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A JOINT LAW VENTURE

Navigating the Regulatory Landscape of the Oil and Gas Industry Across Latin America and the United States

INTRODUCTION

In response to the dynamic developments shaping the oil and gas sector across Latin America and the United States, Duane Morris has collaborated with esteemed law firms in Argentina, Brazil, Colombia, Mexico, Ecuador, Peru, and Venezuela to produce an updated, forward-looking overview of oil and gas regulatory compliance in our respective countries.

As global energy demands shift and regulatory frameworks evolve, navigating the complexities of the oil and gas industry becomes increasingly challenging. This publication aims to provide clear insights on licensing, environmental compliance, safety standards, taxation, and investment incentives, helping businesses operate effectively in a highly regulated environment.

This guide offers a summary of current policies, permitting requirements, fiscal regimes, import/export regulations, and sustainability measures across key Latin American markets. By examining each country's framework and leveraging local experience and insight, this publication empowers businesses to make informed decisions, mitigate risks, and identify opportunities in the region's changing oil and gas landscape.

At Duane Morris, we are committed to supporting our clients in advancing their strategic objectives while successfully navigating the complexities of oil and gas regulations.

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Argentina has increased its proven hydrocarbon reserves mainly by developing unconventional resources in the Vaca Muerta formation. The Federal Secretariat of Energy reported that as of December 31, 2023, Argentina had proven crude oil reserves of 477,270 million cubic meters (MMm^3), equivalent to 3 billion barrels of oil (BBO), and crude oil resources of 774,366 MMm^3, equivalent to 4.87 BBO. In the same year, proven natural gas reserves stood at 487,472 MMm^3, or 17.2 trillion cubic feet (TCF), while natural gas resources reached 909,158 MMm^3, or 32.12 TCF. Both international and national oil companies, led by YPF, the state-controlled energy leader, are key players in Argentina's hydrocarbon industry. In this way, private operators have driven production growth, particularly in unconventional resources.

Argentina's hydrocarbon resources include conventional, offshore and unconventional reserves, each with distinct geological characteristics and extraction methods. Unconventional resources, such as Vaca Muerta—one of the world's largest and most promising shale formations—are a priority due to their high productivity potential. Offshore exploration, which requires significant investment but offers long-term growth opportunities, is increasingly relevant and a promising focus, especially in the Cuenca Argentina Norte, Cuenca Malvinas Oeste and the Cuenca Austral offshore basins. Conventional fields, which are still productive but mature and declining, are the industry's last option.

Hydrocarbon Jurisdiction in Argentina

Argentina operates under a federal system in which the national authority and provincial governments share government powers and responsibilities, including the ownership and management of hydrocarbon resources. Since the 1994 constitutional reform, provinces own the oil and gas (O&G) resources in their territories, except for offshore deposits beyond 12 nautical miles, which fall under national jurisdiction. However, the national government regulates the legal framework governing hydrocarbon extraction to ensure legislative uniformity.

Law No. 26,197 of 2007 confirmed the provinces as the regulatory authorities for the Federal Hydrocarbons Law No. 17,319 (the FHL) within their jurisdictions. More recently, Law No. 27,742, known as the "Bases and Starting Points for the Freedom of Argentines" law, (the Bases Law), along with its Implementing Decree No. 1057/2024 (Decree 1057), has reformed both the FHL and the Natural Gas Law No. 24,076. These reforms aim to liberalize and deregulate the energy sector, encourage greater private and mixed enterprise participation, and reduce the role of state-owned companies in regulated hydrocarbon activities, while positioning Argentina into a hydrocarbon-exporting country. The new legislation treats state-owned enterprises and private operators equally in terms of requirements, obligation and regulatory oversight. Consequently, state-owned companies must comply with the same inspections and administrative requirements as private concessionaires and permit holders. Additionally, the Bases Law removed all restrictions on foreign legal entities freely participating in hydrocarbon activities in Argentina.

Hydrocarbon Licensing in Argentina

The FHL establishes a regulatory framework that grants operators exclusive rights to explore, develop and extract hydrocarbons through exploration permits and production concessions, which are awarded through competitive tenders by the federal or provincial governments, depending on resource location. An exploration permit grants operators the exclusive right to conduct all activities necessary for hydrocarbon prospecting in a defined area for an initial term of up to six years for conventional resources (divided into two three-year periods) and up to eight years for unconventional resources (divided into two four-year periods). An extension of up to five years may be granted in both cases. Offshore exploration permits for conventional resources may be extended by one additional year per phase. If hydrocarbons are discovered, the exploration permit holder may request a production concession, which grants exclusive extraction rights for a term of 25 years for conventional resources, 35 years for unconventional resources and 30 years for offshore operations. National or provincial authorities may extend these terms by up to 10 years under justified criteria. The Bases Law also established that permit holders and concessionaires own the hydrocarbons they extract and, therefore, are free to transport, market, industrialize and sell their derivatives. However, concessions awarded before the Bases Law's enactment remain subject to prior legal terms, meaning that these holders may request successive 10-year extensions for their concessions rather than a single, justified 10-year extension. Additionally, the Bases Law allows concessionaires to request the subdivision and conversion of a conventional concession into an unconventional concession until December 31, 2028, provided they submit a pilot plan demonstrating commercial viability of such conversion. If approved, the new unconventional concession will have a 35-year term from the request date, while areas not included in the new unconventional concession will remain under the original conditions and terms.

Production concession holders have the right to obtain a transportation authorization for their hydrocarbons, which will align with the duration of the concession, unless they construct a permanent transportation infrastructure extending beyond their concession boundaries. At the end of the term, the infrastructure reverts to state ownership. Transportation authorizations grant the right to transport oil, gas and derivatives through various infrastructure types, including pipelines, storage facilities and ports. Unlike production concessions, transportation authorizations are not subject to a public tender, fixed terms or exclusivity. Additionally, the law establishes open access rules, requiring transporters to make unused capacity available to third parties under equal conditions and pricing. While provincial governments grant transportation authorizations, the national government retains control over authorizations that extend across multiple provinces or relate to pipelines intended for export.

Fiscal Regime and Government Takes: Taxes, Royalties and Pricing Regulations

Historically, exploration permits and production concessions were subject to a fixed royalty rate of approximately 12% calculated on production, with royalty payments deductible for income tax purposes. Under the new regulatory framework introduced by the Bases Law and Decree 1057, a more flexible approach applies, where royalty rates will be determined in each bidding process, allowing bidders to propose rates above or below a reference rate of 15%. This law also reaffirmed that royalties are the only mechanism through which provinces may generate revenue from hydrocarbon production, prohibiting them from imposing additional taxes or charges, or increasing existing ones during the term of permits and concessions, except for service fees, special contributions or general tax increases. Furthermore, the federal or provincial governments may reduce royalty rates to as low as 5%. Operators are also required to pay an annual production tax (canon) adjusted in accordance with the ICE Brent benchmark.

Environmental Regulations

Argentina’s upstream O&G sector is subject to a rigorous environmental regulatory framework at the national, provincial and municipal levels. Operators must comply with environmental quality standards and damage prevention to ecosystems, water resources, agricultural activities and other sensitive sectors. These regulations require the obtention of specific permits, impose penalties and liabilities for noncompliance and establish obligations for remediation of environmental damage. For example, in the O&G sector, operators are required to submit an environmental impact assessment during the exploration phase and upon discovering hydrocarbons. Additionally, the Bases Law and Decree 1057 have introduced the development of a harmonized environmental framework as a new objective, which aims for the implementation of international best practices for environmental management in hydrocarbon exploration, production and transportation, ensuring industry development with appropriate environmental safeguards.

BRAZIL'S UPSTREAM OIL & GAS INDUSTRY

Hydrocarbons Reserves and Industry Players in Brazil

According to the International Energy Agency (IEA), large offshore oil and natural gas discoveries have confirmed Brazil's status as one of the world's foremost oil and gas provinces. As a result, total oil supply is expected to grow by 1.2 million barrels per day, reaching 4.2 million barrels per day in 2026. IEA forecasts also expect that Brazil will be responsible for the production of about 50% of the world's offshore oil in 2040, totaling about 5.2 million barrels per day.

According to the 2024 Statistical Yearbook of the Oil, Natural Gas and Biofuels Agency (ANP), Brazil ranked ninth in the world ranking of annual volume of oil produced in 2023, totaling 3.5 million barrels per day (3.6% of the world's total). It also occupies the 15th position in the world ranking of proven oil reserves, with a volume of 15.9 billion barrels, and ranks 29th in proven natural gas reserves, with 517.1 billion m^3.

Brazil's proven oil reserves reached 16.84 billion barrels at the end of 2024, representing an increase of 5.92% on the previous year, according to the ANP. Proven natural gas reserves reached 546 billion m^3—an annual increase of 5.17%—also the highest in at least 10 years.

Hydrocarbon Exploration Regulatory Framework in Brazil

The Federal Constitution of 1988 (CRFB/88), with its Amendment No. 9 of 1995, ended Petrobras' monopoly over exploration and production activities for oil and natural gas (E&P) on Brazilian soil, which existed since the Federal Constitution of 1934 and allowed the federal government to contract or authorize private companies to operate in the sector. Right after such amendment, the government took its first steps for market opening and enacted Federal Law No. 9,478/1997 (Petroleum Law), which created the ANP as the competent regulatory agency responsible for managing, supervising and controlling the domestic industry of E&P. The ANP is also responsible for issuing resolutions and ordinances regulating all activities applicable to the entire hydrocarbon supply chain. Therefore, the ANP's regulations are legally binding, and its violation may lead to the application of penalties as set forth in Law No. 9,847/1999, as well as under the criteria of the respective E&P agreements (as defined below).

