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Latin America is once again on the radar of the international and regional oil and gas industry, service companies, and policy makers. Secular changes in the petroleum investment risk profile of major oil and gas hubs such as Russia, North Africa, West Africa, and the Middle East, limited access to acreage in the traditional producing areas, as well as the lack of new exploration successes outside the emerging provinces such as East Africa and the Eastern Mediterranean, among others, have made Latin America an interesting place to re-visit. These circumstances have coincided with the North American unconventional boom and Mexico's landmark reform that brought the Americas back onto the industry map again.

Since the pre-salt discoveries in Brazil – which are underway to reach their first production milestone – were first announced in 2007, a new wave of diverse potential opportunities has emerged. These include: the giant unconventional resources in Argentina, deepwater in Uruguay, frontier deepwater and unconventionals in Colombia, and the opening of already discovered reserves and exploration opportunities in deepwater, shallow water, onshore and unconventionals in Mexico.

Yet despite substantial reserves and yet to be found hydrocarbons, Latin America is increasingly becoming dependent on imports of gas and refined products. In fact, the energy trade balance of major oil producers/exporters such as Venezuela and Mexico no longer looks that favourable, whilst Brazil continues to review its domestic pricing policy after having lost its self-sufficiency in the midst of a challenging macroeconomic environment. Structural issues are likely to prevent any reversal of these trends in the years to come, unless radical reforms are enacted, as in the case of Mexico.

The energy-related relationship of the region with the world, and especially with the USA and the international industry, is being re-evaluated as its profile gradually shifts from that of an exporter of commodities towards one of an importer of petroleum products.

The recent drop in oil prices is generating anxiety in the producing countries in the region due to the major destabilizing effects that could result on their fiscal balances. The prospect that prices may settle at much lower levels than were seen in the last decade is generating a wave of measures to improve the investment climate and consequently mitigate the impact of lower revenues: on the one hand, increased exploration and development would lead to higher production and, on the other hand, private investment may substitute the substantial investments needed every year in the producing

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countries with large NOCs. The problem is that lower oil revenues also affect industry, forcing operators to review their investment portfolios to focus on the best regimes and geological prospects.

The region's recent positive developments are taking place against a background where a large number of countries in the region (including Argentina, Venezuela, Bolivia, Ecuador, French Guyana, and Suriname) have fallen out of favour with oil and gas investors, in some cases for a number of years. Even Colombia and Peru, two of the regional stars of the last decade, will need to step up their efforts to maintain their attractiveness.

Unlike the major international oil and gas industry hubs and hydrocarbon-rich regions of Russia, Africa, and the Middle East, Latin America traditionally has not been able to attract long-term capital or seen many sustained full-cycle developments in oil and gas (in contrast to the situation in mining, where activity has been stable). Latin American NOCs, a handful of medium-sized regional players, and newly formed companies for specific opportunities clearly dominate the landscape and have seen more success than any industry group.

In this issue of the *Forum* we cover several regional themes that will shed some light onto the challenges and opportunities for the region, as well as some specific country themes.

Aldo Flores-Quiroga covers cooperation in the region and concludes that if Latin America is to create a robust and resilient energy sector – one that is ready for the opportunities that lie ahead in the 21st century and that at the same time strengthens energy security for all its people – the governments of the region will have to muster the political will to overcome inertia, cooperate with each other, and take more decisive steps towards greater energy integration.

The attractiveness of Latin America and the challenges facing policy makers are addressed by *Thomas Conway*. He concludes that policymakers in Latin America are confronted with the difficult task of ensuring that their hydrocarbon sector regulatory and policy frameworks are sufficiently competitive to bring in the necessary capital and technology.

The region's oil outlook is reviewed by *Lucian Pugliaresi* of EPRINC; his main conclusion is that from a strictly technical view, Latin America's major petroleum producing provinces could substantially raise oil production over current levels.

Experience in the USA, Canada, and Colombia demonstrates that improved extraction techniques, sound application of new production technologies, and sustained investment coupled with stable contract terms and contained political risk would likely yield continued production growth. However, uncertainty above the ground will largely remain.

Anouk Honoré reviews the region's natural gas outlook and concludes that political decisions, maybe more than economic logic, have shaped gas developments in Latin America and with a fast-rising gas demand outpacing indigenous production, the region is on track to becoming a sizeable importer of LNG. Under some scenarios, LNG may return to being a marginal source of supply and therefore the growing interactions of Latin America with the global gas market may be only a passing phase.

