Global Energy Industry Review

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Our Global Energy Practice

Mayer Brown has advised major participants in the energy sector across the entire spectrum of their operations and has acted as counsel of choice with regard to significant transactions and litigation matters. Our Energy practice includes lawyers from the key disciplines of finance, corporate, securities, tax, environment, trade and energy regulation, and dispute resolution, as well as US and EU regulatory capabilities in Washington DC and Brussels.

Our lawyers have earned an enviable reputation in the energy industry. Our worldwide client base includes companies representing the full spectrum of the industry, as well as those that finance or invest in them. We have advised clients in the following energy sectors:

OIL AND GAS
- Exploration and Production
- Midstream
- Downstream
- Pipeline
- Liquefied Natural Gas (LNG)
- Petrochemicals

POWER
- Electric
- Natural Gas
- Transmission
- Coal
- Nuclear

RENEWABLE ENERGY
- Wind
- Solar
- Biomass
- Hydro
- Geothermal
- Waste-to-Energy

We draw on talent from our offices around the world, including the principal energy and energy finance centers of London, New York, Hong Kong, Houston and Singapore. These market centers have a tradition of hosting, servicing or financing energy firms, and we have a substantial presence in each of them.
We are pleased to provide our clients and friends with this composite of brief, yet insightful, articles on topics that we believe have captivated much of the energy industry’s attention through 2014. As we look with a watchful eye on the energy markets in 2015, we are optimistic that the world’s energy demands will continue to drive international growth.

Geopolitical and legal developments continue to drive the opportunities for energy investments in developing energy markets, such as Mexico, Romania and Nigeria. Each of these countries has undertaken significant reforms of their legal frameworks in order to support their overall goal of increasing foreign investment. In this respect, we address:

- Main features of Mexico’s new Hydrocarbons Law and Hydrocarbons Revenues Law passed in August 2014;
- Analysis of Mexico’s new Electric Law, passed in August 2014;
- Overview of upstream and midstream opportunities in Romania’s energy sector; and
- Recent and planned developments in Nigeria’s power industry and the challenges and opportunities ahead.

In the Review, we also focus on the increased role of private equity (PE) in the energy industry, particularly the upstream sector, and the factors that have been driving increased activity.

Next, we examine the EU State aid that was established in 2007 to increase the use of renewable energy and the recent scrutiny that has triggered several highly political investigations of State aid guidelines against Member States, including Germany, Sweden and the United Kingdom.

Finally, we focus on Brazil and the significant tax dispute between Brazil’s oil & gas industry and the Brazilian Revenue Service that developed as a result of taxation over outbound payments related to charter agreements for vessels.

We are hopeful that these articles can be of some value and that we have demonstrated our firm’s worldwide reach.

As always, we encourage you to visit the Energy News and Publications page on our web site for a complete list of our articles and energy-related updates.

If you have any questions or comments on any of this edition’s articles, please contact us.
Analysis of Mexico’s New Hydrocarbons Legal Regime

Dallas Parker  
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This legal update addresses the main features of the Hydrocarbons Law and the Hydrocarbons Revenues Law, which became effective on August 12, 2014.

The Hydrocarbons Law and the Hydrocarbons Revenues Law are part of a set of new laws to implement the constitutional energy reform that became effective on December 21, 2013.

Overview

Together, the Hydrocarbons Law and the Hydrocarbons Revenues Law establish a new legal framework for all hydrocarbon-related activities in Mexico, including the following:

- Surface and geophysical surveying, and exploration for, and extraction of, hydrocarbons;
- The treatment, refining, transportation, storage, marketing and sale of petroleum and petroleum products;
- The processing, compression, liquefaction, decompression and regasification, as well as the transportation, storage, distribution, marketing and retail sales, of natural gas; and
- Pipeline transportation and storage of petrochemicals.

For exploration and production (E&P) activities, the Hydrocarbons Law establishes two different regimes to be regulated by the National Hydrocarbons Commission (CNH): entitlements (called “asignaciones” in Spanish) granted to State Productive Enterprises (wholly owned state entities, including PEMEX) and E&P contracts entered into with private parties or State Productive Enterprises. For midstream and downstream activities, the law establishes a “permit” regime to be generally regulated by the Ministry of Energy (SENER) and the Energy Regulatory Commission, as further described in Section III below.

Within 180 calendar days of the enactment of the Hydrocarbons Law, the executive branch is to issue the regulations (reglamento) under the Hydrocarbons Law.

Upstream Sector

PEMEX ROUND ZERO

The transitional articles of the constitutional reform establish the so-called “Round Zero” process, during which PEMEX had the right to request E&P rights over areas that it currently has under production or that it is actively exploring. Any E&P rights granted to PEMEX under the Round Zero process would be under the entitlement regime.
One of the main objectives of the reform is that, after this initial round, PEMEX is to compete on an equal footing with other operators in obtaining additional contract areas.

On March 21, 2014, PEMEX submitted its Round Zero request to the SENER, requesting to retain the following:

- 100 percent of PEMEX’s producing areas;
- 83 percent of Mexico’s proven and probable reserves (2P reserves); and
- 31 percent of Mexico’s prospective resources.

On August 13, 2014, the SENER announced that PEMEX will be granted all of the requested producing and 2P reserves, and 21% of Mexico’s prospective resources (instead of the 31% requested).

ENTITLEMENTS

An entitlement is the administrative act by which the executive branch grants PEMEX or another State Productive Enterprise the right to explore and produce hydrocarbons in a determined area, subject to certain work program obligations, and for a particular duration.

SENER will be the entity responsible for granting or modifying entitlements to PEMEX or any other State Productive Enterprise for the performance of E&P activities.

The Hydrocarbons Law provides that entitlements shall be granted on an “exceptional” basis, which would seem to permit the granting of area entitlements to PEMEX even after the Round Zero process.

The Hydrocarbons Law provides that PEMEX (and other State Productive Enterprises, as applicable) may only assign or transfer an entitlement to another State Productive Enterprise and with prior consent from SENER. To meet its obligations under the entitlements, PEMEX may only enter into service contracts with private parties, which may only provide for cash payments to contractors.

It is through the entitlement regime that PEMEX has historically received areas for E&P activities in Mexico. However, the entitlements to be granted to PEMEX pursuant to the new legal framework will have stricter terms than the entitlements granted to PEMEX in the past, including work programs and mandatory relinquishment and termination events.

MIGRATION TO CONTRACTS

The Hydrocarbons Law provides that PEMEX may request the approval of SENER for the migration of entitlements into E&P contracts. In this migration process, the Ministry of Finance shall establish the fiscal terms and SENER will establish the technical terms relating to the migrated contracts.

With respect to entitlements migrated into contracts, PEMEX may enter into joint ventures with private parties. The Hydrocarbons Law also establishes that, when PEMEX decides to enter into associations with private parties with respect to a migrated E&P contract, a tender process will be conducted by the CNH to select PEMEX’s partner.
The Hydrocarbons Law further provides that SENER will seek PEMEX’s favorable opinion with regard to the experience and the technical, financial and operational qualifications that bidders would need to meet in order to participate in the bidding process.

In regard to E&P services contracts that have been granted by PEMEX before the enactment of the Hydrocarbons Law (namely, Integral Exploration and Production Contracts and Financed Public Work Contracts) and that are currently in effect, the following shall apply:

- The underlying contract area is expected to be awarded to PEMEX as part of the PEMEX Round Zero process;
- These contracts will not be modified by the enactment of the Hydrocarbons Law;
- The parties to those contracts may request SENER to migrate the underlying entitlement into an E&P contract under the new hydrocarbons regime;
- The migration will be conducted pursuant to the technical terms established by SENER (with PEMEX’s opinion) and the economic terms established by the Secretary of Finance, provided that they do not affect the balance of expected revenues for the nation;
- If the contract parties do not agree with the new contract terms, the original service contract will remain valid and unmodified;
- If the contract parties agree with the new terms, SENER shall approve the migration, and the CNH will sign a new E&P contract with PEMEX and its partner(s), which shall replace the original contract with PEMEX. In this case it shall not be necessary that CNH conduct a tender process to select such partner(s); in such case, the original service contract shall be terminated without any liability to the parties; and
- The investments made pursuant to the original service contract may be recognized as capital expenditures under the new E&P contract.

**E&P CONTRACTS**

Except for the migrations described in Part C above, E&P contracts shall only be granted through a competitive bidding process, organized and regulated by SENER, Secretary of Finance, and the CNH.

Under the constitutional reform and the Hydrocarbons Law:

- SENER is charged with selecting areas for public bidding and establishing the technical and financial qualifications for bidders;
- The CNH is charged with conducting the bidding process, evaluating bids and awarding contracts; and
- The Ministry of Finance is charged with establishing the economic and fiscal terms of the E&P contracts.

Pursuant to the Hydrocarbons Revenues Law, the variables to be evaluated for the award of E&P contracts will be economic in nature, with the prevailing principle of maximizing the nation’s revenues. The Ministry of Finance will establish the economic variables to be evaluated, which will be the percentage of the value of production or percentage of production to be received by the nation, the investment amounts committed by the contractor, or a combination of both.

The new contract models for E&P activities are: (i) licenses, (ii) production-sharing contracts, (iii) profit-sharing contracts and (iv) service contracts. The Hydrocarbons Revenues Law provides for the economic aspects relating to each of the contract models.

**License Contracts**

Pursuant to the Hydrocarbons Revenues Law, the license contracts shall provide for the following payments in favor of the nation:

- Signing bonus;
- Exploratory phase fees;
• Royalties; and
• A payment that consists of a percentage of the contract value of hydrocarbons produced.