The Petroleum Law also created the National Energy Policy Council (CNPE) to act as an advisory body to the presidency, linked to the Ministry of Mines and Energy (MME), whose purpose, in turn, is mainly to assist in the elaboration of governmental energy policy guidelines. In addition to determining the guidelines and policy objectives that shall guide the sectoral regulation created by the ANP, the CNPE is responsible for authorizing and setting general guidelines for all bidding rounds to be conducted by the ANP.

The Petroleum Law created the first E&P regime in Brazil (concession regime), whereby private companies (concessionaire) participate in bidding procedures to obtain E&P rights by signing a regulated agreement with the ANP (concession agreement). Following the discovery of the pre-salt area, the government enacted Federal Law No. 12,351/2010 (Production Sharing Law), introducing an alternative regime for operations in fields located in the pre-salt area, also by means of agreements between private companies (contractors) and the ANP (production sharing agreement) and, along with the concession agreement (E&P agreements). The Production Sharing Law created the state-owned company Pré-Sal Petróleo S.A. (PPSA), which shall be a mandatory part of the production sharing agreement for the purposes of administration, management and oversight of the E&P activities performed in the pre-salt area.

A third regime, called "transfer of rights" (*cessão onerosa*), was initially created exclusively for Petrobras, and in very specific circumstances, as Federal Law 12,276/2010 granted Petrobras the right to extract up to 5 billion barrels of oil equivalent (BOE) from ungranted areas located in the pre-salt area. Once production started, Petrobras discovered that the production forecast greatly exceeded 5 billion BOE, which lead ANP to organize two bidding rounds offering exploratory rights to private agents for the surplus volumes of the transfer of rights.

It is noteworthy that under the CRFB/88, oil and gas reserves in Brazilian territory are the property of the federal government. This includes inland deposits and those in the territorial sea, the continental shelf and the exclusive economic zone. Despite the granting of rights under E&P agreements, the government remains the owner of all oil and gas reserves in Brazil. However, the CRFB/88 recognizes that ownership may be transferred upon production of oil and gas through a concession agreement, as further addressed below.

E&P Regimes in Brazil

As explained above, two regimes coexist in Brazil for the granting of E&P rights:

- **Concession Regime**: The concession regime is characterized by the fact that the risk of investing and finding—or not—oil or natural gas falls is entirely on the concessionaire, which owns all the oil and gas discovered and produced in the area granted by the government. Therefore, under the Petroleum Law, ownership of oil and gas is transferred to the concessionaire at the production measurement point, a physical mark proposed by the Concessionaire and agreed with the ANP. The concessionaire is free to dispose of its ownership rights as it sees fit.

- **Production Sharing Regime**: Under the production sharing regime, the contractor also has the right to perform, at its own risk, E&P activities in the pre-salt area. However, the federal government retains ownership of the oil and gas produced, even after the measurement point. Although ownership is not transferred, the contractor has the right to earn a return of certain approved costs incurred by exploration activities (cost oil) where they discover commercially viable reserves, as well as on production value. The federal government shall also share and pay the contractor a percentage of the production (profit oil), following minimum percentages to be reserved to the federal government established in the applicable production sharing agreement. This percentage varies according to international oil prices and well productivity.

ANP Licensing Rounds

The concession regime bidding rounds began in 1998 with the “zero round,” which ratified Petrobras’s rights over areas where it had already invested. In 1999, the ANP held the first open bidding round, allowing private companies, either individually or through consortia, to acquire exploration rights for the offered fields. To date, 17 bidding rounds for exploratory blocks and four for mature fields have been held under the concession regime, as well as six bidding rounds under the production sharing regime.

Since December 2021, the CNPE has prioritized a different model of bidding process, namely the “open acreage” model, implemented by CNPE Resolution No. 17/2017 and applicable for the concession and production sharing regimes. The open acreage is a continuous process of cycles in which the ANP offers exploration blocks and areas in onshore and offshore basins, including fields that have been returned or are in the process of being returned, without the need to wait for a block to be formally included in a bidding round (as the original bidding system explained in the paragraph above). Pre-salt and other strategic areas require specific CNPE approval. The E&P agreements and tender protocols are updated over time to reflect changes in available blocks or to improve rules and contract models.

To participate, companies must comply with the requirements of the updated tender protocol and submit their application, which is assessed and subject to approval by the Special Bidding Commission (CEL). Once approved by the CEL, bidders may submit expressions of interest for any blocks or areas by providing a bid guarantee and other documents required for public notice. An open acreage cycle begins when a declaration of interest, along with a bid guarantee, is approved. The CEL then sets a specific schedule for that cycle, typically between 120 and 180 days from publication of the first approved declaration of interest in the *Official Gazette* to the date of the public bidding session.

More than 100 national and foreign companies of different sizes have already taken part in the tenders. Currently, most of Brazil's production comes from blocks auctioned in ANP bidding rounds.

Fiscal Regime and Government Takes: Taxes, Royalties and Pricing Regulations

Under the concession regime, federal, state and municipal governments are compensated through the following, to be paid in local currency:

- **Signing Bonus**: A lump sum paid by the winning bidder upon the execution of the concession agreement. The minimum amount of the signing bonus is set out in the tender protocol documents and each company/consortium bids in response to this minimum;
- **Royalties**: Compensation fee payable monthly, usually fixed at 10% of production value. Royalties may be reduced to 5% depending on the geological risks, expected production and other relevant issues;
- **Special Participation**: Extraordinary compensation payable by concessionaires in cases of high volumes of oil and gas production or high profitability fields. Calculations are based on the production earnings after royalties, exploration investments, operational costs, depreciation and taxes;
- **Occupation Fee**: Annual fee paid for the occupation or retention of areas during the exploration, development and production phases, calculated based on the size of the retained or occupied area. The occupation fee is set by the ANP in the concession agreement. Onshore concessions also require payment to the local area owners of an amount in cash ranging between 0.5% and 1% of the production value, as set out in the respective concession agreement.

Under the production sharing regime, contractors shall also pay signing bonus and royalties, which are fixed at 15% of the production value, and neither is recoverable out of the cost oil. Unlike the concession regime, the signing bonus under the production sharing agreement regime is not offered by companies in the bidding round, but is fixed by the MME for each area. No special participation or occupation fee is payable under the production sharing agreement regime.

Environmental Regulations

As for environmental matters, the Brazilian Institute for the Environment and Renewable Resources (IBAMA) manages oversight. Decree No. 8,437/2015 and Interministerial Ordinance No. 60/2015 were designed to regulate and better define the environmental licensing process at the federal level.

The main novelty introduced by Decree No. 8,437/2015 for the oil and gas industry was the granting to IBAMA of jurisdiction over production activities in unconventional onshore reserves. Until then, licensing for the exploitation of these reserves, since it took place on land and had an eminently local impact, was the responsibility of the state environmental agencies.

The abovementioned ordinance establishes how government entities—specifically Funai, Iphan, the Palmares Cultural Foundation and the Ministry of Health—will consult and intervene in the federal environmental licensing process, with the aim of not only disciplining the process, but also speeding it up. This change is particularly important for the licensing of onshore exploration and production for conventional or unconventional resources, for which IBAMA is responsible.

The intervention of official bodies will take place from the issuing of the terms of reference that guide the environmental study through to the study evaluations and compliance with the conditions of the environmental license inserted at the request of the respective entity.

COLOMBIA'S UPSTREAM OIL AND GAS INDUSTRY

Hydrocarbons Reserves and Industry Players in Colombia

According to the 2023 Resources and Reserves Report[1] issued by the Colombian National Hydrocarbons Agency (ANH), Colombia's proven crude oil reserves stood at 2,019 million barrels (MBL) as of year-end 2023, maintaining a reserves-to-production (R/P) ratio of 7.1 years. Additionally, the report highlights an 18% increase in total contingent oil resources in 2023, and a 50% increase compared to 2019.

Regarding natural gas, although the R/P ratio decreased to 6.1 years, proven reserves remained stable at 2.373 trillion cubic feet (TCF), and total reserves reached 3.692 TCF. Between September 2022 and May 2024, the average number of gas discoveries per year was 7.6, doubling the rate recorded between 2014 and 2022.

Significant control over the hydrocarbon industry in Colombia, encompassing activities such as exploration, production, transportation and refining, is exerted by major players, including the Ecopetrol Group—through its affiliates Ecopetrol (NOC), Reficar, Cenit, Hocol and Oleoducto de los Llanos Orientales—followed by Parex Resources and its subsidiary Verano Energy, and Frontera Energy, which round out the top tier of the sector. Additional participants such as SierraCol Energy, Geopark, Gran Tierra Energy, Perenco and Petrobras also maintain relevant operations. The sector further benefits from the dynamism of companies such as Petrosantander, Samaria Llanos, Carrao Energy and MKMS Enerji, which have demonstrated notable relative growth in recent years. These companies collectively shape the financial and operational landscape of Colombia's hydrocarbon sector.

Hydrocarbon Jurisdiction in Colombia

Colombia's oil and gas sector is primarily governed by the Ministry of Mines and Energy, which is responsible for establishing regulatory hydrocarbon policy in Colombia and issuing the technical regulation for these activities.