In-depth articles covering the shale boom in Argentina (*David Mares*) and Colombia's efforts to materialize its vocation as an energy hub (*Armando Zamora* and *Hernán Martínez*); Brazil's pre-salt outlook (*Virendra Chauhan*), local content challenges (*Edmar de Almeida* and *Diana Martinez-Prieto*), and natural gas (*Ieda Gomes*); and Mexico downstream (*Adrián Lajous*) and upstream market opening (*Ivan Sandrea* and *Read Taylor*) have also been included.

This issue is the first of a series that the editors will be bringing together in the future as a way of contributing to an independent and academically oriented forum for the exchange of information and analysis about energy issues in Latin America.

The region has considerable potential to provide energy solutions to the world and to convert its natural endowment into better-shared prosperity for its people. We invite our readers, colleagues, and friends to join us in this initiative and contribute their views and analyses on this topic.

Whither energy cooperation in Latin America?

Aldo Flores-Quiroga

Two features of Latin America's energy sector – its position as a net energy exporter and the recent build-up of LNG importing facilities on both its Atlantic and Pacific coasts – illustrate both the potential for energy cooperation in the region and the associated pitfalls. The first, which is an expression of energy abundance, hints at the promise of integration; but the second suggests this might be wishful thinking, at least for the time being. The future of Latin American energy cooperation will depend largely on which of these two conflicting tendencies prevails.

Existing energy linkages

In a region where primary energy production exceeds consumption by 60 per cent, and where energy resources are distributed unevenly, the opportunity to link energy-rich countries with their energy-poor counterparts suggests itself almost immediately. It is hardly surprising that Mexico and Venezuela export part of their oil surpluses to the countries of Central America and the Caribbean, which do not produce oil in significant amounts, or that Paraguay and Argentina export some of their surplus electricity to Brazil and Uruguay. Likewise, it is understandable that gas-rich countries are linked with their neighbours through pipelines: for example Argentina with Chile, and Bolivia with Brazil.

'… A REGION WHERE PRIMARY ENERGY PRODUCTION EXCEEDS CONSUMPTION BY 60 PER CENT …'

Moves towards LNG imports

But it is striking that, while abundance and asymmetry are allies in the promotion of energy integration and go a long way towards explaining the pattern of intra-regional trade, over the last decade the countries of the region have prioritized investments to increase domestic gas supply with indigenous production and/or imports from the rest of the world. Brazil and Chile have built LNG facilities to diversify their imports of natural gas away from gas-rich Argentina and Bolivia despite the considerable abundance of hydrocarbon reserves in Mexico's Gulf Coast, South America's Atlantic coast, and the Andean countries; Venezuela and Mexico, which have large untapped gas reserves, do not produce sufficient to satisfy their own needs, let alone enough to export to Central America.

The reasons behind patterns of energy relations in the area are numerous; they derive, among other factors, from the interaction of geography, politics, and economics.

Geography: regional energy markets

Latin America is vast, being composed of four sub-regions separated from each other by oceans, mountains, and rainforests. The distance between demand and supply centres presents a significant challenge within each sub-region, let alone among sub-regions; this has a significant impact on the scale and cost of energy projects that might interconnect. The northernmost region – comprising Mexico and Central America – can only connect to South America through the Central American isthmus. The islands of the Caribbean are well-separated by water from the rest of the continent. In South America, the Andes and the Amazon rainforest present a formidable natural barrier between the highlands in the north and the lowlands in the south. Initiatives to forge stronger energy links, therefore, tend to be concentrated within each sub-region. Mexico and its Central American neighbours have been building interconnections over the last decade to create a regional electricity market that makes the best of the sub-region's diverse resource base. Gas integration, however, has eluded them in the absence of a strong demand anchor in either the power or manufacturing sectors of Central America. In the Caribbean, the strongest trade links take place through tanker trade with, among others, Venezuela and Mexico and in some cases through pipelines with Trinidad and Tobago. The countries of the Andean region have pursued a similar strategy for electrical integration as those of Central America; they have exceeded Central America's progress on the gas front, as Colombia exports to Venezuela and Peru to Chile. Farther south, Argentina, Brazil, and Paraguay have invested jointly in large hydroelectric projects to tap their shared water resources. Bolivia is linked through gas pipelines to the Argentine and Brazilian markets, while Argentina is linked to Chile and Uruguay, and Colombia is linked to Venezuela.