The contractor may take and own the hydrocarbons in-kind at the wellhead. All of the above payments shall be paid in cash by the contractor. These payments are in addition to any taxes owed by the contractor pursuant to the Mexican Income Tax Law or other tax laws.

**Signing Bonus**

The signing bonus amount shall be established by the Ministry of Finance in the bid terms for each tender process. The signing bonus is to be paid to the newly established Mexico Oil Fund.

The signing bonus will be paid at the moment and under the terms established in the specific tender process. The signing bonus amount will be fixed and will be determined in the bid terms. It will not be a factor in awarding the contract. The signing bonus is not expected to represent a significant percentage of the resources to be received by the nation but rather a mechanism to guarantee the seriousness of the economic bids.

**Exploratory Phase Fees**

License contracts shall establish a monthly payment during the exploratory phase with respect to non-producing areas. The concept is similar to the delay rentals usually established under oil and gas leases in the United States. The exploratory phase monthly fees are as follows: (i) $1,150 Mexican pesos (having a current value in US dollars of approximately $87) per square kilometer during the first 60 months of the contract term and (ii) $2,750 Mexican pesos (having a current value in US dollars of approximately $207) per square kilometer starting from month 61 of the contract term. These amounts shall be adjusted annually for inflation on the basis of the Mexican National Consumer Price Index. The purpose of these payments is to provide an incentive to the contractor to move promptly to the production phase.

The exploratory phase fees are to be paid to the newly established Mexico Oil Fund.

**Royalties**

License contracts shall establish royalties in favor of the nation that shall vary depending on the type and market price of the particular hydrocarbon (crude oil, associated and non-associated natural gas or condensates) effectively produced. Royalties are payable in cash.

Royalty payments shall be determined based on the “contract value” of produced hydrocarbons, which is calculated by multiplying the volume of production by its “contract price.” The contract price for each type of hydrocarbon is its market price in US dollars, as adjusted pursuant to a mechanism to be established in each E&P contract. The mechanism will take into account the hydrocarbon’s quality, API gravity, marketing, and transportation and logistical costs, among other factors.

Crude oil royalties start at 7.5 percent when the contract price of crude oil is below US$48 per barrel and would increase as the contract price of crude oil increases. When the contract price of crude oil is equal to or greater than US$48 per barrel, the following formula would be applied:

\[
\text{Rate} = [(0.125 \times \text{crude oil contract price}) + 1.5] \%
\]

Per this formula, when the contract price of crude oil is US$100, a 14 percent royalty would be applicable.

Condensates royalties start at 5 percent when the contract price of condensates is below US$60 per barrel. When the condensates contract price is equal or greater than US$60 per barrel, the following formula should be applied:

\[
\text{Rate} = [(0.125 \times \text{condensates contract price}) – 2.5] \%
\]

Per this formula, when the contract price of condensates is US$100, a 10 percent royalty would be applicable.

As an economic incentive for non-associated natural gas development, a zero percent royalty
would apply when the contract price of non-associated natural gas is lower than or equal to US$5.00 per 1 million BTU. When the contract price of non-associated natural gas is higher than US$5.00 but lower than US$5.50 per 1 million BTU, royalties are calculated using the following formula:

\[
\text{Rate} = \frac{\text{Natural gas contract price} - 5}{60.5} \times 100
\]

When the contract price of non-associated natural gas is equal to or higher than US$5.50 per 1 million BTU, royalties are calculated using the following formula:

\[
\text{Rate} = \frac{\text{Natural gas contract price}}{100}
\]

The above economic incentives are not applicable to associated natural gas. Royalties for associated natural gas shall be calculated using the following formula:

\[
\text{Rate} = \frac{\text{Associated natural gas contract price}}{100}
\]

Payment that Consists of a Percentage of the Contract Value of Hydrocarbons

The license contracts shall provide for a payment to be established on a contract-by-contract basis by the Ministry of Finance, depending on the type of project, consisting of a percentage of the contract value of hydrocarbons produced. This percentage, as offered in the bid process, would be a contract award criterion.

As mentioned above, the “contract value” of produced hydrocarbons is calculated by multiplying the volume of production measured by its “contract price.” The contract price for each type of hydrocarbon refers to its market price in US dollars, as adjusted pursuant to a mechanism to be established in each E&P contract. The mechanism will take into account the hydrocarbon’s quality, API gravity, marketing, and transportation and logistical costs, among other factors.

In addition, the contractor may be subject to minimum investments or work programs committed during the bidding process.

Production-Sharing Contracts

Pursuant to the Hydrocarbons Revenues Law, production-sharing contracts shall establish the following payments in favor of the nation: (i) exploratory phase fees (same as those applicable to licenses), (ii) royalties (same as those applicable to licenses) and (iii) a payment that consists of a percentage of operating profits. The exploratory phase fees are paid in cash, and the royalties and share of operating profits are paid in-kind. These payments are in addition to any taxes owed by the contractor pursuant to the Mexican Income Tax Law or other tax laws.

Depending on the fiscal terms established in each contract by the Ministry of Finance, the contractor receives in kind either (i) the cost recovery plus the balance of the operating profits, or (ii) all production net of the production paid to the nation.

The operating profits shall generally be calculated by subtracting the following amounts from the contract value of the hydrocarbons produced: (i) the royalty amount paid by the contractor and (ii) the costs incurred by the contractor. Article 19 of the Hydrocarbons Revenues Law lists the costs that may not be deducted for purposes of calculating the operating profits.

Under the production-sharing contracts, the contractor retains in-kind production with a value equal to the recoverable costs and its share of operating profits. The production equivalent in value to the state’s share of profits is to be delivered to the marketing firm retained by the CNH.

These contracts will include an adjustment mechanism for the profit split rates so that the Mexican state “may capture the extraordinary profitability” from production.
**Profit-Sharing Contracts**

Pursuant to the Hydrocarbons Revenues Law, profit-sharing contracts shall establish the following payments in favor of the nation: (i) exploratory phase fees (same as those applicable to licenses), (ii) royalties (same as those applicable to licenses) and (iii) a payment that consists of a percentage of operating profits. These payments are in addition to any taxes owed by the contractor pursuant to the Mexican Income Tax Law or other tax laws.

As consideration, the contractor has the right to (i) recover costs as established by such law and (ii) receive a payment that will consist of the balance of the operating profits after paying the specified percentage of operating profits to the nation.

The contractor will deliver all of the production to the marketing firm retained by the CNH, which shall pay the sale proceeds to the Mexico Oil Fund. The Mexico Oil Fund shall retain the amounts belonging to the nation and shall pay the contractor the cost recovery and its share of profits in cash on a monthly basis.

These contracts will include an adjustment mechanism for the profit split rates so that the Mexican state “may capture the extraordinary profitability” from production.

**Service Contracts**

Under service contracts, contractors will deliver all production to the state, and fee payments shall only be made in cash as established in each contract. Exploratory phase fees and royalties will not apply to service contracts. Payment to the contractor shall be made by the Mexican Oil Fund with the proceeds from the sale of the production derived from the respective service contract.

**PEMEX PARTICIPATION IN E&P CONTRACTS**

The Hydrocarbons Law establishes that PEMEX may participate in tender processes for E&P contracts (after the Round Zero process) and may freely enter into joint ventures with private parties to participate in those tender processes. Unlike in entitlements migrated to E&P contracts, when PEMEX is granted an E&P contract in a competitive tender process, PEMEX, like any other private party, would be able to directly (without the need for bid process) assign some or all of its rights and obligations under such E&P contract to another party under the terms established by the law.

Pursuant to the Hydrocarbons Law, SENER may establish, within the bidding terms of E&P contracts, that PEMEX’s participation in a contract is required in the following cases:

- Where PEMEX has an entitlement that coexists, at a different depth, with an offered contract area;
- Where there are opportunities to foster the transfer of knowledge and technology for the development of the capabilities of PEMEX or another State Productive Enterprise (up to a maximum 30 percent required participation); and
- For projects that are to be supported by a specialized financial vehicle from the Mexican state, such as the Mexico Oil Fund (up to a maximum 30 percent required participation).

SENER shall establish, within the bidding terms of E&P Contracts, that PEMEX is to have a required participation:

- Where there is a possibility of discovering an international transboundary deposit (with a minimum required participation of 20 percent).

**NATIONAL CONTENT**

The minimum average local content requirement for E&P activities will be 25% by 2015 and will be gradually increased to 35% by 2025. Deep water and ultra-deep water activities may have a lower requirement, as determined by the Ministry of Economy.
The specific percentage of national content required shall be established in the bidding terms of E&P contracts. The Ministry of Economy shall establish the measurement methodology for national content in entitlements and E&P contracts, taking into consideration the following factors:

- the goods and services to be contracted, considering their place of origin,
- the qualified local work,
- the investment in local and regional infrastructure, and
- the transfer of technology.

The entitlements and E&P contracts will include specific penalties for the failure to comply with the national content requirements.

**INFORMATION FROM E&P ACTIVITIES**

The Hydrocarbons Law establishes that Mexico owns all geological, geophysical, petro-physical and petrochemical information, as well as the information obtained from geological surveys and E&P activities that are carried out by PEMEX, any Productive State Enterprise or private parties. The CNH will retain, administer and use this information and publish it through the National Center of Information.

PEMEX, any other State Productive Enterprise and all other persons are prohibited from publishing, delivering or obtaining any of the information mentioned in the preceding paragraph by means other than those contemplated in the law or without the CNH’s consent.