The ANH is responsible for managing hydrocarbon resources and awarding exploration and production contracts, which are regulated through administrative acts known as "*acuerdos*" and specific contract models issued by the ANH for each competitive process to allocate areas and contractual rights.

The Energy and Gas Regulatory Commission is responsible for regulating technical and economic matters related to transportation, distribution and commercialization of natural gas and liquefied petroleum gas.

Environmental and social matters fall under the authority of the Ministry of Environment and Sustainable Development and the National Environmental Licensing Authority (ANLA), which is responsible for issuing the environmental licenses and permits required for upstream activities. Furthermore, regional environmental authorities (such as *Corporaciones Autónomas Regionales*) play a complementary role by monitoring and enforcing environmental obligations within their respective jurisdictions.

The sector is governed by a comprehensive legal framework, including the Petroleum Code (Decree No. 1,056 of 1953), Decree No. 1,073 of 2015 (Unified Regulatory Decree of the Mining and Energy Administrative Sector), Law No. 142 of 1994 (Public Utilities Law) and the National Development Plans. In addition to these primary legal instruments, the competent authorities also issue technical, legal and economic regulations, such as the mentioned *acuerdos* issued by the ANH.

[1] Available in the following link and in the following link.

Hydrocarbon Licensing in Colombia

Pursuant to the Colombian Constitution, the state is the exclusive owner of subsoil nonrenewable resources and has full authority to determine the rights to be held and royalties or compensation to be paid by investors for the exploration and production of any hydrocarbon resources. Throughout history, the following contracting regimes for the exploration and exploitation of hydrocarbons have existed in Colombia:

Concession contracts granted under the Petroleum Code

Before 1974, the state granted private companies the right to explore and exploit hydrocarbon resources in certain areas of the country through concession contracts regulated by the Petroleum Code (Decree No. 1,056 of 1953). Under this regime, the concessionaire had operational and financial control over the exploitation and as compensation had to pay royalties to the state based on hydrocarbon production. According to the best available public information, currently, there are no concession contracts for the exploration and exploitation of hydrocarbons in force.

Association contracts

From 1974 (Decree No. 2,310 of 1974) until 2003, the only contracts to explore and exploit hydrocarbons were the association contracts, in which Ecopetrol (NOC) (the sole hydrocarbon company authorized for the exploration and exploitation of hydrocarbons in Colombian territory at that time), would associate with a contractor who assumed 100% of the risks and costs of exploration activities. If a commercial discovery was made, the operation and expenses for the production of the field were shared with Ecopetrol.

There are still association contracts in force, entered prior to the creation of the ANH in 2003. However, most of these contracts have either been migrated to new contractual regimes or have expired due to termination or relinquishment. No new association contracts can be executed.

Exploration and Production (E&P) Contracts and TEA's

In 2003, the state made two fundamental changes to the country's hydrocarbons policy. First, it established the ANH as the sole regulatory entity responsible for managing Colombia's hydrocarbons, converting Ecopetrol into a hydrocarbon E&P company. Second, it introduced the E&P contract model and technical evaluation agreements (TEA), replacing the association contracts mentioned before.

E&P contracts grant the exclusive right to explore and exploit hydrocarbons within a specified area, during determined periods and under specific conditions, at the contractor's costs and risk. The contractor has total operational autonomy regarding the execution of the exploration and exploitation activities and will have the obligation to pay royalties and the compensations agreed in the contract for economic rights.

E&P contracts and its awarding process are regulated through the *acuerdos* issued by the ANH and contract models issued for each competitive process led by the ANH to allocate areas and contracts. Therefore, each E&P contract will be governed by the agreement and/or contract model in effect at the time of its execution.

The term of the phase(s) of each contract is defined in the terms of reference and the model contract of each competitive selection procedure, or in the *acuerdo* governing the awarding process. These elements shall be determined based on the nature and geographic location of the area, the category and the type of hydrocarbon.

In any case, E&P contracts comprise three phases: exploration, evaluation and production. Commonly, the exploration stage lasts up to six years (or up to nine years for unconventional and offshore fields) and it is typically divided into annual exploration stages. Following the exploration period, and assuming a discovery is made, the block enters an evaluation phase to determine its commercial potential. Once the evaluation is completed and commerciality is declared, the production period starts, which will last up to 24 years (or up to 30 years for unconventional and offshore reservoirs).

On the other hand, a TEA grants the contractor the exclusive right to develop technical evaluation operations with operational autonomy at its own cost and risk, seeking to appraise the hydrocarbon potential of an area under specific conditions, with the purpose of identifying the zones of prospective interest in the area by means of the execution of an exploratory program. The contractor has the first option to request the conversion of a TEA into one or more E&P contracts that cover the area of the TEA (or a portion thereof). The contractor can conduct evaluation activities for terms that vary between 18, 24 and 36 months, depending on the terms of reference of the ANH's bidding round.

Fiscal Regime and Government Takes: Taxes, Royalties and Pricing Regulations

In Colombia, contractors operating under E&P contracts with the ANH have the right to freely dispose of their share of production once the corresponding economic rights and royalties to the state have been paid. Royalties, regulated under Law No. 756 of 2002 and subsequent legislation, are payable in kind or in cash and are calculated primarily based on production volumes, the type of hydrocarbon (conventional or unconventional) and the contractual regime.

If an E&P contract is executed, it is probable that it will include the following additional economic benefits for the Colombian government. These benefits include: (i) participation in production, which is offered as part of the bid in competitive processes for exploration and exploitation areas; and (ii) entitlement to windfall profits or high-price participation and technological transfer contributions, according to the terms of each contract and ANH's contractual models and regulations.

From a tax perspective, oil and gas companies operating in Colombia are subject to the general corporate tax regime, including corporate income tax, value-added tax, and industry and commerce tax (ICA), with ICA obligations dependent on royalty payments. Companies engaged specifically in crude oil extraction may also face an additional income surtax, the rate of which varies according to average international crude oil prices during the relevant taxable year.

In certain cases, additional taxes may apply, such as the temporary special contribution for the Catatumbo region (effective only until December 31, 2025) and the National Carbon Tax, when crude oil qualifies as a fossil fuel based on its emission factor. Conversely, crude oil itself is not taxed by the National Gasoline and Diesel Fuel Tax.

Companies may also access special regimes such as free trade zones, along with tax incentives for environmental, scientific and technological investments.

Crude oil prices are free and determined by market dynamics and are generally referenced to international benchmarks such as West Texas Intermediate (WTI) and Brent crude. However, certain refined products are subject to domestic price stabilization mechanisms, most notably the Fuel Price Stabilization Fund (*Fondo de Estabilización de Precios de los Combustibles* – FEPC), which is designed to mitigate the impact of volatility in international oil prices on the domestic prices of gasoline and diesel.

Environmental Regulations

In Colombia, any project, work or activity that involves the use of renewable natural resources and/or that may affect the environment or the landscape, will require the interested party (beneficiary) to apply and obtain from the competent environmental authorities (national, regional or district) the required environmental licenses, concessions, permits and/or authorizations before starting the corresponding project.

These authorizations correspond to instruments of control and socio-environmental monitoring of projects, works and/or activities that require the use or exploitation, or that impact, renewable natural resources. These authorizations must be previously obtained from the environmental authorities for the use and exploitation of renewable natural resources in Colombia. Environmental administrative authorizations can cover various types, among which the following stand out:

- Environmental licenses
- Environmental permits (forest use permit, atmospheric emissions permit, groundwater prospecting permit, among others)
- Environmental concessions (surface water concession; surface or groundwater concession)

The regulations related to the environmental regime are found in the Regulatory Decree of the Environment and Sustainable Development Sector - Decree No. 1076.

Considering the above, any company seeking to undertake hydrocarbon projects must obtain an environmental license and, depending on the scale of the project and its characteristics, this license must be obtained from the ANLA or from the Autonomous Regional or Sustainable Development Corporations.

For the purposes of obtaining the environmental license, the interested party must prepare and submit to the competent environmental authority an environmental impact study (EIA) identifying the potential environmental impacts, corresponding mitigation measures and environmental compensation plans. In addition, compliance with the terms of reference issued for the hydrocarbon sector is mandatory.

The EIA in Colombia is subdivided into two sections: the diagnostic phase and the programmatic phase. In the diagnostic phase, the interested party must provide a detailed description of the project, its location, the socio-environmental baseline, the estimate of demand for resources required for the development of the project, the socio-environmental zoning of the project and the economic evaluation of the identified impacts. In the programmatic phase of the study, an environmental management plan (*Plan de Manejo Ambiental* (PMA)) must be presented, which includes all the measures aimed at controlling, mitigating, correcting or compensating the impacts identified in the diagnostic phase, including the contingency plans and programs, compensation and other requirements established by the applicable terms of reference.

In accordance with Colombian regulation, hydrocarbon projects also require the carrying out of a social license process to conduct participatory engagement with local communities and relevant stakeholders within the area of direct influence. This process includes providing timely and sufficient information regarding the project's scope, potential impacts and proposed mitigation measures. The proponent must facilitate participatory diagnosis sessions, allowing communities to identify social and environmental characteristics, potential impacts and management measures. In the case of ethnic communities, the process must comply with the applicable prior consultation procedures, ensuring the participation of community representatives and authorities, and documenting agreements reached. All evidence of community engagement and consultation must be annexed to the EIA submitted for licensing.