Effect of politics on cooperation

Consider now the political constraints on integration. Due to the particularities of the region's political processes – where disputes about the ownership and distribution of rents from oil and other natural resources persist – investment regimes in various countries have shifted at least twice in the space of the last two decades. This has left Latin America's policy orientation divided between the statist-leaning Atlantic Basin and the relatively more

market-oriented Pacific Basin. In the Andean region, Venezuela, Ecuador, and Bolivia have adopted a more restrictive regime for private or foreign investments than Chile, Colombia, and Peru, since the early 1990s. Among the countries of Mercosur (Argentina, Brazil, Paraguay, Uruguay), while the trend toward greater openness in investment regimes was not reversed, Argentina and Brazil adopted measures favouring either state-owned or domestic private companies. And Bolivia and Argentina nationalized oil and gas assets just as their neighbours privatized some of their own. The Central American and Caribbean countries have maintained relatively open regimes; as recently as 2014 they were joined by Mexico, when it changed the position it had taken for 70 years by opening its energy sector to private investment.

'THIS HAS LEFT LATIN AMERICA'S POLICY ORIENTATION DIVIDED BETWEEN THE STATIST-LEANING ATLANTIC BASIN AND THE RELATIVELY MORE MARKET-ORIENTED PACIFIC BASIN.'

Different national perspectives relating to the ownership of energy resources and the role of markets versus states, while legitimate, have slowed down and even blocked promising joint projects. Without the explicit agreement of governments to work together, clear guidance about objectives and the rules that would apply for projects involving more than one country have been insufficient.

Development of domestic projects

The energy industry has therefore come to prefer investments that limit its exposure to regime uncertainty. In South America this has implied less emphasis being placed on cross-border energy links and more on the development of domestic projects. Companies did build pipelines and electrical interconnections in the 1990s; these were capital intensive and location specific on both the supply and demand sides. However, following shifts in investment regimes in Bolivia (which nationalized its gas industry), Venezuela, and to some degree Argentina that raised questions about regulatory frameworks, enthusiasm for investments that provide greater flexibility (such as the LNG facilities mentioned earlier) increased. Investments in refining capacity and other downstream assets continue to lag throughout the whole region; this maintains its dependence on extra-regional imports of oil products.

'THE ENERGY INDUSTRY HAS THEREFORE COME TO PREFER INVESTMENTS THAT LIMIT ITS EXPOSURE TO REGIME UNCERTAINTY.'

Economic factors affecting energy cooperation

Moving on to economic factors, the confluence of adverse macroeconomic conditions, rising cost structures, and globalization altered the assumptions supporting some binational and multinational integration deals. This led to suspensions or to delays in the execution of projects. Pipeline trade was supposed to flourish between Argentina and Chile, but the exchange rate realignment triggered by Argentina's economic meltdown in 2001 reduced the cost of gas to Argentina's domestic consumers, who started using more of this fuel, thereby reducing the surplus available for export. The greater demand for Argentine goods following devaluation, together with Asia's large appetite for commodity imports from South America, reinforced this trend. After experiencing a supply disruption, Chilean authorities decided to hedge their bets and initiated projects to build LNG import facilities.

Similar decoupling responses have taken place elsewhere in the region as a consequence of economic forces. Divergent interpretations regarding electricity prices and demand behaviour, which remain largely unresolved, have affected relations between Paraguay and Brazil (who share the large Itaipú hydropower plant). Paraguay would prefer more favourable terms for electricity trade than those it originally agreed to. For a long time, thin electricity markets in Central America have slowed down the pace of integration projects in the region; this has proved to be an obstacle to the construction of both a pipeline connecting the countries from Mexico to Colombia and a new sub-regional refinery.

Inter-government structures for energy cooperation

These difficulties on the ground are in stark contrast with the agreements and official statements from Latin America's leaders relating to the importance of, and commitment to, integration. Throughout the past five decades the region's governments have signed numerous bilateral and multilateral instruments and official documents expressing their willingness to cooperate toward this goal, and together with the private sector they have laid the legal groundwork for more open intraregional energy trade and investment through the formation of a number of organizations. The Latin American Integration Association (ALADI) was created in 1960, and was transformed in 1980 into the Latin American Free Trade Association (ALALC). This provided the framework for integration through freer trade, including that of energy. The Organization of Latin American and Caribbean Energy Cooperation

(OLADE) was established in 1975. OLADE is a sort of Latin American counterpart to the International Energy Agency, but without the requirement for strategic reserves. The 1960s also saw other initiatives such as the Regional Commission for Energy Integration (CIER), and industry associations like the Latin American Association of Oil and Gas Companies (ARPEL). Many of these objectives have been incorporated recently into the Union of South American Nations (UNASUR) and the Community of Latin American and Caribbean States (CELAC), which also emphasize respect toward each member nation's legal framework. Alas, realities like those noted above have superseded the best intentions of governments and industry leaders.