In addition, PEMEX, its affiliates and the Mexican Petroleum Institute are required to transfer without cost to the CNH all of said information, as well as information obtained from surveys and surface exploration, and information on reserves, to the extent it was obtained before the effective date of the Hydrocarbons Law (August 12, 2014). This transfer must be made within a period of time that shall not exceed two years and shall be conducted pursuant to regulations to be issued by the CNH.

The CNH shall have unrestricted access to PEMEX’s and the National Petroleum Institute’s facilities, information and assets.

Contractors and State Productive Enterprises are required to deliver to the CNH information obtained in their surveys and surface exploration. The CNH shall keep this information confidential. The CNH may contract with third parties to conduct surveys and subsurface (seismic) exploration.

**Midstream and Downstream Sectors**

All midstream and downstream hydrocarbon activities may be carried out under permits to be issued by SENER or the Energy Regulatory Commission to any qualified person.

**PERMITS**

The following activities will require a permit from SENER:

- Treatment and refining of petroleum;
- Processing of natural gas; and
- Import and export of crude oil, natural gas and petroleum products.

The following activities will require a permit from the Energy Regulatory Commission:

- Transportation, storage, distribution, compression, liquefaction, decompression, regasification, marketing and retail sale of crude oil, natural gas, petroleum products and petrochemicals; and
- Integrated pipeline transportation and storage systems.

The Hydrocarbons Law includes provisions relating to the permit application process, and suspension, revocation and other general terms relating to permits.
Any person who currently engages in treatment, refining or processing activities, and who does not have a permit granted by SENER will need to obtain a permit from SENER under the new law no later than June 30, 2015, to be able to continue such activities.

Any person who currently engages in transportation, storage, distribution, compression, liquefaction, decompression, regasification, marketing and retail sale activities, and who does not have a permit granted by the Energy Regulatory Commission will need to obtain a permit from the Energy Regulatory Commission under the new law no later than December 31, 2015, to be able to continue such activities.

**NATIONAL CENTER OF NATURAL GAS CONTROL**

The National Center of Natural Gas Control (CENAGAS) must be established by the executive no later than twelve months after the enactment of the Hydrocarbons Law. CENAGAS will have, at the outset, a dual function: (i) it will acquire from PEMEX, and own and operate, all of PEMEX’s gas transmission pipeline and storage facilities and (ii) it will be the independent administrator of the “National System for the Integrated Transportation and Storage of Natural Gas.”

The National System for the Integrated Transportation and Storage of Natural Gas will be comprised of (i) the natural gas transmission pipeline and storage facilities and (ii) compression, liquefaction, decompression, regasification and other related infrastructure owned by CENAGAS or owned by private parties that desire to interconnect to them.

The Hydrocarbons Law contemplates the existence of interconnected transmission and storage systems which shall have their own separate and independent administrators in addition to, and separate from, the National System for the Integrated Transportation and Storage of Natural Gas.

CENAGAS will deliver to SENER, with the technical opinion of the Energy Regulatory Commission, a five-year plan relating to the expansion of the National System for the Integrated Transportation and Storage of Natural Gas. CENAGAS will carry out the tender processes for projects that are considered “strategic” for the nation based on criteria established in the law.

For non-strategic projects, State Productive Enterprises and private parties may carry out infrastructure projects under their sole risk and responsibility. State Productive Enterprises, such as the Federal Electricity Commission (CFE), are required to conduct tender processes to select a third party to develop their infrastructure projects, in which such State Productive Enterprises may be able to reserve for themselves the capacity that is required for their operations.

**OPEN ACCESS AND COMPETITION FOR MIDSTREAM ACTIVITIES**

The Hydrocarbons Law establishes that all permit holders providing transportation, distribution or storage services shall provide open and non-discriminatory access to their facilities, subject to available capacity and pursuant to rules to be issued by the Energy Regulatory Commission.

The Energy Regulatory Commission, with the opinion of the Federal Economic Competition Commission, may establish regulations to promote a competitive energy sector that may include the strict legal separation among activities or the administrative, operational or accounting separation of certain activities.

**RETAIL SALES**

Starting on January 1, 2017, or any time before such date if market conditions allow it, import permits for gasoline and diesel fuel may be granted by the Energy Regulatory Commission.

Starting on January 1, 2016, permits for the retail sale of gasoline and diesel fuel may be granted to
Regarding gasoline and diesel retail prices, the following shall apply:

- Through the end of 2014, prices will be regulated pursuant to the current regulations;
- Starting January 1, 2015, until December 31, 2017, gasoline and diesel prices shall be established by the Executive Branch by decree, taking into account transportation cost differences between regions and other factors; and
- Starting January 1, 2018, retail prices for gasoline and diesel will be freely determined by market conditions.

**Anticorruption, Transparency and Penalties**

Pursuant to the Hydrocarbons Law, SENER, the Ministry of Finance and the CNH shall publish information on a monthly basis relating to contract areas offered, E&P contracts and entitlements granted, permits approved, oil revenues received by the nation and payments made to contractors, among other information.

The Hydrocarbons Law also contains a specific chapter for anticorruption and transparency, providing that any person (private party or public official) who conducts “corrupt acts” shall be sanctioned. Corrupt acts shall also constitute termination events of entitlements, E&P contracts and permits.

The Hydrocarbons Law includes a chapter establishing specific fines for violations to the law applicable to State Productive Enterprises and private parties participating in the Mexican hydrocarbons sector. Depending on the subject matter, these fines may be imposed by SENER, the Ministry of Finance, the CNH, the Energy Regulatory Commission or the National Agency of Industrial Security and Environmental Protection.

**Land Issues**

The Hydrocarbons Law establishes that hydrocarbon activities are public-interest activities which shall prevail over any other activity that requires surface or subsoil use. Accordingly, the Hydrocarbons Law authorizes the establishment of legal easements or the necessary surface occupation or use of privately owned land in connection with the performance of hydrocarbon activities.

The consideration for the purchase, use or occupation of land, goods or rights that are necessary for conducting E&P activities shall be negotiated directly between property owners and the contractors or State Productive Enterprise, as applicable. The Hydrocarbons Law establishes a detailed process by which such negotiations shall be conducted.

For E&P projects that reach commercial production, property owners may be paid a percentage of the revenues that are related to the contractor or State Productive Enterprise for the particular project, deducting any amounts owed to the Mexican Oil Fund. This percentage shall range between 0.5 percent and 3 percent for non-associated natural gas and between 0.5 percent and 2 percent for all other hydrocarbons.

The Institute of Administration and Appraisals of National Assets (Instituto de Administración y Avalúos de Bienes Nacionales), a state entity in charge of administering national assets, shall establish and maintain data regarding the average prices for the use, occupation or purchase of land, which data shall serve as a starting point for subsequent negotiations.

Any agreement reached by the parties shall be submitted by the contractor or State Productive Enterprise to the competent district judge of civil matters or unitary agrarian judge for examination and, if applicable, validation.

If the parties do not reach an agreement within 180 days, the State Productive Enterprise holding an entitlement or the contractor holding an E&P
contract, as applicable, may (i) request a district judge of civil matters or unitary agrarian judge to grant a “legal hydrocarbon easement” or (ii) request the Institute of Administration and Appraisals of National Assets to conduct a mediation pursuant to a specific process established in the same law. If the parties do not reach an agreement after such mediation, SENER shall then propose to the executive branch the establishment of a legal hydrocarbon easement.

The legal hydrocarbon easement established by the Hydrocarbons Law is a new legal concept under Mexican Law that can be established judicially (by a competent judge) or administratively (by the executive branch).

The legal hydrocarbon easement comprises the following rights:

• Transit right of persons;
• Transportation, handling and storage of all kinds of construction materials, vehicles, equipment and goods; and
• Construction, installation and maintenance of infrastructure or carrying out works necessary for the development or monitoring of the activities contemplated in an entitlement or E&P contract.

The legal hydrocarbon easement shall not exceed the duration of the respective E&P contract or entitlement. The Hydrocarbons Law provides a mechanism to establish the consideration for each legal hydrocarbon easement.

Social Issues
In regard to social issues, the Hydrocarbons Law establishes that, prior to the granting of any entitlement or bid publication for an E&P contract, SENER, in coordination with the Ministry of Interior (Secretaría de Gobernación) and other competent authorities, shall conduct a social impact study in regard to the relevant area. The results of such study shall be made available to the entitlement holder or bid participants. SENER shall inform entitlement holders and bid participants about the presence of vulnerable social groups in the corresponding areas, with the stated purpose of protecting the rights of those groups. In addition, SENER, in coordination with the Ministry of Interior, shall carry out a consultation process and any other necessary activity to protect the rights of vulnerable social groups, with the objective of reaching agreements with social groups or, if applicable, their consent under applicable law.

SENER may establish, in entitlements or in bid terms, the amounts and other obligations that an entitlement holder or contractor shall contribute for the sustainable development of local communities in the areas of health, education and labor, among others.

In addition, E&P contractors, State Productive Enterprises and persons interested in obtaining a permit for midstream and downstream projects shall deliver to SENER a social impact evaluation regarding the impact of their proposed activities, as well as the corresponding social plans and mitigation measures.

Environmental Issues
The Hydrocarbons Law does not regulate environmental matters, which will be addressed by upcoming environmental laws and regulations. The Hydrocarbons Law generally provides that all parties engaged in hydrocarbon activities will prevent and repair environmental damages caused by their activities, and, to the extent declared responsible of violations by competent authorities, they will bear the repair costs pursuant to applicable laws.