ECUADOR'S UPSTREAM OIL & GAS INDUSTRY

Hydrocarbon Reserves and Industry Players in Ecuador

Ecuador's crude oil reserves, as per the official data (2022), amount to 8,270 million barrels. Petroamazonas has informed that Block 43 (ITT) contains 1,670 million barrels, which represents an additional 82% of the actual reserves.

Ecuador has estimated natural gas reserves of 10,911 MMm^3, with Campo Amistad being the largest deposit with 167,000 million cubic feet in reserves.

Petroecuador and the Ministry of Energy and Mines control approximately 80% of oil production in Ecuador. Other industry players include, among others: Andes Petroleum, Consorcio Repsol, Gente Oil Ecuador Pte. Ltd., Gran Tierra Energy Inc., ENAP Sipetrol, Pacifpetrol, Sinopec, Petrobell S.A. – Grantmining S.A., Pluspetrol Ecuador B.V., Tecpecuador S.A. and Petrolia.

Hydrocarbon Jurisdiction in Ecuador

The Ministry of Energy and Mines (MEM) regulates all Hydrocarbon activities in the country, while the Hydrocarbon Control and Regulatory Agency is responsible for ensuring compliance with legislation and technical regulations. Most of the regulatory power is exercised by the MEM through the Vice Ministry of Hydrocarbons. Petroecuador EP is the public state company in charge of the exploration and production of hydrocarbons, as well as the crude oil transportation (via the SOTE oil pipeline). In addition, the OCP pipeline for heavy crude oil transport was originally built by a private company and reverted to the state in December 2024.

Hydrocarbon Licensing in Ecuador

The Ecuadorian Constitution provides equal treatment for national and foreign investors and grants constitutional protection to their rights. Hydrocarbon deposits located in national territory, including under the territorial sea, belong to the inalienable and imprescriptible heritage of the state. Thus, their exploitation will be subject to the guidelines of sustainable development and the protection and conservation of the environment.

The Hydrocarbon Law establishes that the state will explore and/or exploit hydrocarbon deposits directly through public companies. Exceptionally, the state may delegate these activities to national or foreign companies or consortiums with proven experience, as well as technical and financial capabilities. In these cases, the MEM may enter into participation contracts, service provision contracts for exploration and/or exploitation of hydrocarbons, or other contractual forms of delegation that are in effect in Ecuadorian legislation or commonly used in the industry at an international level, provided they do not contradict Ecuadorian legislation, which may be specified in the regulations of this law.

Hydrocarbons contracts grant exclusive rights to explore, develop and extract hydrocarbons. The exploration period may last up to four years, extendable for an additional two more years upon justification by the contractor and authorization from the MEM. The exploitation period may last up to 20 years, also extendable by the MEM.

Contracts for exploration and exploitation of natural gas grant an exploration period that may last up to four years, extendable for up to two additional years upon justification by the contractor and authorization from the MEM. After the exploration period and before the exploitation period begins, the contractor will have the right to a market development and infrastructure construction period necessary for such purpose, which may last five years, extendable according to the state interests, so that the contractor may commercialize the discovered natural gas. The exploitation phase may last up to 25 years and may also be extended by the MEM in line with the interests of the state.

Fiscal Regime and Government Takes: Taxes, Royalties and Pricing Regulations

Ecuador's oil & gas sector operates under a dual fiscal framework that includes both royalties and taxes.

Companies under participation contracts must pay a minimum royalty of 12.5% on gross oil production (and 16% for gas), while those under service contracts receive a fixed per-barrel fee, with the state retaining full ownership of the crude oil.

On the tax side, oil companies are subject to a 25% Corporate Income Tax and a 13% (raised to 15% for the 2025 fiscal year) value-added tax (which cannot be claimed back when exporting goods).

Additionally, a 5% remittance tax applies on payments made abroad (with some applicable exemptions), and a presumptive tax also applies if export revenues are not repatriated within 180 days of the transaction.

Environmental Regulations

Ecuadorian authorities exercise a very rigorous environmental control of hydrocarbon activities. The applicable legislation requires the submission of environmental impact assessments with government approval prior to the undertaking of any field activity. Projects must also comply with strict environmental operating standards and obtain an environmental license, a management plan and insurances or guarantee bonds to cover potential environmental liabilities. Environmental violations are subject to stiff penalties and may result in criminal charges. Remediation and reparation activities are required during the term of the contracts as well as prior to the abandonment of contract areas, in accordance with abandonment plans previously approved by the Ministry of Environment.

Ecuador has ratified the International Labor Organization Indigenous and Tribal Peoples Convention No. 169, which establishes the obligation of previous consultation to determine if the interests of native communities would be affected, prior to authorizing any exploration or exploitation activities comprising resources existing in areas where they live. The previous consultation process is implemented by the government. The process does not imply a veto right by indigenous communities, yet it may prohibit a project if it requires resettlement of communities from their lands to a different location.

MEXICO'S UPSTREAM OIL AND GAS INDUSTRY

Hydrocarbon Reserves and Industry Players in Mexico

Mexico's hydrocarbon industry remains a cornerstone of the country's energy matrix, with upstream activities concentrated in mature shallow-water fields in the Gulf of Mexico and onshore basins such as the Burgos Basin. According to the National Hydrocarbons Commission (CNH), as of early 2024, Mexico reported oil reserves of approximately 7.0 billion barrels and natural gas reserves of 12.5 trillion cubic feet.

Petroleos Mexicanos (Pemex) continues to be the dominant player in both exploration and production, accounting for over 90% of national oil output. However, since the 2013 Energy Reform, over 100 contracts have been awarded to private and foreign operators through CNH-led bidding rounds, fostering a more diversified upstream landscape. Notable international players include Shell, Eni, Wintershall Dea, Carso and Talos Energy, particularly in offshore deepwater blocks.

Hydrocarbon Jurisdiction in Mexico

Article 27 of the United States of Mexico Constitution establishes that all hydrocarbons located in the Mexican subsoil are the inalienable and imprescriptible property of the nation. These resources are not subject to concessions, and their exploration and extraction must be conducted either directly by the state or through assignments and contracts with state-owned enterprises or private entities, in accordance with the Hydrocarbons Law (*Ley de Hidrocarburos*) and its regulations.

Historically, regulatory responsibilities in the hydrocarbon sector were divided among several entities: The Ministry of Energy (SENER) was in charge of sectoral policy and planning; the CNH oversaw upstream regulation, including exploration and production contracts; and the Energy Regulatory Commission (CRE) supervised midstream and downstream activities, including transportation, storage and marketing of oil and gas products.

However, under the 2025 Energy Reform, published in the *Official Gazette of the Federation* on March 18, 2025, a significant restructuring of the regulatory framework was enacted. A new entity, the National Energy Commission (*Comision Nacional de Energía*, or CNE), was created to consolidate the functions previously held by CNH and CRE. The CNE now operates as a decentralized agency under SENER and is responsible for regulating, supervising and enforcing compliance across the entire hydrocarbon value chain.

Only legal entities authorized by the CNE—such as Pemex or private companies with approved contracts or permits—may lawfully engage in exploration and extraction activities. No local state or municipal authority may directly acquire or exercise such rights. This centralized and federally administered framework is designed to preserve the nation's constitutional right of ownership over hydrocarbons while ensuring uniform legal and technical standards across the country.

Hydrocarbon Licensing in Mexico

Following the 2013 Energy Reform, Mexico introduced a contractual regime allowing the government to enter into various types of contracts with private parties for the exploration and extraction of hydrocarbons, pursuant to the Hydrocarbons Law. These contracts were awarded through public bidding rounds conducted by the CNH, or through direct award to Pemex. The main types of contracts currently in effect include license contracts and production sharing contracts (PSCs).

Contracts are generally awarded through competitive bidding rounds (*rondas*) – 1 to 3.3 between 2015 and 2018 – granting exclusive rights to explore and extract hydrocarbons within a contractually defined area.

Exploration periods typically last up to four years, renewable for two additional years, with the possibility of transitioning to a 25-year extraction phase, extendable up to 30 or even 35 years, depending on the type of field and investment performance.

Fiscal Regime and Government Takes

Royalties payable under exploration and production (E&P) contracts are established in the Hydrocarbons Revenue Law (*Ley de Ingresos sobre Hidrocarburos*). Royalties are defined as the consideration payable to the Mexican government based on the contractual value of the oil, considering the formula established in said federal law.

Pursuant to Section 24 of the Hydrocarbons Revenue Law, when the contractual value of crude oil is below US$ 48 per barrel, the applicable fixed royalty is 7.5%. If it is equal to or greater than US$ 48, the royalty is determined based on a formula that takes price into account. Under each E&P contract, royalties are adjusted annually based on the U.S. consumer price index. Royalties are paid for other hydrocarbons, such as natural gas (associated or nonassociated) and condensates.

In addition to taxes and royalties, depending on the type of E&P contract, other kinds of payments to the government may apply. In the case of licenses, these may include signing bonuses, a rental fee known as the "contractual fee for the exploratory phase" and a fee applied to the value of the oil contract. In the case of PSCs, in addition to the rental payment and royalties, the state will receive a percentage of operating profits. Other applicable taxes include income tax (30%) and local taxes, such as the Special Tax on Production and Services applied to gasoline and diesel.

Environmental Regulations

Hydrocarbon exploration and exploitation in Mexico is subject to rigorous environmental and safety regulations. Before beginning any exploration or development program, the operator must submit an environmental impact statement to the Agency for Safety, Energy and the Environment, which assesses risks to terrestrial and marine ecosystems. If water use is required, the corresponding permit is processed through the National Water Commission, while if the project affects protected natural areas, prior authorization is required from the National Commission for Protected Natural Areas.

