean which started production in 2013. The other four giant gas fields are located in the Caribbean Sea (see **Fig. 1**) and are still in appraisal. Twenty-one wildcats have been drilled in the Gulf of Paria and all came up empty. The Loran field is interesting for a couple of reasons. It is a cross-border field that was discovered by PdVSA in 1983 with 10 tcf of gas-in-place. Venezuela holds 73% and Trinidad the remaining 27%. Production began in 2013 following a landmark Unitization Agreement between the two countries. The field, now called Loran-Manatee, was producing 750 MMscf/d prior to being affected by sanctions-related issues. The Unitization Agreement has served as a model for two other cross-border gas fields: Manakin-Coquina (740 bcf) and Kapok-Dorado (310 bcf).

Reserves are the basis of production and as such discovering new reserves must be one of the country's main goals. First, finding new reserves is an endeavor of high geologic uncertainty. Following a discovery, the process of developing the new field is characteristically slow. Typically, it requires 4-5 years to complete the cycle from drilling a successful wildcat to reaching the field's full production potential. Add another 2-3 years of comprehensive data valuation prior to selecting the location of the successful wildcat. The process is also very technological and capital intensive, requiring a capex of roughly $10-15 USD per barrel of reserves discovered. This is equivalent to an investment of about $2-3 billion USD for finding and developing a new 200 million barrel field which would generate a production capacity of 95,000 b/d. And finally, the process requires exceptional exploration prowess to minimize the huge exploration risk. The success ratio of wildcats is just one in ten.

Regarding Venezuela's future exploration potential, the literature is rich with the geology of its numerous and huge giant oil fields. An excellent treatise on the subject was recently presented by Audemard and Serrano (Ref. 16). They describe in detail eleven plays, **Fig. 10**, they consider identify the country's large potential of undiscovered oil resources estimated at 40 Bbo. In a private document the renowned international explorationist, Mark Shann, who is hands-on familiar with Venezuela's geology, suggests two areas that warrant future exploration attention, and both are in the northwest of the country: the new Gulf of Venezuela and the venerable Maracaibo Basin. The ongoing discussion represents a continuation of Shann's comments.

Figure 10
Venezuela's Proven Reserves of Traditional Oil and Gas



The areas shown are the major onshore and offshore basins; numbers correspond to the areal extent of the basins in Km2. Cumulative production and proven reserves are indicated in equivalent barrels. Seismic lines used to illustrate Future Petroliferous Provinces are in red and refer to the numbers of the eleven major plays discussed in Audemard and Serrano's paper, Ref. 16.

The 2009 Perla wet gas condensate discovery, located in the relatively under-explored shallow water Gulf of Venezuela, to the north of Lake Maracaibo, is the largest gas field found in Latin America. The Perla play is unique in that it relates to Miocene gas-prone source rocks and the Perla-1X wildcat is the first to have penetrated the Oligo-Miocene carbonate play fairway. This points to the basin being in the early stage of exploration maturity when medium to large discoveries may still be expected.

By contrast to the underexplored Gulf of Venezuela, the Maracaibo Basin is one of the world's true super basins, with more than 30 Bbo produced since Zumaque-1. Despite its long exploration history this basin has had a complex geological story and is still likely to have undiscovered pools related to understanding of the multiphase oil and gas charge across many stacked reservoirs and in relation to its strike slip nature of many of the trap styles present. In this case, complexity at the basin scale for this super giant oil province means more future potential than for a simpler basin evolution. Maracaibo also benefits from a multitude of well and seismic data availability to constrain what will be a complex basin modelling and play fairway analysis project.

The Eastern Basin is Venezuela's other major oil province and is one of the classic fold-belt to foreland basins of the world. This is a simpler basin type, and, in that sense, it is likely to have been well explored to date. The exception to this might be extending the eastwards limit of the prolific Furrial *buried frontal fold* trend towards the Orinoco. An effort to extend the drilling of deep frontal folds eastwards in the late 1990's did not reach the reservoir objective, and so deep fold structures remain untested and as such there is a gap in defining the eastern limit of the Furrial trend.

In summary, priority exploration for oil and gas should focus on shallow water offshore. Audemard and Serrano said it best: 'Venezuela has a new variety of exploration opportunities for the future'.

CLOSING COMMENTS – A FORWARD LOOK

Venezuela is known to hold the world's largest proven oil reserves and as of 2012 it was one of the world's largest exporters of oil. In 2021 it is producing barely 300,000 b/d of oil. This paper gives a quick overview of what has technically happened in its over 100 years of production history. We have reviewed the hydrocarbons we have found, what we have produced, what remains in the ground – over 95% of the Faja's 1.3 trillion barrels of oil and likewise 85% of the 450 billion barrels of traditional oil discovered so far in over 320 oil fields – and most importantly, based on field experience, what we can expect to produce over the next 20-30 years.

Most of Venezuela's oil fields are advanced mature, in the 4th quarter of their economic life. One hundred of its top fields account for 80% of the 450 billion barrels of oil discovered and have an average recovery factor of only 15%. An aggressive/successful IOR/EOR effort together with optimized lifting and fluid handling could produce an additional 5% or 18 billion barrels of fresh reserves that can support a production level of 500,000 b/d for a period exceeding 20 years.

For the Faja with its huge extra-heavy (7-13° API gravity) crude oil resources, under proper operational and financial conditions it is not unreasonable to return to produce 1.0-1.3 million b/d for a long time, 20-30 years. This is close to 3% recovery if only half of the Faja's oil-in-place (OIP) is affected by the production program.

The offshore exploration program with constrained efforts to date – only 50 wildcats drilled – has discovered six giant gas fields with 42 tcf of gas and one world class oil field (Corocoro). A concerted exploration plan should double the already discovered gas production potential, probably to no less than 6 bcf/d. A sustained rate of 100 MMscf/d for 30 years consumes 1.1 tcf of reserves. Offshore oil is more complex given the results to date. Overall, explorationists believe there are many new opportunities that point to a resource potential great than 40 Bboe yet to be discovered.

Venezuela would likely need to revitalize its oil industry before it could cultivate and develop other important industries to consolidate its economy long term. This would take enormous investments – estimates have been given throughout this study – and the involvement of operating companies with access to the newest technologies required for the modern cost-effective development of resources.

How can we move forward into the future? All ventures begin by a constructive dialogue among the different actors in this case the Government holding the resources and the major financing groups. A bilateral team working on a modern version of an investment model for financing the three variants for production increase: Faja, mature fields and exploration. Since the hydrocarbon resources are below ground and have different degrees of difficulty when it comes to finding their possible location and accessing them (field depths, onshore and offshore, nature of the fluids to be produced, and several other important issues), geographical packaging and package ranking with available indicators is very convenient both for the country and for the investor-operators. The latter translates directly to the different levels of investment required for the future production of the known fields and for finding and producing newer fields discovered by the future exploration activities.

Likewise, the group should put together the basic elements of a contractual relationship, mutually satisfactory, that will work over-time for the project duration, and which can be altered by mutual agreement, should that be required. This bilateral development of such mutually agreed conditions arises from two proven conditions tried in the successful operation of many international-cross-border projects: the capital recovery times and profitability yields of the invested funds must be considered 'stable' in that they should not be subject to major changes by either participant brought about unilaterally. They should include an agile mechanism to adjust the course when needed, adjustment which will benefit all the participants. All it takes is to begin a productive dialogue among the participants in this proactive desirable course. Hopefully.

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