The National Agency for Industrial Safety and Environmental Protection, to be created under accompanying legislation, will issue the rules regarding safety and environmental matters.

Selected Tax Provisions
The Hydrocarbons Revenues Law establishes the following selected tax provisions applicable to hydrocarbon activities:
A “permanent establishment” for income tax purposes is created when a non-resident company carries out oil and gas activities in Mexico for more than 30 calendar days in any 12-month period;

Salary payments to non-resident employees paid by a non-resident employer without a permanent establishment in Mexico for services rendered in Mexico related to oil and gas activities for more than 30 days in any 12-month period are subject to individual income tax payments;

Companies and consortiums are permitted to hold more than one E&P contract (no ring-fencing);

New tax applicable to E&P activities consisting of: (i) 1,500 Mexican pesos (having a current value in US dollars of approximately $114) per square kilometer of contract area during the exploratory phase and (ii) 6,000 Mexican pesos (having a current value in US dollars of approximately $455) per square kilometer of contract area during the production phase. The tax proceeds will be distributed to the new “Fund for Hydrocarbons Producing States and Municipalities” with the primary objective of repairing any harm caused by E&P activities to the environment and infrastructure of the states or municipalities.

It is important to note that, under the 2014 tax reform in Mexico, holding companies are generally no longer permitted to file consolidated tax returns.

In addition to the tax provisions contained in the Hydrocarbons Revenues Law, persons carrying out hydrocarbon activities will be subject to the ordinary Mexican tax laws. ✦
Analysis of Mexico’s New Electric Industry Law

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A new law (the “Electricity Law”) opening the electric industry to private sector participation in generation, transmission, distribution and power marketing activities became effective on August 12, 2014. The Electricity Law is part of a set of new laws to implement the constitutional energy reform that became effective on December 21, 2013.

This legal update addresses the main features of the new Electricity Law.

Background

The Mexican electric industry was governed by a restrictive legal framework that limited private sector participation and reserved most of the market to the state-owned Federal Electricity Commission (Comisión Federal de Electricidad or the CFE). Since 1992, private sector investment has been restricted to certain electric generation projects. Private companies could not take part in the transmission and distribution sectors, and there was no power trading market.

The CFE was vertically integrated—combining the operation of the national grid, its control of the wholesale generation market, a monopoly over transmission and distribution, and the supply to almost all Mexican customers. This structure caused inherent difficulties in adequately and efficiently supplying the electric energy demand in Mexico due, in part, to (i) CFE budgetary constraints, (ii) opaque rules for interconnection to the national grid and (iii) severe congestion, limiting transmission services. Because CFE’s budget was in effect controlled by the national treasury, the CFE long ago ceased to have the financial resources to properly maintain and expand the country’s electric infrastructure.

Electric tariffs in Mexico were set by the Department of Finance (Secretaría de Hacienda) and not by the Energy Regulatory Commission (Comisión Reguladora de Energía or the CRE), the industry regulator, resulting in a tariff regime more responsive to political considerations than economic realities. While the industrial and commercial sectors generally do not receive government subsidies, agricultural and residential customers have received large subsidies. Despite these subsidies, residential consumers in Mexico pay, on average, higher tariffs than the same consumers in the United States.
The New Electricity Law

The Electricity Law provides separately for generation, transmission, distribution and power marketing activities.

From the regulatory side, three agencies will have primary responsibility for the sector. The Department of Energy (Secretaría de Energía or the SENER) will have the policy function; the CRE will have the regulatory function; and the CENACE, a new decentralized agency, will manage the power grid and the wholesale electric market.

The generation and wholesale of electricity will take place under a regime of free enterprise and open competition. The CFE will be just one competitor in the new generation market.

While transmission and distribution facilities will remain under state ownership, the private sector will be able to participate in the construction, operation and maintenance of such facilities.

The operation of the National Electricity System, including the new wholesale electric market, will be run by the CENACE. This agency will also regulate open and non-discriminatory access to the transmission and distribution infrastructure.

The participants in the new wholesale electric market shall be the generators, power marketing companies and large end users (or “qualified customers”). The power marketing companies may sell power to end users (which may be qualified customers or regulated customers).

GENERATION SECTOR

- A permit from the CRE is required for the construction, ownership and operation by any qualified person of power plants with a generation capacity greater than or equal to 0.5 MW.
- The permits shall also include the right to build, own and operate private interconnection lines to deliver power output to the grid.
- Generation companies whose output cannot meet their contractual customers’ energy demand will have to purchase energy in order to meet such demand (i) in the wholesale electric market or (ii) through power purchase and sale agreements (PPAs) with other generators or with power marketing companies.
- Generation companies can, in turn, sell their electricity (i) in the wholesale electric market or (ii) by entering into PPAs with a power marketing company, with qualified customers or with other generators.
- Participation by generation companies in power marketing activities through affiliates is not prohibited.
- Generation companies that produce energy through renewable sources or clean technologies shall be eligible to receive tradable clean energy certificates.
POWER MARKETING (SUPPLIERS)

• To the extent a power marketing company sells power, it is called a supplier. Any qualified person may obtain a permit from the CRE to supply power to qualified or regulated customers.

• There are three different types of suppliers: (i) basic service suppliers, (ii) qualified service suppliers and (iii) last resource suppliers.

• The basic supply is the supply of electric power under a regulated tariff regime. Regulated customers are residential consumers and small businesses.

• The qualified supply is provided pursuant to freely negotiated PPAs with large end users.

• The last resource supply is provided to qualified customers in emergency cases under maximum rates.

• Power marketing companies may purchase electric energy (i) in the wholesale electric market or (ii) through PPAs with generators or other power marketing companies. Purchase of power by power marketing companies for resale to regulated customers must be carried out through competitive bidding processes.

• Suppliers (and qualified customers participating directly in the wholesale electric market) will be required to acquire clean energy certificates.

QUALIFIED CUSTOMERS

• The designation as a qualified customer is attached by registration with the CRE. The applicant shall demonstrate that its existing demand exceeds certain thresholds (initially 3MW, with such threshold being reduced to 1MW by the third anniversary of the effective date of the Electricity Law).

• A qualified customer may purchase energy (i) in the wholesale electric market or (ii) under a PPA with a generation company or a power marketing company.

• There will be obligatory requirements for the acquisition of clean energy certificates by qualified customers that purchase energy directly in the wholesale electricity market.

WHOLESALE ELECTRIC MARKET

• It is a spot market operated by the CENACE where generators, suppliers and qualified customers (acting directly and not through a power marketing company) are gathered for selling and buying electricity at real-time system marginal costs.

• Generation companies must operate their units in accordance with the dispatch orders of the CENACE and coordinate their maintenance operations with the CENACE.

• The CENACE will dispatch the system’s power plants based on a merit order of ascending operating costs (regardless of their contracted capacity under PPAs), under which the lowest operating cost power plant satisfies system energy demand before the next lowest operating cost plant is dispatched.

• The CENACE can form partnerships with private parties in order to provide auxiliary services for spot market operations.

TRANSMISSION AND DISTRIBUTION

• The CFE through its affiliates (or other state-owned companies) will own the transmission and distribution lines and will provide the service of transmission and distribution of electricity. However, such entities will not directly buy or sell the electricity that flows through their lines.

• Tariffs for transmission and distribution services will be regulated by the CRE.

• The SENER or the CFE’s affiliates may form partnerships or reach agreements (through public bidding processes) with private entities in order to carry out the financing, installation, maintenance, management, operation and expansion of transmission and distribution infrastructure.
• Transmission and distribution grids will be under a “not unduly discriminatory open access” regime managed by the CENACE.

CFE
• The new CFE will operate through separate affiliated companies to take part in every sector of the electricity industry.
• The new CFE will have to compete on an equal footing with private parties in the generation and marketing of electricity, but will remain the exclusive provider of transmission and distribution services.

CLEAN ENERGY CERTIFICATES
• The SENER will establish the criteria for issuing clean energy certificates to generators, which will relate to energy generated by clean technologies (as defined in the Electricity Law).
• The SENER will also regulate the obligation of the suppliers and qualified consumers that participate in the spot market to acquire clean energy certificates, in proportion to energy purchased or consumed.
• The clean energy certificates shall be negotiable.

USE OF LAND
• The transmission and distribution of electricity have a special priority over any other activities that involve the use of the surface and subsurface of lands lying within the limits of the respective projects, including hydrocarbon-related activities. The affected lands are subject to legal easements for the installation of transmission and distribution networks.
• The Electricity Law contemplates the right of occupation and use of land owned by third parties for the location, construction and operation of site-specific generation projects (ie., hydroelectric plants) and transmission and distribution facilities. The consideration for the purchase, use or occupation of land, goods or rights that are necessary for conducting these activities shall initially be negotiated directly between the interested parties. If they do not reach agreement, the industry participant may request that (i) a district judge grant a legal easement or (ii) the Ministry of Agricultural, Territorial and Urban Development conduct a mediation. Lack of agreement after the mediation may also result in the imposition of a legal easement.

NATIONAL CONTENT
The SENER will establish a minimum national content in the new projects related to the financing, construction, maintenance and operation of transmission and distribution facilities. This requirement will be subject to availability in terms of comparable quality, cost and time or performance.

Conclusion
The new Electricity Law establishes a legal framework for electricity-related activities in Mexico, and has structurally changed the national electric industry.