PERU'S UPSTREAM OIL & GAS INDUSTRY

Hydrocarbon Reserves and Industry Players in Peru

Peru's relationship with the oil industry goes back to 1863, when the first South American oil well was drilled in the northwest coast near the border with Ecuador, where we still find producing oil and gas (O&G) blocks. In the 1970s there were some significant discoveries of crude oil in the northern Amazon jungle of the country, and by around 1980, the country's crude oil production reached 200,000 barrels of oil per day (BOPD). However, a lack of significant exploration activities has led to a decline in the country's crude oil production, which currently stands at 45,000 BOPD.

The discovery of 18 trillion cubic feet (TCF) of natural gas in the Camisea fields (Blocks 88, 56, 57 and 58) located in the Cusco region, together with the construction of a dual gas and liquids transportation system across the Andes, marked an important milestone in Peru's O&G industry. The Camisea fields began production in 2004, delivering natural gas to the capital city of Lima and liquids to the southern port of Pisco. In addition, private investors built a liquid natural gas (LNG) plant 170 kilometers south of Lima, enabling the export of natural gas. Part of this LNG is currently used for natural gas distribution by truck to the northern and southern regions of the country. Key players in the Peruvian upstream natural gas industry are Pluspetrol, Hunt Oil Company, SK Corporation, Tecpetrol, Repsol, Sonatrach and CNPC.

In recent years, there has been a growing interest in the potential of offshore blocks. Occidental Petroleum, through its wholly owned subsidiary Anadarko, is preparing to its first exploration well in one of three offshore blocks it holds under license contracts off the northern coast of Peru. Additionally, companies carrying out surface studies under offshore technical evaluation agreements (TEAs) aiming at determining the hydrocarbon potential of certain areas, include Total Energies, Condor Oil and Jaguar Exploration. A TEA grants its holder the preemptive right to enter into a license contract, should the studies be positive.

Hydrocarbon Jurisdiction in Peru

The Ministry of Energy and Mines (MINEM) regulates all hydrocarbon activities in Peru, while OSINERGMIN is the agency responsible for ensuring compliance with government safety and technical regulations. While some minor MINEM responsibilities have been delegated to regional authorities, most of the regulatory power is exercised by MINEM through the Vice Ministry of Hydrocarbons and its General Directorate of Hydrocarbons. Perupetro S.A. is the state-owned agency in charge of granting exploration and production rights through license contracts. These contracts are fair and balanced for both parties and have become easily acceptable for investors, who tend to focus on negotiating only the work program and royalties.

Hydrocarbon Licensing

The Peruvian Constitution guarantees equal treatment for domestic and foreign investors, and provides constitutional protection against political and legislative interference with the terms of contracts entered into with the government. Within this constitutional framework, Hydrocarbons Law No. 26,221 and many specific regulations under it regulate oil and gas activities in the country. License contracts grant exclusive rights to explore, develop and extract hydrocarbons for up to 30 years (crude oil) and natural gas (40 years), with a seven-year exploration phase (extendable up to 10 years). These contracts grant tax stability, guarantee free access to foreign currency at free market rates, and provide exemption from export duties, the free disposal of production in both domestic and export markets, foreign currency accounting and other benefits.

Fiscal Regime and Government Takes: Taxes, Royalties and Pricing Regulations

Contractors under license contracts can freely dispose of their production in exchange for paying a royalty in U.S. dollars to Perupetro. Royalties are normally based on an "R" factor (accumulated revenues/accumulated expenditures) and range from 15% upwards, although it is possible to negotiate lower royalties for nonconventional areas, blocks with declining production or when there is a lack of transport infrastructure for produced hydrocarbons. Alternative methodologies for calculating royalties include: (i) accumulated production by field with price adjustment; (ii) economic results; and (iii) scale of production.

License contractors are subject to the income tax regime in force at the time their contract is signed for the entire duration of their licenses. The current income tax rate is 29.50% on net income and an additional 5% on profit remittances. Value-added tax is set in 18%. Peru does not impose any export taxes, foreign currency limitations or price controls. Hydrocarbons prices are subject to supply and demand.

Environmental Regulations

Peruvian authorities exercise a very rigorous environmental control for hydrocarbon activities. The Regulations for Environmental Protection in Hydrocarbon Activities approved by Supreme Decree No. 039-2014-EM, as amended, require oil and gas contractors to submit environmental impact assessments for government approval prior to undertaking any field activity and to comply with strict environmental operational standards. Environmental violations are subject to substantial penalties, enforced by a control entity called OEFA. Remediation activities are mandatory during the term of a license and must be conducted prior block abandonment, according to previous government-approved abandonments plans.

Peru is a signatory to the International Labour Organization’s Indigenous and Tribal Peoples Convention No. 169, which mandates a prior consultation process with indigenous communities whose rights may be affected before the government may authorize any exploration or production activity in areas where they live. This consultation is conducted by the government, and while it is mandatory, it does not confer veto power on indigenous communities.

URUGUAY'S UPSTREAM OIL AND GAS INDUSTRY

Hydrocarbon Reserves and Industry Players in Uruguay

To date, Uruguay does not have any proven hydrocarbon reserves. Nevertheless, its offshore waters on the South Atlantic Ocean have recently become an interest zone for major industry players worldwide, given that they share great similarities with the Namibian basin, where Total and Shell made large discoveries in early 2022 (reserves estimated at over 11 billion barrels). In fact, both areas were adjacent during the Early Cretaceous Period, before drifting off to their current locations.

These developments have caused the totality of the offshore areas offered for exploration by the Uruguayan government to be picked up by different entities. Currently, Chevron, Shell, YPF, APA Corporation and Challenger Energy Group are the companies present in Uruguay.

There are a total of seven areas (numbered OFF-1 through 7), which are large blocks (around 15,000 square kilometers each), three of which are in shallow waters (20 to 1,000 meters) and the remaining four in deep waters.

All areas are currently in the exploration phase, and to date no exploratory wells have been drilled, although at least one has been committed by APA. There is ample opportunity for companies interested in partnering with the existing licensees in some of the areas through farm-out agreements; several firms have publicly stated that they are looking for partners going into the next phases of their contracts.

Offshore prospecting in Uruguay is not unprecedented. The first explorations in the country date back to the 1970s, and in 2016, Total drilled what was at the time the deepest well ever recorded, at 3,400 meters underwater and a further 2,400 meters below basin floor, which came up dry. It is the hope of many in the industry that this time around, armed with better technology and more information, results may be positive.

Hydrocarbon Jurisdiction in Uruguay

Uruguay is a unitary country, and as such its natural resources are administered by the national state. By law, all subsoil resources and extracted substances are state-owned, but contractors can be licensed to drill them and keep a portion of the produce by way of compensation.

ANCAP, the state-owned oil company, is statutorily designated as the competent body to carry out all hydrocarbon-related activities and is legally authorized to enter into agreements with third parties to achieve such purposes.

Hydrocarbon Licensing in Uruguay

Pursuant to Uruguayan law (mainly, Decree-Law No. 14.181 and Decree-Law No. 15.242, as amended) ANCAP is authorized to enter into agreements with third parties—domestic or foreign, public or private—to carry out hydrocarbon-related activities, which must be approved by the executive branch.

Further requirements are: (i) that contractors be selected through a public bidding process (although they may be contracted directly with the executive branch's approval); (ii) that the executive branch consents to the bidding and approves the draft contract; and (iii) that the compensation in kind to be provided to the contractor is subject to ANCAP's right to acquire hydrocarbons that are necessary to supply the domestic market.

With that framework, ANCAP has drafted a model contract that is balanced and has not been objected to by any industry players. It provides for a first exploration phase with very low obligations, and the option to advance with the drilling of an exploratory well thereafter. ANCAP's right to acquire hydrocarbons for the domestic market is also diluted through the obligation to provide a one-year advance notification, and to reimburse it at market prices (also, the Uruguayan domestic market is small, consuming around 40,000 billion barrels per day).

The term of the contract is 30 years, extendable for a further 10 years. Exploitation of hydrocarbons may take place for a maximum of 25 years.

Fiscal Regime and Government Takes: Taxes, Royalties and Pricing Regulations

Exploration of hydrocarbons in Uruguay is tax-exempt, and Uruguayan law places no royalties on extracted hydrocarbons.

In the exploration/exploitation contracts that have been signed, the contractor's compensation is divided into two tranches: cost oil and profit oil. Cost oil compensates all investments made during the exploration and exploitation phases, capped at 60% of the extracted oil and 80% of the extracted gas. Profit oil, which is the subsequent portion of hydrocarbons, is to be divided between the contractor and the state according to an "R" factor, which is biddable and thus varies across the different contracts, but ANCAP's share does not exceed 30% of the total in case of oil.

The contractor's share of the profit oil may be freely disposed of, with no export restrictions whatsoever. It is only subject to income tax at a flat 25% rate. The hydrocarbons are to be valued at international market prices.

Uruguay has a free foreign exchange market and allows for the unrestricted repatriation of profits and dividends.

Environmental Regulations

Uruguay subjects the oil and gas sector to compliance with its environmental regulations, which basically entail the need to obtain a prior environmental authorization before any activities can be conducted (for instance, in the offshore sector, individual authorizations need to be obtained for 3D seismic activities, drilling an exploratory well and commencing production). The environmental authorization process includes the need to conduct a full environmental impact study and provides for the carrying out of public hearings.