Achievements

Where successes have been possible – even notable in breadth and scope – they have relied on the agreement of a smaller subset of actors and have coincided with episodes of greater political compatibility among the region's governments. The San José Accord of 1980, signed by Venezuela and Mexico, provided oil supply guarantees and funding to the countries of Central America and the Caribbean for over two decades; this was especially important at times when international market forces could have pulled crude shipments away from them and toward Europe or Asia. PetroCaribe, a Venezuelan initiative launched in 2005, signalled the end of the San José Accord, while expanding its benefits for a longer time period to a larger set of countries. The Central American electricity grid is part of a sub-regional integration initiative (SIEPAC) managed through a consortium of the power utilities of the countries, which include Mexico. The South American hydroelectric projects of Salto Grande, Itaipú, and Yacyretá (executed in the 1970s and 1980s) are impressive bilateral cooperation agreements involving Argentina and Uruguay, Brazil and Paraguay, and Argentina and Paraguay respectively.

Energy efficiency and renewable energy

As more ambitious integration efforts have floundered, or run into complications which are difficult to address in the short term, regional cooperation has focused instead on less controversial areas, such as the promotion of energy efficiency and renewable energies. Energy efficiency is perhaps the one subject where it is easier to find consensus, considering that all governments support it as an objective, provided it is not linked to concrete goals for reduction in greenhouse gas emissions or energy intensity. Under the umbrella of regional energy organizations such as OLADE, countries have been exchanging their experiences in these areas while providing more opportunities for training and joint research projects.

'LATIN AMERICA CAN RIGHTLY CLAIM LEADERSHIP IN [RENEWABLE ENERGY], AS IT IS PERHAPS THE REGION WITH THE CLEANEST ENERGY MATRIX IN THE WORLD.'

With respect to renewable energy sources, governments are placing greater attention on technical and scientific cooperation. Latin America can rightly claim leadership in this area, as it is perhaps the region with the cleanest energy matrix in the world. Brazil is a champion in hydroelectricity and biofuels. Mexico has recognized strengths in the use of geothermal energy. And the considerable potential that most of the countries have in wind, solar, and geothermal sources, where it is already making progress, is also attracting more interest. OLADE has served as an important venue for the exchange of information and training in these areas.

Conclusions

So where does Latin American energy cooperation stand? Excluding oil and coal trade, and an LNG market that involves Peru and Trinidad and Tobago as the only regional suppliers (so far), most Latin American countries have pursued either an inward-oriented energy strategy or have tried to find reliable energy partners – producers and consumers alike – beyond the Western Hemisphere. Energy links *within* each sub-region do exist, and there is enough infrastructure to attest to this, but they have not been used or developed to their full potential.

Perhaps paradoxically, deep integration in a region rich in energy resources remains elusive, even as it is increasingly needed. As the region's income level and population increase, its energy demand is expected to grow at a much faster pace in the coming decades, reducing its export surplus. Its energy matrix is likely to rely more on natural gas for electricity generation, and this might be cheaper to consume from the region itself than from abroad. The region's demand for oil products, especially diesel, is set to increase as its transportation fleet expands. And the region still faces the moral debt of energy poverty: more than 30 million Latin Americans still lack access to modern energy services.

'PERHAPS PARADOXICALLY, DEEP INTEGRATION IN A REGION RICH IN ENERGY RESOURCES REMAINS ELUSIVE, EVEN AS IT IS INCREASINGLY NEEDED.'

It will be difficult to address these challenges without greater integration and cooperation. There is widespread recognition that greater interconnectivity of electricity and gas markets throughout the region has the potential to reduce investment costs and expand energy access. It would

also facilitate the development of renewable energies on a larger scale and promote an even cleaner energy matrix. And Latin America can play a much more significant role in the promotion of global energy security by strengthening its own energy system. For this to happen, increased trust and joint planning of energy strategies will be required. If Latin America is to create a robust and resilient energy sector – one that is ready for the opportunities that lie ahead in the twenty-first century, and that at the same time strengthens energy security for all its people – the governments of the region will have to muster the political will to overcome inertia, cooperate with each other, and take more decisive steps towards greater energy integration.

Global competition for upstream investment: key test for Latin America's policymakers

Thomas Conway

Latin America is back on the industry radar, but the world is a different place

In the last five years, Latin America has re-emerged on the world stage of global upstream opportunities. Brazil has proved up its massive pre-salt trend boasting tens of billions of barrels of potential. Argentina, seen as a mature producer well past its prime only a few years ago, has a new lease of life in its world-class Vaca Muerta shale province. In August, Mexico completed far-reaching energy reform; many in the industry had long hoped for this, but it had seemed politically unthinkable even after President Enrique Peña Nieto had submitted his proposal to the legislature a year earlier.