Its fundamental principles are:
• The generation and wholesale of electricity will take place under a regime of free enterprise and open competition.
• The CFE will no longer have a regulatory function and will not manage the electric power system.
• Transmission and distribution networks will be managed by an independent agency under an open access regime and regulated transmission and distribution tariffs.
• Large end users of power will be free to choose their suppliers and the terms and conditions of power supply.
• The new law provides for mechanisms to encourage the use of clean energy sources.
• The new law also provides for a mechanism to solve disputes concerning the required use of lands owned by third parties.

Much remains to be determined by regulations to be proposed and implemented in regard to this new law, but today there is a detailed picture of Mexico’s future electric power sector. ✦
The Ukrainian crisis has heightened the volatile environment for investments in Eastern Europe. However, it has also had the effect of concentrating the region’s focus on its long-term prospects regarding energy sufficiency. Romania, with its direct access to the Black Sea, has an opportunity to play an important energy-related role in the region. A member of both NATO and the European Union, Romania has a long history in the energy sector and has produced crude oil since 1857. In fact, numerous energy projects in Romania have been supported and financed by the European Union. The country benefits from a balanced energy mix and has one of the highest levels of energy security in Europe, with hydrocarbon production and potential both onshore and offshore. Romania enjoys an important strategic position with regards to the developing European Cross-Border Interconnectors system, forming a geographical bridge from the Caucasus region and Turkey to Central and Western Europe. However, Romania’s existing conventional onshore production is suffering from a relatively high depletion rate, which is accelerating. This rate of depletion means that its existing reservoirs, for the most part, are estimated to be exhausted by 2020. To address this critical issue, the Romanian government is planning to offer bids for new exploration blocks as early as the fall of 2014. There is also a need to improve the country’s existing domestic hydrocarbon oil and gas transportation networks, in addition to the development of the European interconnectors system. These developments offer a series of opportunities for potential investors in the energy sector in Romania.

Overview of the Upstream and Midstream Sectors in Romania

Below are some big-picture data points regarding the current state of Romania’s oil and natural gas industry:

- Romania’s annual crude oil production has averaged approximately 4 to 4.5 million metric tons in recent years, while its crude production volumes have steadily declined since 1977.
- Annual domestic natural gas production has averaged approximately 10-11 billion cubic meters per year, but natural gas production

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has generally decreased since 1986, although the rate of decline in annual natural gas production has stabilized during the past two years. This stabilization is largely a result of technological improvements being introduced and not because of new discoveries².

- Romania’s current production comes from approximately 400 operational reservoirs held almost exclusively by two companies:
  - OMV Petrom S.A., the largest oil and natural gas producer in Eastern Europe(239)³;
  - Romgaz SA, the state-controlled and largest producer and supplier of natural gas in Romania (more than 150)⁴.

- Substantially all of the crude oil currently produced from Romanian properties is produced by OMV Petrom. The company holds concessions in 239 blocks, which are currently producing or in the process of being developed. Approximately 20 percent of Romania’s total crude oil production is extracted from reservoirs located in the Black Sea, which are operated by OMV Petrom. The company’s predecessor was privatized by the Romanian government in 2004, and that company was then sold to OMV, the Austrian integrated energy company⁵.

- Romgaz and OMV Petrom each separately account for approximately 49 percent of Romania’s natural gas production⁶. Romgaz holds 132 blocks⁷, most of them in Transylvania and Northern Moldavia.

- Most producing reservoirs are small, having yearly production below 40,000 tons (280,000 Bbl) of crude oil, and 4 million cubic meters (141,26 Mcf) of natural gas. Approximately 20 percent of the total production is from mature reservoirs that are expected to be exhausted during the next 10 years. The recovery rate for oil produced is approximately 25 percent.

- There are 59 existing oil exploration, development and production licenses in various stages of performance in effect; exploration periods under many of these licenses have been extended due to difficulties encountered during drilling or due to needs for further testing.

- Participants in the upstream sector in Romania include super-majors, such as ExxonMobil (offshore in the Black Sea), Chevron (onshore shale gas plays), Lukoil and Gazprom, regional companies such as OMV, MOL, Petrom and Romgaz, independent international companies and medium and small companies. Most of the newcomers are still in the exploration phase.

- One refinery affiliated with OMV Petrom produces refined hydrocarbons in Romania. Its operational refining capacity currently totals approximately 4.5 million tons per year,⁹ but its output could be much greater considering that the national oil and natural gas transmission systems have not been utilized at their maximum capacities.

### Upstream Business Opportunities

A new bid round for new blocks is expected to be launched very soon. There is a possibility that OMV Petrom and Romgaz could partner with experienced operators having special technological know-how (such as deep-zone drilling) or perhaps farm out or otherwise transfer all or a portion of their rights to blocks in favor of a third party.

Romania has been, for the most part, self-sufficient in meeting its energy needs during modern times, and so the Romanian government has not actively sought major outside investment in this sector. However, it now appears that the government would be more supportive of energy sector investment by Western companies.
Currently, the partnering of existing licenses by way of joint operating agreements or take-over (farm-in) of existing licenses can be regarded as available business opportunities for exploration and production companies in the following areas:

i. Increasing the recovery rate from mature reservoirs;

ii. Exploring oil fields for depths exceeding 4000 meters;

iii. Investigating unconventional resources, namely shale gas;

iv. Drilling and hydraulic fracturing operations for unconventional resources, due to the fact that there are currently few specialized companies operating in Romania.

For the type of projects described in (i) and (ii) above, currently, the only potential business opportunities lead to the two majors on the market (Romgaz and OMV-Petrom) because they “control” most of the conventional reservoirs. Be it due to high financial costs and/or a lack of advanced technologies, these two companies do not insist on higher recovery rates or deep drilling on a larger scale. As a result, a potential third-party investor would either have to wait for relevant blocks to be abandoned by Romgaz or OMV-Petrom (whenever that would happen) or enter joint operating agreements with them. With regard to service companies, their opportunities would lie with the operators and the participation in the procurement process for the awarding of contracts.

Another potential opportunity lies in the expected 11th bid round for exploration blocks. The regulator, the National Agency for Mineral Resources (NAMR), should be launching the 11th bid round for 28 new licenses for on-shore blocks and 8 offshore blocks in the Black Sea. NAMR states that it intends to have the bid launched by 2014.

**Midstream Business Opportunities**

There are four projects that are currently prioritized by Transgaz SA (the Romanian state-owned Transmission System Operator “TSO”):

i. First priority would be to develop access to future major European gas infrastructures (e.g. TAP) or to sources from Central Europe. The total estimated cost is approximately 550 million euro—Required investments: New pipeline sections (approximately 520 km) and three compressor stations;

ii. Developing reverse flow capacities on existing infrastructures-interconnectors between (a) Romania-Hungary—Required investments: New pipeline (approximately 170 km) and two compressor stations; estimated cost: 190 million euro; deadline is 2016. (b) Romania-Bulgaria—Required investments: New pipeline (approximately 80 km) and one compressor station; estimated cost: 90 million euros; deadline is 2016.

iii. New pipeline project for connecting the Black Sea shore with the transmission corridor, including interconnections; Required investments: New pipeline section with a total length of 250 km; estimated investment cost: 255 million euros; estimated completion date is 2019–2020.

iv. Additional developments for an Increased Transmission Capacity connecting Black Sea offshore with National and Regional Markets. This will be a second route through Central Romania and a new interconnection with Hungary. This includes the rehabilitation of existing pipeline sections, the building some additional new pipeline sections and two compressor stations, with an estimated investment cost of 500 million euros.

It should be noted that financing for all of these projects must be structured.
Storage

For many years the Romanian government has declared its intention to promote the storage of natural gas, which should have been performed in depleted reservoirs of Romgaz. After some failed discussions with the Russian company Gazprom on the development of such storage projects, no notable progress was made in this regard. However, this is still considered a top priority.

As stated earlier, given the volatile geopolitical context in the region, energy security has moved to the top of the political and business agenda for European and local governments. This means that local Romanian stakeholders can prove to be more flexible toward new investors.

General Information About Romania

Romania has a uniquely advantageous strategic position at the crossroads of Europe, the Middle East and Eurasia:

- Active member of NATO and the EU, with a strong traditional pro-Western orientation
- Generally stable and democratic institutional framework
- One of the lowest corporate income taxes in Europe at 16 percent
- One of the lowest hydrocarbon royalty systems in Europe (between 3 and 13.5 percent)
- A lasting history in the oil and gas industry

Endnotes

1 Data from the Romanian National Agency for Mineral Resources – available here: http://www.namr.ro/petroleum-law/general-presentation-oil/
2 Ibidem
7 Info available in the second attachment of the following document: http://www.cdep.ro/interpel/2014/2r3359A.pdf
9 http://business-review.eu/featured/romania-prepares-for-new-petroleum-licensing-round-66438
Power Sector Privatisation in Nigeria: Opportunities and Challenges

Misi Oni

In the recently concluded Africa Summit in Washington, President Obama announced a US$14 billion commitment for investment in Africa by US companies.

This comes only a year after he announced “Power Africa”, a US government initiative to add over 30,000 MW of more efficient electricity generation capacity in six focus African countries, including Nigeria. During the Summit, the World Bank also announced a commitment of US$5 billion of support for “Power Africa”. This is timely. Power has been at the top of Nigeria’s agenda for a while, as it attempts to “switch the lights on” to create a more investor-friendly environment and increase internal productivity and growth.

This article looks at recent and planned developments in the Nigerian power industry, and the challenges and opportunities in the country in this vital sector.