In the offshore contracts that have been signed, contractors assume specific decommissioning obligations, and Uruguayan environmental legislation requires that contractors assume mitigation commitments aimed at restoring the site to its original condition after the work is finalized.

VENEZUELA'S UPSTREAM OIL & GAS INDUSTRY

Hydrocarbon Reserves and Industry Players

Venezuela's crude oil reserves are reported at 303,806 million stock tank barrels (MMSTB) by the Ministry of Hydrocarbons, and 303.01 billion barrels by OPEC.[2] The Ministry of Hydrocarbons estimates Venezuela's gas reserves at 200.3 trillion cubic feet (TCF), while OPEC reports them as 5.48 trillion standard cubic meters. Pursuant to the Venezuelan Constitution of 1999, amended in 2009, the Master Act of Hydrocarbons of 2006 (MAH) and the Master Act of Gaseous Hydrocarbons of 1999 (MAGH), all oil and gas reserves within Venezuelan territory are owned by the nation, with the state exercising control over their exploitation and with stricter limitations on private sector involvement in oil-related activities than in gas.

Significant control over the hydrocarbon industry is exerted by Petróleos de Venezuela, S.A. (PDVSA), the state-owned company, created in 1975. It operates as a private law corporation under a public law regime and is overseen by the Ministry of Popular Power for Hydrocarbons. The federal executive branch plays a direct role in its corporate operations, making PDVSA the most significant player in Venezuela's hydrocarbon sector, including its gas industry branches.

Other industry players include Chevron (until May 27, 2025, for winding down operations only, pursuant to OFAC's General License 41B); Repsol; ENI S.p.A.; Maurel & Prom; ONGC Videsh Limited; and China Petroleum & Chemical Corporation (Sinopec), among others.

Hydrocarbon Jurisdiction

In Venezuela, the Ministry of Popular Power of Hydrocarbons is the primary authority for the oil and gas sector, responsible for policymaking, regulation and oversight, including inspection of hydrocarbon activities. Additionally, companies wishing to challenge administrative acts by the executive may pursue administrative appeals directly before the executive branch itself or file judicial claims before the administrative-contentious jurisdiction, a specialized court system for cases involving public power authorities, such as the Ministry and state-controlled companies like PDVSA. The competent court is determined by the claim's value, and while arbitration is recognized in the hydrocarbon laws, bilateral investment treaties provide additional protections.

Hydrocarbon Licensing

Regarding oil, the MAH designates certain hydrocarbon-related activities as "primary activities" for the purposes of said law. These are activities "relating to the exploration [...] of hydrocarbons deposits [...], their extraction [...], their collection, transportation and initial storage [...]" The Venezuelan state alone is permitted to carry out these primary activities, "either directly through the National Executive or via companies wholly owned by the latter." It may also do so in partnership with "joint ventures" in which the state owns more than 50% of the stock capital and thus has a controlling interest in the joint venture's decision-making process. However, refining and commercialization activities can be carried out by private actors without the participation of the state, pursuant to the MAH. The MAHG allows the Venezuelan state, either directly, through state-owned entities, or in partnership with private national or foreign entities, to conduct activities related to non-associated gas exploration, exploitation, extraction, storage, utilization, processing, industrialization, transportation, distribution and trade, both domestically and internationally. This also applies to gas produced in association with oil or other fossil fuels. Private companies must obtain a license from the Ministry of Hydrocarbons, which is granted for a maximum of 35 years, with a potential extension of up to 30 years.

Fiscal Regime and Government Takes: Taxes, Royalties and Pricing Regulations

Venezuelan income tax for hydrocarbon exploitation and related activities such as refining, transportation or the purchase of hydrocarbons for exploitation is set at 50%, although companies operating across the entire or partial non-associated gas value chain, or exclusively engaged in heavy crude oil refining or upgrading, are exempt from this rate. The general value-added tax is 16%, with a zero percent rate applied to natural hydrocarbon sales by joint ventures to PDVSA or its subsidiaries. Additionally, the oil industry is subject to several specific taxes established under the MAH, including:

1. Surface Tax: Applied to the part of the surface extension of the geographical area, granted that it is not being exploited, at an equivalent rate of 100 tax units (as of May 2025, a tax unit is equivalent to USD 0.10) for each square kilometer or fraction thereof for each year elapsed.

2. Excise Tax: 10% of the value of each cubic meter of hydrocarbon-derived products produced and used as fuel in operations.

3. General Consumption Tax: For each liter of product derived from hydrocarbons sold in the domestic market, at a rate between 30% and 50% of the price paid by the final consumer.

4. Extraction Tax: One-third of the value of all liquid hydrocarbons extracted from any reservoir.

5. Export Registration Tax: 0.1% of the value of all oil exported from any port in the national territory, calculated on the price at which it is sold to the buyer.

6. Windfall profits tax (for “extraordinary” and “exorbitant” prices): Based on the difference between the prices established in the Venezuelan national budget and the monthly average of the international prices for the basket of Venezuelan hydrocarbons.

The general regime on royalties is set at 30% applied to oil production; however, this rate can be reduced to 20% if it is necessary to make the extraction economically viable. For gas extracted from any reservoir and not reinjected, a royalty of 20% of the extracted volume is levied. The state reserves the right to demand both royalties either in kind or in cash.

In addition to the specific taxes established under the MAH and MAGH, oil and gas activities could also be subject to the following taxes:

Tax provision	Applicable rate
Income tax, oil	50%
Income tax, gas	34%
Social and endogenous tax	1% of net income
Social and anti-drug investment tax	1% of net income
Science and technology tax	0.5% of gross income
Alternative minimum tax (IMA, for its acronym in Spanish)	50% of Gross Oil Revenue

Investment tax credit (this investment allowance was removed from the legislation)	12% tangible investment
Depreciation	10 years, straight line

Since the enactment of the Anti-Blockade Law, alternative forms of contracting for the exploitation of oil and gas have been developed, allowing companies to explore, develop and produce hydrocarbons in a defined area in exchange for a share in production. Generally, these alternatives involve more favorable fiscal terms, subject to specific terms and conditions.

Environmental Regulations

The Venezuelan Constitution enshrines sustainable development as a referential framework and guiding principle for all state activities, including those related to oil and gas. Within this referential framework, environmental regulations, some of which are based on international agreements ratified by Venezuela, impose several obligations applicable for oil and gas activities, which include:

1. The obligation to implement a safe environmental policy, including an evaluation of environmental impacts (Art. 23.5, Environmental Organic Law).

2. The obligation to conduct an environmental impact assessment (Article 6.2 and 8 Decree N°1.257. Regulations for the Evaluation of Activities Susceptible of Degrading the Environment).

3. The obligation to obtain certain permits and authorizations to carry out certain activities that could harm or pose a risk to the environment.

4. The obligation to perform an integral management of water, which comprises carrying out risk analysis, where applicable (i.e., in the production phase) (Articles 11.5, Water Law).

5. The obligation to prepare a contingency plan to ensure environmental safety and prevent risks to biodiversity (Articles 2.7, 2.9 and 6, Law on Biodiversity).

6. The obligation to inform of the risks associated with hazardous substances, materials and wastes generated, used or managed in certain activities (Article 16, Law on Hazardous Substances, Materials and Wastes).

7. The obligation to carry out necessary environmental protection activities in oil and gas operations (MAH and MAGH).

Failure to comply with the environmental regulations listed above could result in potential penalties ranging from fines and suspension of operations to imprisonment under the Criminal Environmental Law.

THE UNITED STATES' UPSTREAM OIL & GAS INDUSTRY

Hydrocarbon Reserves and Industry Players in the U.S.

The United States holds significant hydrocarbon reserves, ranking among the top global producers of both oil and natural gas. The most prominent resource basins include the Permian Basin in Texas and New Mexico, the Bakken Formation in North Dakota and Montana, the Eagle Ford Shale in South Texas, and the Marcellus Shale in the Appalachian region. Technological advancements in hydraulic fracturing (fracking) and horizontal drilling have unlocked vast quantities of previously inaccessible oil and gas, transforming the U.S. into a net exporter of energy in recent years.

The U.S. upstream sector is highly fragmented compared to other major producing countries. While large multinational corporations play critical roles, the industry also includes a substantial number of independent exploration and production (E&P) companies. These independents are particularly influential in the shale plays, often driving innovation and shaping production trends. Service companies also play a critical role by providing drilling, completion, and other essential support services.

Hydrocarbon Jurisdiction in the U.S.

Unlike many countries where the federal government owns all subsurface minerals, the U.S. legal framework is unique in that hydrocarbon ownership can be private, state, or federal. Private individuals and companies can own mineral rights, especially in certain states like Texas, allowing them to lease directly to oil and gas companies. In contrast, federal lands are managed by the Bureau of Land Management ("**BLM**") and other agencies, while state lands are overseen by respective state land offices or commissions.

Jurisdictional authority is split accordingly. Operations on federal lands are subject to federal regulations and oversight, while operations on private or state lands are primarily governed by state laws and regulations. Coastal waters are also divided: generally, states control up to three nautical miles offshore (or up to nine miles for Texas and Florida in the Gulf of Mexico), while the federal government controls the Outer Continental Shelf beyond that.

As such, companies seeking to engage in hydrocarbon exploration and production must navigate a multifaceted regulatory landscape, ensuring compliance with a myriad of legal requirements at both the federal (e.g., BLM, EPA) and state levels.