Nigeria’s population of over 160 million is the largest in Africa. Its GDP growth rate is approximately 7 per cent and it has the highest levels of foreign direct investment in Africa—US$20 billion over the last three years. Therefore, it came as no surprise when during a recent GDP rebasing, Nigeria replaced South Africa as the largest economy in Africa.

The government of Nigeria has high aspirations for the country to be among the world’s top 20 economies by 2020 and in this regard, it has set up an Economic Transformation Agenda. This includes an ambitious target to generate 40,000 MW of electricity by that year, an enormous challenge, considering current power generation is only 4,000 MW.

One step towards this target was made with the decision to privatise the power sector. Nigeria’s President Goodluck Jonathan announced in 2010 that the government-owned Power Holding Company of Nigeria (PHCN), which had responsibility for the generation, transmission and distribution of electricity, would be sold to the private sector to increase efficiency and profitability.

The first phase of the privatisation was concluded in November 2013. This was a landmark US$2.5 billion transaction that saw PHCN unbundled into six generation companies (Gencos)—(four for thermal power and two for hydro)—and 11 distribution companies (Discos), and sold to new private owners.

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The transaction has been regarded as landmark for many reasons, not least because it is one of the world’s largest privatisations, and also because 70 per cent of the transaction was debt financed solely by local banks, a first of its kind.

Other interesting features of the transaction were that the government sold 100 per cent of its equity stake in some of the successor companies and the African Development Bank supported the process with the provision of a partial risk guarantee of up to US$180 million to guarantee the obligations of the Nigerian Bulk Electricity Trading (NBET) under its power purchase agreements with selected independent power projects.

Local debt financing available for the first phase of the privatisation was relatively expensive. It was expected at the time that this debt would be refinanced within 1½ to two years as internal governance and restructuring processes were adopted in the successor companies. However, due to increased appetite from international banks, it now appears that such refinancing might take place as early as 2015. Whether this refinancing from international markets will be across the board remains to be seen.

The Gencos have now been in operation for about eight months, with varying degrees of success. One of the more successful Gencos, Transcorp Ughelli Power, has already increased generating capacity from 160 MW to 453 MW within the first six months of operation due to close proximity to gas pipelines. According to Transcorp CEO Deoye Fadeyibi, the company is set to reach 750 MW by the end of the year. However, not all Gencos have been as successful in increasing capacity or reducing losses. The first refinancings are likely to be for more successful Gencos.

The second phase of privatisation, which is currently underway, relates to the sale of 10 government-owned independent power projects, called National Integrated Power Projects (NIPPs). In 2004, the Nigerian government set up a special purpose vehicle to build and own these assets using private sector best practices, in order to address Nigeria’s persistent power shortage. However, the output of these NIPPs fell considerably short of expectations, generating only 600 MW of power compared with the 2,500 MW that was planned.

The privatisation of the NIPPs has attracted interest from the international investor community and, unlike for the Gencos, it appears likely that international banks will participate in the financing of this phase of the privatisation process.

Existing Challenges

However, challenges still exist. Eight months on, the average Nigerian does not feel the impact of the privatisation due to a number of issues being faced by the successor companies which include:

Gas Supply

One of the main challenges currently faced by thermal Gencos is insufficient gas supply. Despite holding the ninth largest gas reserves in the world, domestic gas supply in Nigeria has always been a challenge due to poor gas infrastructure. Energy companies are reluctant to incur large investment costs unless a cost-reflective tariff is put in place.

According to the Nigerian Petroleum Minister Alison-Madueke, about 750 mmcf/d of gas is supplied to the power sector, resulting in an aggregate generating capacity of 4,000 MW—and adding up to 370 mmcf/d of gas could increase generation capacity to 5,000MW by the end of 2014.
In response to the gas supply shortfall, the government has recently approved temporary intervention measures:

i. A gas price increase from US$1.50/mcf to US$2.50/mcf and US$0.80/mcf to cover transportation costs for new capacity;

ii. A regulatory requirement for gas suppliers to commit to supply agreed gas quantities for so long as they are paid by the Gencos;

iii. Arrangements to allocate an additional 370 mmmscf/d of gas to the power plants as part of the plans to increase Nigeria’s generation capacity to 5,000 MW (including hydro) before the end of December 2014; and

iv. Working with the Central Bank of Nigeria to set up a special purpose vehicle structure to restructure up ₦25 billion (approximately US$156 million) of accumulated debts owed to gas suppliers.

Transmission Infrastructure Holdup

Transmission is currently a major challenge. The Transmission Company of Nigeria (TCN) remains a government entity, despite it being managed by Canadian company, Manitoba Hydro International. TCN continues to operate obsolete transmission equipment and be held back by bureaucratic processes. In July 2014, the Nigerian Minister of Power announced plans to privatise the transmission sector into three separate business units but details of the proposed privatisation have yet to be finalised.

Efficiency and Asset Utilisation

Aggregate Technical Commercial and Collection (ATCC) losses also continue to be a significant issue for the Discos. During the bid process, successful Discos were selected based on their ATCC loss reduction plans over the next five years. However, these plans have had limited success due in part to delays in payment for electricity supplied, wastage and theft of electricity. This affects the Gencos in turn, as the losses are currently being shared by all parties.

Opportunities in the Nigerian Power Sector

Despite the various challenges highlighted above, renewed focus on the privatisation of the Nigerian power sector provides opportunities for international and local investment.

Opportunities exist for the construction of alternative independent power projects, such as coal fired power plants and renewables. The eastern part of Nigeria has rich coal reserves, and, in 2013, the government of Nigeria entered into a memorandum of understanding with a Chinese energy firm to build a US$3.7 billion coal power project which is expected to add 1200 MW of electricity to the national grid.

NBET is already able to buy power from all generation companies and sell this competitively in the open market. The regulator has provided incentives for investments in renewable energy projects including feed-in tariffs, a more relaxed licensing regime, access to land and import duty waivers. Nigeria also has geographic and climatic conditions which are particularly well suited for solar and hydropower projects.

As gas prices become more competitive, particularly in relation to transportation fees, more investors may begin to give greater consideration to investing in gas pipeline infrastructure.

There are numerous opportunities for collaborations between international investors and the successor companies from the first round of privatisation, with the latter requiring the expertise and experience of more seasoned companies.
Any investor considering Nigeria ought to be interested in the progress of the country’s power sector privatisation. The power sector directly impacts and drives all economic activity. The ripple effect from an efficient and productive power sector will be felt across all sectors that rely heavily on power including agriculture, manufacturing and information technology.

The actions of the government have already garnered the interest of a wide spectrum of international investors and it appears that there is the political will to successfully execute a transformation in Nigeria’s power sector. International investors will benefit from a closer inspection of, and familiarity with, the opportunities presented by this exciting development in Africa’s leading economy. ♦
Private Equity’s Love Affair With Oil and Gas —Will the Romance Continue?

Robert Hamill
Sam Webster

Over the past decade, private equity (PE) investment in the energy industry and, in particular, the oil and gas sector has increased dramatically. Fundraising reached an all-time high in 2013, with US$36 billion raised for specific energy-focused funds, and Thomson Reuters estimates that as of August 2014 global PE-backed oil and gas M&A totalled US$5.9 billion for the year, up 48 percent on the same period in 2013.

Some of PE’s biggest names have been at the forefront of this increased investment. KKR, Blackstone, Warburg Pincus and Carlyle have all closed multi-billion dollar funds focused on the global energy sector. They follow in the footsteps of the pioneers of oil investment, First Reserve and Riverstone.

New entrants to the market include Blue Water Energy, a London-based PE firm founded in 2011, which raised $861 million last year and is already putting that money to work. It recently agreed to provide $500 million, jointly with Blackstone, to UK-focused oil company Siccar Point Energy in one of the largest ever private equity investments in North Sea oil.

What Is Driving This Trend?
The oil and gas industry is fundamentally capital-intensive, and as traditional sources of funding became harder to obtain during the economic downturn, PE firms moved in to meet the shortfall. In North America, PE investment historically has focused on the oilfield services industry, downstream sector and the midstream sector. The last few years, however, have seen increased investment in the upstream sector as stock markets have cooled on exploration and the race to develop US shale reserves has intensified.

With the majors continuing to divest non-core assets in the face of pressure from shareholders to improve returns, and independents looking to farm-out stakes, there is no shortage of assets on the market. Despite increasing competition from national oil companies—notably from China—PE continues to be an active buyer. Blackstone is currently closing in on the US$1.2 billion acquisition of Shell’s 50 percent stake in the Haynesville Shale formation in Louisiana, as the Anglo-Dutch major looks to reduce its exposure to North American unconventional assets.
The increased investment has coincided with a cultural shift in the mindset of PE in relation to oil and gas investments, away from the traditional model of a strict three- to five-year investment period to a longer term horizon, often around seven or eight years. This shift has followed an understanding and acceptance of the investment requirements of the upstream sector, where successful exploration tends to lead to significant additional capital requirements rather than instant returns. As a result, PE-backed companies are often under less pressure to hit production milestones than their publicly listed counterparts, freeing them up to pursue longer term strategies.

**Which Regions Are the Focus for Investment?**

Traditionally the vast majority of PE investment in oil and gas has flowed to North America, particularly the United States, although the landscape appears to be shifting. Kosmos Energy, the small explorer initially funded by Warburg Pincus and Blackstone, discovered the huge Jubilee oilfield off the coast of Ghana in 2007 with its partner Tullow Oil, and similar success stories have emboldened PE firms to continue to look further afield. Late last year, Carlyle committed up to $200 million to Discover Exploration, a new E&P company led by the former management team of Cove Energy plc, the African explorer that discovered significant gas finds in offshore Tanzania. Discover Exploration is drilling for oil off the coast of New Zealand.

UK North Sea investment reached record levels of £14.4 billion in 2013, raising hopes that oil and gas production could start to pick up again after years of decline. The investment in Siccar Point Energy follows a number of other PE investments in the North Sea in recent years, including Warburg Pincus and Riverstone’s backing of Fairfield Energy, the acquisition of ATP’s UK assets by Petroleum Equity and HitecVision’s take-private of Bridge Energy UK.

PE firms are also casting their gaze toward emerging markets, where the need for oil and gas funding is exacerbated by thin capital markets and weak banking systems. Africa, Asia-Pacific and Latin America are all target regions for growth, while countries that were previously closed to foreign investment, such as Myanmar and Mexico, begin to open up their oil and gas sectors. In September 2014, Riverstone announced a $225 million commitment to Mexican start-up Sierra Oil, which plans to capitalise on Mexico’s recent energy reforms and bring new technology, such as horizontal drilling, to the country.

**What Next?**

In recent years PE has played an increasingly important role in funding the oil and gas industry. This trend looks set to continue as the global economy recovers, emerging market investments become more viable and PE seeks out frontier deals to achieve the high returns demanded by its investors. Africa is expected to feature in the strategies of a number of PE firms, as political tensions are alleviated and security is restored in parts of the continent. Earlier this year Carlyle closed its first sub-Saharan Africa fund at $698 million, surpassing its target by 40 percent, as it hopes to capitalise on the region’s oil and gas discoveries and growing consumer class.

The oil and gas industry’s need for PE funding shows no sign of abating, and with the oil majors expected to try to divest more than $300 billion of oil and gas assets in the coming years, PE’s flourishing relationship with the sector looks set to endure.
Increasing industrial and personal demand for electricity, uncertain supplies and an urgent need to combat global warming are significant challenges. In order to tackle these challenges, the EU decided, a few years ago, to issue legislation to promote and increase the use of renewable energy. In 2007, the European Council agreed on an Energy Policy for Europe and endorsed, as a mandatory target, a 20 percent share of energy from renewable sources in overall EU energy consumption by 2020.

As a consequence, in 2009, the EU adopted the Renewable Energy Directive (2009/28/EC) to establish a common framework for the promotion of energy from renewable sources. The Directive sets out mandatory targets for each Member State, requiring them to reach a certain percentage of energy from renewable sources in gross final consumption by 2020. To achieve their goals, Member States may introduce support schemes to promote the use of energy from renewable sources. The support can be granted either by reducing the cost of producing energy from renewable sources or by increasing the sales price or volumes of such energy. This may be done through investment aid, tax exemptions or reductions, renewable energy obligation support schemes and direct price support schemes, such as feed-in tariffs and premium payments.

However, whenever governments decide to support certain companies financially, e.g., by reducing their tax burden, these companies may gain an advantage over competitors, which can trigger concerns regarding the compatibility with the EU State aid rules. Under Article 107 Treaty on the Functioning of the European Union (TFEU), all State aid measures are prohibited unless explicitly authorized following prior notification by the Member State concerned. Non-notified aid is deemed illegal and, like unauthorized aid, must be recovered from the beneficiaries by the national governments.

To facilitate the assessment of what constitutes illegal aid and what can still be authorized, on 9 April 2014 the European Commission (Commission) adopted non-binding State aid guidelines (the EEAG) in the energy and environmental sectors covering the years 2014-2020. These guidelines are meant to support Member States in reaching their 2020 climate targets by setting out a method for addressing market distortions resulting from certain support measures for renewable energy sources. The EEAG include certain criteria under which energy intensive companies can be relieved from additional charges for the support of renewable energy.
During 2014, the Commission has carried out several significant and highly political State aid investigations against Member States, including Germany and the United Kingdom, that have supported certain industry players by reducing the financial burden caused by the support for the generation of renewable energy. In addition, the European Court of Justice (ECJ) has recently issued its ruling in a case on the Swedish support scheme for renewable energy, the benefit of which was limited to renewable energy produced in the Swedish territory.

**German Renewable Act**

On 18 December 2013, the Commission opened an in-depth investigation into certain provisions of the German Renewable Energies Act (EEG-2012) to examine whether they were compatible with the EU State aid rules. The German law aims at increasing the share of renewable energy sources in electricity supply, while fossil fuels are set to be phased out by 2050. In order to finance the promotion of renewable energy sources in Germany, electricity providers are entitled to a specific surcharge on all electricity consumers, industrial or household. The exact amounts depend on a number of factors, including the type of renewable energy.

However, to avoid choking the power-intensive industry in Germany with additional financial burden, certain companies—mainly in manufacturing sectors such as metals, cement, glass and chemicals—were granted significant reductions of this surcharge when they exceeded certain levels of electricity consumption and costs. A reduction of the surcharge was also granted when an electricity supplier procured at least 50 percent of its electricity portfolio from domestic (i.e., German) renewable electricity sources (so-called “green electricity privilege”).

The Commission’s concerns in the State aid investigation were focused on two aspects of the EEG-2012: First, the surcharge reductions for energy-intensive companies appeared to provide the beneficiaries with a selective advantage that was likely to distort competition within the EU internal market and, thus, was contrary to Article 107 TFEU. Second, the “green electricity privilege” was seen as resulting in discriminatory tax treatment, thus violating EU’s internal market rules.

The Commission’s investigations were accompanied by high-level German political interventions. Chancellor Merkel warned that the Commission might slow down the EU’s most successful and competitive economy in the name of preserving fair competition. Vice-Chancellor Gabriel claimed that the EU proposals would force many important industrial producers to close down their businesses or to relocate to countries outside the EU. Competition Commissioner Almunia for a long time insisted on the fact that the EEG-2012 had to be modified and brought in line with the EEAG. Due to extensive political debates, the adoption of the EEAG was delayed several times.

However, right after the adoption of the EEAG in April 2014, Germany amended the EEG-2012 and notified the new draft (EEG-2014) to the Commission. Following heavy discussions, the Commission approved the new rules on 23 July 2014, concluding that the EEG-2014 was in line with the new guidelines. The new law still provides for reductions of the EEG-surcharge for certain energy intensive companies. However, the number of beneficiaries has been reduced to those companies that are exposed to international trade. Additionally, the new law provides that the aid will be progressively allocated through tenders which will gradually be opened to operators located in other Member States. Following its approval by the Commission, the EEG-2014 has entered into force in August 2014.

However, the Commission has also indicated that the investigation into the above-mentioned reductions from the surcharge under the EEG-2012 is still ongoing. Under the EEAG, such surcharges can be authorized if a number of specific conditions are fulfilled. If these conditions are not met, however, the Commission may adopt a formal decision requesting Germany to recover from the benefitting...
companies any amounts qualified as illegal State aid for 2013 and 2014. Such a decision is expected before the end of 2014. It could have an enormous impact on many energy-intensive industrial users in Germany if they might have to pay the full amount of the surcharge retrospectively. The difficult issue to be addressed by the German government after such a decision will be how to handle these additional payments. Under the terms of EEG, the surcharges are not to be paid into the public budget, but rather to the network operators, and shall ultimately benefit the producers of renewable energy.

Swedish Renewable Energy Support Scheme

The German position regarding EEG-2012 and EEG-2014 was indirectly supported by a recent ECJ judgment of 1 July 2014 (case C-573/12, Ålands Vindkraft v. Swedish Energy Agency). Similar to the German “green energy privilege” model, the ECJ was faced with the question whether imported electricity produced from renewable sources outside of Sweden had to be considered equally within the Swedish renewable support scheme. This scheme promoted green energy by awarding green electricity production installations with “green certificates” which could be sold to other energy suppliers or users under the obligation to hold a specific amount of such certificates. In that way, the Swedish scheme enabled producers of green electricity to receive additional income.

However, the Swedish green certificates were only granted if the production installation was located in Swedish territory. For this reason, Ålands Vindkraft’s application for such certificates was refused; the company operated a wind farm in the Åland archipelago belonging to Finland. Ålands Vindkraft challenged the decision before the Swedish courts and claimed that the Swedish support scheme infringed the fundamental principle of free movement of goods in the TFEU. The Swedish administrative court referred the matter to the ECJ for a preliminary ruling and asked whether the Swedish electricity certificates scheme was compatible with EU law.

The ECJ held that the Swedish support scheme is compatible with the Renewable Energy Directive, which does not require Member States to extend their scheme to cover green electricity produced on the territory of another Member State. The court also held that although the support scheme is capable of hindering imports of electricity from other Member States, the restriction is justified by the public interest objective of promoting the use of renewable energy sources in order to protect the environment and combat climate change. The Swedish support scheme was therefore regarded as consistent with the principle of free movement of goods.

UK Support to Nuclear Power Plant

The Commission recently also applied the State aid rules for the first time in the nuclear sector. On 18 December 2013, an in-depth investigation was opened to examine whether the UK plans to subsidize the construction and operation of a multibillion-euro nuclear power station at Hinkley Point C in Somerset infringes EU State aid rules.

If this project is completed, it will be the first newly built British nuclear reactor since 1995. Its scheduled start of operations is 2023, and it is the first investment framework in a new generation of UK nuclear power stations, marking a significant moment in the revitalization of the UK’s nuclear power industry.