Hydrocarbon Licensing

In the U.S., hydrocarbon exploration and production rights are typically obtained through leasing rather than traditional licensing rounds. In most states, mineral rights can be severed from the surface estate. On private land, terms are highly flexible and can vary significantly depending on market conditions and the bargaining power of the landowner and/or mineral rights owner. Severed estates are less common on federal and state lands, and leases are generally awarded through competitive bidding processes, administered by agencies like the BLM for federal leases or state land offices for state-owned resources. State authorities also play a significant role in hydrocarbon licensing, particularly for activities on state-owned lands and waters. Each state has its own regulatory framework, which may include additional permits and approvals beyond those required at the federal level.

Leases commonly stipulate a primary term (often 3–5 years) during which drilling must occur to maintain rights, after which a producing well can hold the lease in force through production. Leasing processes also usually involve bonus payments (upfront fees), rental payments (annual payments on non-producing acreage), and obligations like minimum work commitments or environmental safeguards.

Fiscal Regime and Government Takes: Taxes, Royalties, and Pricing Regulations

The U.S. fiscal regime for upstream oil and gas is decentralized and market-driven, with key revenue streams consisting of royalties, taxes, and lease bonuses rather than strict government profit-sharing. On federal lands, producers pay a royalty of typically 12.5% to 18.75% of the value of production, while private leases often command higher rates negotiated individually. Severance taxes, imposed by producing states, vary widely. For example, Texas charges 4.6% on oil and 7.5% on gas, while North Dakota has a combined oil extraction and production tax of around 10%.

Unlike many other countries, the U.S. generally does not regulate the price at which oil and gas are sold; prices are determined by market forces. However, producers may face local pricing dynamics due to pipeline constraints, quality differentials, and regional supply and demand imbalances. Additionally, companies are subject to federal and state corporate income taxes, though deductions and credits (such as for intangible drilling costs) can significantly affect effective tax rates.

Environmental Regulations

Environmental regulation of upstream oil and gas activities in the U.S. is robust and multi-layered, involving federal, state, and sometimes local authorities. Key federal laws include the Clean Water Act, Clean Air Act, and the National Environmental Policy Act ("**NEPA**"), with agencies like the Environmental Protection Agency (EPA) and the U.S. Army Corps of Engineers playing major roles. Drilling operations must comply with rules regarding air emissions, water discharges, waste management, and habitat protection.

States often impose additional, and sometimes stricter, environmental requirements tailored to their local ecosystems and public concerns. For instance, states like Colorado and New Mexico have passed tight regulations on methane emissions from oil and gas facilities. Environmental considerations also impact the permitting process for drilling and infrastructure development, especially on federal lands where Environmental Assessments (EAs) or Environmental Impact Statements (EISs) under NEPA are often mandatory before drilling can proceed. Increasingly, regulatory attention is being focused on induced seismicity related to wastewater disposal and on broader climate impacts.

LEGAL FRAMEWORK FOR THE OIL AND GAS UPSTREAM INDUSTRY

SUBJECT	ARGENTINA	BRAZIL	COLOMBIA	ECUADOR	MEXICO	PERU	URUGUAY	USA	VENEZUELA
Current Reserves/Resources	Crude Oil Reserves: 477.27 MMm^3/3 BBO Resources: 774.37 MMm^3/4.87 BBO	Crude Oil Reserves: 2,678.80 MMm^3/16.84 BBO Resources: 4,639.60 MMm^3/29.18 BBO	Crude Oil Total Reserves: 1P: 321 MMm^3/ 2.02 BBO 2P: 423.4 MMm^3/ 2.66 BBO 3P: 511.1 MMm^3/ 3.22 BBO	Crude Oil Reserves: 1,314.50 MMm^3/8.27 BBO	Crude Oil Reserves: 1P: 1,332.7 MMm^3/ 8.38 BBO 2P: 2,467.3 MMm^3/ 15.53 BBO 3P: 3,677.8 MMm^3/ 23.15 BBO	Crude Oil Reserves: 51.67 MMm^3/0.33 BBO Prospective Resources: 5,290.62 MMm^3/33.27 BBO	N/A	Crude Oil Reserves: 7,679.41 MMm^3/48.32 BBO	Crude Oil Reserves: (i) Ministry of Hydrocarbons: 48,310.50 MMm^3/ 303.81 BBO; (ii) OPEC: 48,178.12 MMm^3/303.01 BBO
	Gas Reserves: 487,472 MMm^3/17.2 TCF Resources: 909,158 MMm^3/32.12 TCF	Gas Reserves: 546,022 MMm^3/19.28 TCF Resources: 740,505 MMm^3/26.15 TCF	Gas Total Reserves 1P: 67,195.8 MMm^3/ 2.37 TCF 2P: 84,185.8 MMm^3/ 2.97 TCF 3P: 104,545.6 MMm^3/3.69 TCF	Gas Reserves: 10,911 MMm^3/0.385 TCF	Gas Reserves: 1P: 348,296.3 MMm^3/12.30 TCF 2P: 660,748.6 MMm^3/23.30 TCF 3P: 655,687.5 MMm^3/23.15 TCF	Gas Reserves: 223,135 MMm^3/7.88 TCF Prospective Resources: 1,223,279 MMm^3/ 43.20 TCF	N/A	Gas Reserves: 19,579,908.8 MMm^3/691 TCF	Gas Reserves: (i) Ministry of Hydrocarbons: 200.30 TCF; (ii) OPEC: 5.48 1,000 billion standard m^3
Operating International Oil Companies (IOCs) and National Oil Companies (NOCs)	IOCs: TotalEnergies, Chevron, Shell, Pan American Energy, Equinor, Harbour Energy, Wintershall DEA, CNOOC, etc. NOCs: YPF	IOCs: TotalEnergies, Chevron, Shell, Equinor, CNOOC, Repsol, Perenco, ExxonMobil, GALP, QatarEnergy, etc. NOCs: Petrobras, PPSA	IOCs: Parex Resources, Gran Tierra Energy, Frontera Energy, GeoPark, Chevron Petroleum Colombia, ExxonMobil, Perenco, TotalEnergies, Petrobras, Shell. NOCs: Ecopetrol, Reficar, Cenit, Hocol and Oleoducto de los Llanos Orientales	IOCs: Andes Petroleum, Consorcio Repsol, Gente Oil Ecuador Pte. Ltd., Gran Tierra Energy Inc., ENAP Sipetrol, Pacifpetrol, Sinopec, Petrobell S.A. – Grantmining S.A., Pluspetrol Ecuador B.V., Tecpecuador S.A. and Petrolia NOCs: Petroecuador	IOCs: BP, TotalEnergies, Shell, Chevron, Repsol, ENI, Wintershall DEA NOCs: PEMEX	IOCs: TotalEnergies, CNPC, Repsol, Pluspetrol, Anadarko (Occidental Petroleum), Perenco, Hunt Oil, Sonatrach, etc. NOCs: Petroperu S.A.	IOCs: Chevron, Shell, APA Corporation, Challenger Energy Group NOCs: YPF	IOCs: ExxonMobil, Chevron, ConocoPh Foreign-based IOCs: BP, Shell, TotalEnergies	IOCs: Chevron (until May 27, 2025 for winding down operations only per OFAC's General License 41B); Repsol; ENI S.p.A.; Maurel & Prom; ONGC Videsh Limited; China Petroleum & Chemical Corporation (Sinopec); etc. NOCs: PDVSA and its subsidiaries, including PDVSA-Gas
Available Types of Resources	Conventional, unconventional and offshore oil and gas	Conventional, unconventional and offshore oil and gas	Conventional, unconventional and offshore oil and gas	Conventional and offshore oil and gas	Conventional, shallow water, deepwater, and unconventional oil and gas	Conventional and offshore oil and gas	N/A	Conventional, unconventional, shallow water, and deepwater	Conventional and unconventional oil, and offshore gas

	ARGENTINA	BRAZIL	COLOMBIA	ECUADOR	MEXICO	PERU	URUGUAY	USA	VENEZUELA
Rights Granted Over Hydrocarbons	Exploration permits, production concessions and transportation authorizations	Exploration and production (E&P) rights under concessions and production sharing agreements, and transportation and distribution authorizations	E&P contracts grant the exclusive right to explore and exploit hydrocarbons, within a specific area and during determined periods. Within association contracts the contractors assumed 100% of the exploration risk and cost, and upon a commercial discovery, production operations and costs were shared with Ecopetrol. Some are still in force, entered prior to the creation of ANH in 2003, yet no new association contracts can be executed), Technical Evaluation Agreements (TEA) grants the contractor the exclusive right to develop technical evaluation operations.	Contracts for the exploration and exploitation of hydrocarbons (several contractual figures: production sharing, service provision, association, among others)	Licenses, production sharing contracts profit sharing contracts, and allocations (*asignaciones*) for PEMEX	License contracts and service contracts entered with Perupetro for exploration and/or production activities; TEA for exploration works and studies that aim to determine certain areas' potential. TEA grants a preemptive right to sign a license contract	Exploration permits and production concessions	Exploration, development and production, surface access rights, logistics, marketing and sale, decommissioning and environmental rights/obligations	Oil: Joint ventures for both upstream and downstream activities. Private contracts under exceptional circumstances derive from international sanctions. Service contracts Gas: Fully private companies permitted for any activity under licenses or permits
Terms	Onshore conventional concessions: 25 years Onshore unconventional concessions: 35 years Offshore concessions: 30 years	Concession regime: 27 years Production sharing regime: 35 years	The term of the phase(s) of each contract is defined in the terms of reference and the model contract of each competitive selection procedure, or in the "*acuerdo*" governing the procedure. E&P contracts: (i) exploration, usually 6 years (or 9 years for unconventional and offshore fields); and (ii) production, up to 24 years (or 30 years for unconventional and offshore reservoirs). Association contract's term may vary in each agreement. TEA's: Terms may vary between 18, 24, and 36 months, depending on the terms of reference of the ANH's bidding round.	Hydrocarbon contracts: 24-26 years Gas contracts: 29-31 years	PSC: 30 years (renewable for 10 years) Licenses: 35 years (renewable for 15 years)	License contracts and service contracts: exploration term of up to 7 years (extendable for 3 more years), and production term of 30 years for oil and 40 years for natural gas from contract signature TEA: 24 months	Offshore concessions: 30 years, extensible for 10 more	Vary by type and duration (e.g., exploration 3-10 years, production 20-30 years)	Joint ventures for a term of up to 25 years, extendable for up to 15 more years