The UK government intends to establish a system ensuring that the plant operator receives stable revenue (“strike price”) for 35 years, independent from price fluctuations of the electricity wholesale price. When the electricity market price drops below the strike price, the difference will be paid by the government. When the market price is above the strike price, the plant operator will pay the difference to the government (“contract for difference”). This system is set to guarantee the plant operator a fixed level of revenues without exposure to the market risks. Furthermore, the operator will get a State guarantee covering all loans the operator seeks to obtain on the financial markets to fund the construction of the plant.
In its investigation, the Commission examined whether the construction of a nuclear power plant could not be achieved by market forces alone, without any State intervention. The Commission expressed doubts that the project suffered from genuine market failure, in which case public support is contrary to the EU State aid rules. However, the Commission’s position changed after the UK significantly revised its plans supporting the project. On 8 October 2014, the Commission concluded that the modified UK measures to support the project are compatible with the EU rules, as the State aid provided remains proportionate to the objective pursued.

The UK authorities managed to demonstrate that the support measure in question addresses a situation of genuine market failure. The guaranteed fee to be paid by the operator to the UK Treasury was significantly raised with the result that the State support was reduced by more than 1 billion pounds. In addition, the gains generated by the project will be shared with UK consumers as soon as the overall profits exceed a given level. The profit-sharing mechanism will remain in place for the entire lifetime of the project: 60 years.

At the time of this approval, Commissioner Almunia felt the need to underline that investments in the nuclear power sector receive less aid than comparable investments in the field of renewable energy. In the EU, the highest amounts of public support in 2012 went to energy produced from renewable sources, such as solar (£14.7 billion), onshore wind (£10.1 billion) and biomass (£8.3 billion). For conventional power generation technologies, the largest amounts of support went to coal (£10.1 billion), natural gas (£7 billion) and nuclear (£5.2 billion). In the UK, the strike price of electricity produced by the Hinkley Point C nuclear plant is 92.5 pounds per megawatt hour, while for offshore wind plants it is 155 pounds per megawatt hour.

Nevertheless, the opponents of nuclear power fear that the Commission’s approval in this case might set a precedent running counter to the policy to promote renewable energy in the EU. Indeed, Bulgaria, the Czech Republic, Finland, Lithuania, Poland, Romania, Slovakia and Sweden are also considering new investments in nuclear power plants. Austria, which has no nuclear power stations, has declared that it will prepare legal action against the Commission decision before the ECJ, claiming that such subsidies for nuclear power plants are not in line with the EU State aid rules. Austria stresses that the Commission’s decision on the Hinkley project set a bad precedent, because guaranteed feed-in tariffs had previously been reserved for renewable energy, while nuclear power is not regarded as sustainable or as a good option to combat climate change.

Conclusions

Each Member State is free to choose its own energy mix as long as it is compatible with EU State aid rules. There is no general EU competence to set out binding rules in this regard, but the EU has an impact on the energy mix through its powers in other policy areas, e.g., environment. The EU Renewables Directive is a good example for such shared competence and the State aid rules apply on top of them, either horizontally through the EEAG or in individual cases.

Within the existing legislative framework, as described, Germany and Sweden have recently decided to promote renewable energy sources, while the UK has more focused on supporting a nuclear energy project and other Member States are likely to follow in the same direction. As State aid investigations often affect economically sensitive areas, especially in the energy sector, national governments and the Commission have the difficult task to find the right balance between national industries’ interests and compliance with the EU internal market and competition rules.
Brazil’s oil & gas industry and the Brazilian Revenue Service are embroiled in a significant tax dispute regarding the contractual model adopted by the industry and the taxation over outbound payments related to charter agreements. The first component of this dispute refers to the zero percent tax rate of the withholding income tax (IRRF) on outbound payments related to the chartering of vessels. This benefit was introduced in the Brazilian tax system by Law no. 4,862/1965, enacted 50 years ago, and later renewed in 1997 by Law no. 9,481. It is important to bear in mind that this rule was not created specifically to benefit vessels used in oil & gas operations. Rather, it was meant to encourage the general charter of foreign vessels for transportation, considering the lack of sufficient Brazilian vessels at the time.

Another element that should be taken into consideration in the analysis of this dispute is the split of E&P services into charter and services agreements in Brazil. The split is a contractual model created by Petrobras that has been in place at least since the ‘90s. It has been adopted by the oil & gas industry in Brazil and virtually imposed in every tender process by Petrobras or on invitations to bid by International Oil Companies doing business in Brazil. This contractual model determines how to split the global price of service activities that have an intensive asset use into charter and services agreements, with the charter usually holding most of the contractual price (80 to 90 percent). Thus, the material part of the global price is not taxed in Brazil because it consists of outbound payments related to the charter, which are benefited by the zero tax rate of IRRF established in Brazilian legislation.

It should be emphasized that the contractual model adopted by the oil & gas industry was solely created for tax planning purposes. The existence of an agreement with a Brazilian entity, as opposed to a charter-only arrangement, was needed due to the local crew and local content requirements established by labor and regulatory legislation, as well as for
the convenience of paying local costs in Brazilian Reais (avoiding currency exchange rate variation on foreign currency).

Nevertheless, considering the significant tax savings the model has delivered, it is easy to imagine the current mindset of the Brazilian Revenue Service vis-à-vis the oil & gas industry. The tax authorities already perceive the industry as overbenefited due to the existence of tax exemptions applied not only to exploration but also to the development and production phases.

Besides the zero tax rate of IRRF on outbound payments related to the chartering of vessels, the oil & gas industry in Brazil also counts on the special customs regime called REPETRO, which establishes tax suspension of federal taxes levied on the temporary importation of certain goods and equipment destined for exploration, development and production. In brief, REPETRO consists of a tax relief mechanism applied to capital expenditures.

In addition to REPETRO, there is also a state tax benefit on ICMS (a VAT-type tax on sales of goods that also levies on imports) that represents an exemption, or a material reduction, to the ICMS on imports of tangible assets or goods for oil & gas exploration and production.

In fact, the total government taxation on the oil & gas industry was designed during the ’90s, when the sector opened to private investments. At that time, exploration offered high risks to investors, estimated production was between 300 and 500 million barrels of heavy crude oil and oil prices ranged from US$15/bbl to US$17/bbl.

The Brazilian Revenue Service contends that the reduced tax burden should not be applied in the current scenario because pre-salt reserves offer lower risk to investors and oil prices have crossed US$100/bbl multiple times.

There have been at least three “rounds” in the “fight” between the Brazilian Revenue Service and the oil & gas industry over the years, with the tax authorities challenging the oil & gas industry by issuing tax assessments based on several different arguments.

At least since 2002, in the so-called “first round” of the dispute, tax authorities filed assessments against Petrobras and International Oil Companies charging IRRF on outbound charter payments. The tax authorities argued that the concept of “vessel” did not encompass production platforms, FPSOs, drilling rigs, semi-submersibles and jackups because “true” vessels would be exclusively designed for the transportation of people and goods. Currently, those assessments are still being challenged at the administrative and judicial levels and, although decisions have been issued favoring each side, it appears that they are now mainly favoring E&P companies.

In 2004, in the “second round” of the dispute, tax authorities started to file assessments against Brazilian service providers of rig operations (the local party in the charter/services split), arguing that any intercompany amount received from abroad should be considered as revenue and also as part of the services fees paid by Petrobras or International Oil Companies to the service provider.

Because of the split between charter and services, and the fact that there is usually a shortage of funds from the Brazilian servicing entity, tax authorities understood that any foreign amount received by the Brazilian entity was actually repatriation of part of an amount that was paid to the charter party without any taxation, but should have been paid to the local Brazilian entity.

Most recently, the “third round” of the dispute started in 2013 when tax authorities considered that the charter contract is actually a service contract—understanding that the split of contracts is artificial mainly, but not solely, because the contracts are not independent of each other. Because there is only one service agreement, the Brazilian Revenue Service assessed E&P companies for the taxes that levy on the import of
services—IRRF, CIDE (Contribution for Intervention in the Economic Domain), PIS and COFINS (both social contributions on revenues)—adding almost 50 percent of taxation over the remittance of funds to the charterer.

Considering that the reclassification of the charter as a service is a threat to the whole industry model, lengthy litigation is expected if some kind of legislative settlement cannot be developed.

The first step in that direction came recently through Law no. 13,043, published on November 14, 2014. The law clearly foresees the split into charter and services agreements as a valid legal option while establishing maximum percentages for charter revenues in the split, according to the type of vessel, to benefit from the zero percent IRRF rate from January 2015 on.

Although, due to poor wording, there is some uncertainty regarding its actual effects going forward, it is clear that Law no. 13,043/2014 can be used as a logical argument against all three types of assessments thrown so far at the Brazilian oil & gas industry, especially because the law validates the split between charter and services as a concept and specifically identifies some oil & gas equipment as vessels.

However, Law no. 13,043 is far from a cure-all. Since it does not have retroactive effect, fiscal years 2009 to 2014 still can be assessed, and are open to interpretation. Moreover, the law does not expressly list as “vessels” some oil equipment that is currently treated as such by the industry (e.g., production platforms, semi-submersibles or jack-ups). Finally, the maximum percentages for charter revenues established in the new law are unlikely to prevent the shortage of funds from the servicing Brazilian entities.

It is difficult to predict, in the light of the new law, how tax authorities will treat the various mechanisms that will continue to be used to cover this shortage—such as intercompany services and reimbursement agreements, loans and capital contributions. Time will tell!
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