	ARGENTINA	BRAZIL	COLOMBIA	ECUADOR	MEXICO	PERU	URUGUAY	USA	VENEZUELA
Royalty Rate	Negotiable on each bidding process (with a reference rate of 15%) Concessions pre-2024: generally 12%	Concession regime: Depends on production amount (with a range of 5% and 10% on the production amount) Production sharing regime: Fixed at 15% of production amount	Progressive scale based on monthly average daily production per field at wellhead: (i) crude oil production: generally between 8% and 25%; and (ii) natural gas production: (a) onshore and offshore (≤1,000 feet deep): 80% of applicable crude oil royalty (*1 barrel of oil = 5,700 cubic feet of gas*); (b) offshore (>1,000 feet deep): 60% of applicable crude oil royalty (*1 barrel of oil = 5,700 cubic feet of gas*) Additional economic benefits for the Colombian government in E&P contracts: (i) participation in production, offered as part of the bid in competitive processes for exploration and exploitation areas; and (ii) entitlement to windfall profits or high-price participation.	Production royalties (Hydrocarbons Law): (i) Rate: minimum of 12.5% of gross oil production and 16% for gas production (ii) Applies to: participation contracts (iii) Purpose: direct compensation to the state for resource extraction Service contract payments (not a royalty per se, but a cost-based compensation model): (i) Rate: Fixed fee per barrel (e.g., $35), negotiated in the contract (ii) Applies to: service contracts where the state retains full ownership of the oil	PSC government take: 65%-80% of production value Onshore service licenses: 7.5% royalty	Based on "R" factor (accumulated revenues/ accumulated expenditures) Ranges from 15% upwards, although it is possible to negotiate lower royalties for nonconventional areas, blocks with declining production and lack of transportation infrastructure for the produced hydrocarbons Alternative methodologies: accumulated production by field with price adjustment, economic results and scale of production	0%	Depends on the jurisdiction, type of land ownership (federal, state, or private), and negotiation Generally, between 12 – 25%	30% of the oil produced, which may be reduced to 20% to make extraction cost-effective; and 20% of the volumes of gas extracted from any reservoir and not reinjected
Production Tax (Canon)	Annual fee of an ARS 4.500 (USD 4.15) per km^2 calculation, based on the concession area	Special participation: for high volumes of production under the concession regime	There is no production tax However, as mentioned above, royalties are applicable to the oil and gas industry	N/A	PEMEX shall pay 30% tax on the value of crude oil extracted and 11.62% tax on the value of natural gas extracted IOCs pay a fixed monthly fee as the exploration phase surface fee based on contracted area (no production): (i) First 60 months: $1,150 MXN/km² ($57.50 USD/km²/month) (ii) From month 61 onward: $2,750 MXN/km² ($137.50 USD/km²/month.)	There is no production tax The government pays a canon from the collected income tax and the collected royalties to the regional governments and municipalities within the area of influence of the oil and gas project	0%	There are production taxes, although it may go by different names (i.e., severance tax) Generally, these taxes are imposed by state governments and are levied on the volume or value of oil and gas produced, regardless of profitability	

	ARGENTINA	BRAZIL	COLOMBIA	ECUADOR	MEXICO	PERU	URUGUAY	USA	VENEZUELA
General Taxes	Income tax: 35% Value-added tax (general rate applicable): 21% Gross turnover tax (varies in each province): generally around 3%	Income tax: 34%, composed of: (i) IRPJ (Corporate Income Tax) of 25% (including a 10% surtax on profits above BRL 240,000/year); and (ii) CSLL (social contribution on net profit) of 9% ICMS (tax on the circulation of goods and services): A state-level tax that varies generally between 17% and 25% for certain products or in specific states. IPI (tax on industrialized products): A federal tax levied on industrialized goods, typically ranging from 0% to 15%, depending on the product. Brazil has a special custom incentive called REPETRO, which suspends taxed for the import of equipment destined to the E&P activities.	General Corporate Income Tax rate of 35%. An additional surtax applies specifically to companies engaged in crude oil extraction of 0%, 5% or 10%, added to the nominal income tax rate, depending on the annual average crude oil price during the corresponding taxable year Value-added tax: general rate of 19%. Generally, exports of tangible goods are exempt from VAT, enabling recovery (offset) of VAT paid throughout the production chain Industry and Commerce Tax (ICA): The obligation to pay ICA depends on whether the amount payable for ICA to the relevant municipality exceeds the royalties. Special contribution for the Catatumbo region: explained in “Export Taxes” below National Carbon Tax: May be triggered if crude oil qualifies as a fossil fuel, determined based on the greenhouse gas emission factor for each fuel type	Corporate Income Tax: 25% Value-added tax (general rate applicable): 13% (increased to 15% by presidential decree until December 2025). Remittance tax (on payments made abroad when importing goods or services -among other transactions-): 5%. Some exemptions apply (e.g., dividends)	Income tax: 30% Value-added tax: 16% on taxable services	Income tax: 29,5% on net income Value-added tax: 18% Remittance of profits: 5%	Income tax: 25%	Corporate Income Tax in the U.S.: 21% flat rate (since 2017 Tax Cuts and Jobs Act)	Income Tax: (a) primary activities: 50%; and (b) other activities: 34% Value-added tax: (a) general rate is 16%; and (b) 0% for sales of natural hydrocarbons made by joint ventures to PDVSA or any of its subsidiaries Other taxes: Surface Tax, Excise Tax, General Consumption Tax, Extraction Tax and Export Registration Tax Special contributions: (a) science and technology contribution (1% of gross profits); (b) anti-drugs trafficking contribution (1% of net profits); and (c) sports contribution (1% of net profits)
Export Taxes	Rates set between 0% and 8%	N/A	Special contribution for the Catatumbo region: a 1% tax specifically applicable to the extraction of hydrocarbons within Colombian territory This contribution is triggered by: (i) the first sale within Colombian territory, and (ii) the filing and acceptance of the shipping request for export This tax is temporary and will remain in effect only until December 31, 2025	VAT rate for exported goods is 0%. There are no other taxes on exports If the proceeds from the export of goods or services are not brought into the country within 180 days after the export takes place, a presumptive remittance tax of 5% applies to those resources	Exports require prior authorization by Ministry of Energy	0%	0%	No export taxes on crude oil or natural gas	0,1%

	ARGENTINA	BRAZIL	COLOMBIA	ECUADOR	MEXICO	PERU	URUGUAY	USA	VENEZUELA
Domestic Price Controls & Export Permits	No domestic price controls; export permits required	No domestic price controls; ANP monitors market pricing; export permits required (international trade agent permit and permit per export)	No domestic price controls; export registrations and permits required for oil commercialization. For natural gas, transportation and final client distribution as public utility fixed fees apply. Exports of natural gas are subject to interruption if natural local demand is not satisfied.	No domestic price controls; export permits required	No domestic price control implemented in the upstream sector; export permits required for oil and gas.	No domestic price controls Regular Custom proceedings shall be complied with	No domestic price controls Regular Custom proceedings shall be complied with	None No federal domestic price controls on oil or natural gas Exports require Department of Energy authorization, and additional permitting may be required depending on the location	Domestic price controls; exports are monopolized by the state; exceptionally, private companies can export if justified by international sanctions and permitted by the state
Environmental Impact Assessment	Required	Required	Required	Required	Required	Required	Required	Required	Required

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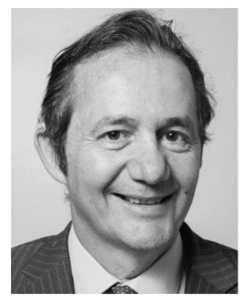

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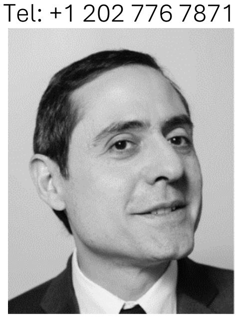

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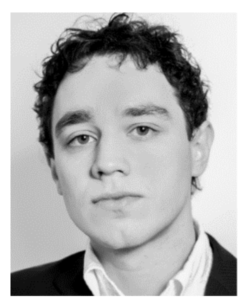

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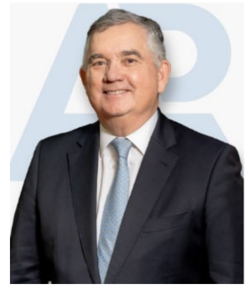

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