If Latin America's re-emergence had taken place in an environment of restricted resource access for major companies, the key questions for the region's policymakers would have centred on how to maximize the value for the benefit of their respective countries. The ability to attract any needed investment from outside companies would have been almost a given. This was, in fact, the status quo during much of the 2000s. But that has now changed.

'Today we clearly have more opportunities than we can develop ... we are not project constrained, we are more capital constrained'. Former Shell CEO Peter Voser's words from the 2013 Oil & Money conference still ring true not only for Shell but for major oil and gas companies more generally. Constraints to resource access were seen as the critical issue for the industry until just a handful of years ago. In the last decade, limited resource access gave resource-holding states leverage to tighten contract terms and strengthen the role of the state in hydrocarbon sector development. Well before the latest softening of oil prices, however, the proliferation of North American unconventionals opportunities, in combination with other global offshore, LNG, and extra-heavy oil projects, led to a general perception that the industry was no longer lacking opportunities. Instead, rising cost pressures, particularly in key megaprojects, have become the top obstacle. In response, players in the industry are shifting their focus towards value rather than growth – greater efficiency is now more important than increases in reserves and production for many firms.

Policymakers in Latin America are thus confronted with the difficult task of ensuring that their hydrocarbon sector regulatory and policy frameworks are sufficiently competitive to bring in the necessary capital and technology, even as key countries like Argentina and Brazil are seeking to adapt their regimes to an expanding and increasingly strategic resource base.

'… GREATER EFFICIENCY IS NOW MORE IMPORTANT THAN INCREASES IN RESERVES AND PRODUCTION FOR MANY FIRMS.'

Effective policy and regulation: one size does not fit all

Evolving, often ideologically driven, perspectives on the optimal role of the state have often led to policy shocks. But in Latin America, as with other countries, there is no detailed blueprint for effective and successful regulation and policy. In some cases, such as the USA, a limited state role, a dominant private sector, and strong market orientation yield successful results. However, countries with capable state companies and a more limited reliance on market forces, like China or Saudi Arabia, also perform well within their specific contexts.

Effective and sustainable hydrocarbon sectors share three characteristics. First, the investment regime is stable. At the highest level, this refers to the political and economic environment;

underpinned by durable and effective institutions, economic and political volatility is generally limited. Political transitions are orderly, while the economy is well-managed at both peaks and troughs of the business cycle. Changes in policy and regulation can still be common – and in cases such as the emergence of new resource potential, policy shifts are often the best course of action for investors and governments alike. The second component, however, is essential: that any changes in policy and regulation are generally predictable. This does not mean that investors are able to anticipate future changes down to the last detail but rather, for example, that if a new government comes into office investors have a general understanding of its policy orientation and of the degree of changes it is willing to make. Third, effective and sustainable oil and gas sectors have supportive operating conditions which include: well-developed infrastructure, adequate security, capable human resources, sound rule of law, and sufficiently attractive contract terms, among others.

Crucial for success – and more of an art than a science – is for policymakers to craft a regulatory and policy framework that fits with local conditions. The top objective for policymakers is to implement reforms that are politically and economically sustainable. Dramatically opening an oil and gas sector to private investment in a country where most citizens have historically opposed such a reform is bound to generate a destabilizing backlash – as witnessed following the 'Capitalization' programme in Bolivia in the 1990s, for instance. Similarly, the instability caused by price liberalization, if implemented poorly, could prove to be worse than keeping subsidies in place in the short term, especially for weak states. Probably the most memorable regional example of this is the fuel price liberalization that sparked the 1989 'Caracazo' in Venezuela. A sustainable reform agenda will take into consideration a state's appetite and capacity to implement new policies.

Effective energy reforms will also align with a state's core energy sector objectives, which can vary from one case to the next. For some countries, energy security and self-sufficiency are the main priorities, while for others the addressing of revenue needs is paramount. Alternatively, broader economic aims – such as supporting industrialization through local content goals or ensuring affordable energy for particular sectors – can be the most pressing. Brazil's hydrocarbon sector opening in 1997, for example, was important for boosting investment, raising production, and, ultimately, approaching Brasilia's central goal of oil self-sufficiency. At the same time, the local content requirements included in each licensing round guaranteed opportunities for Brazilian industry to increase its capacity, which aligned with the country's historical policy orientation in this regard.

'EFFECTIVE ENERGY REFORMS WILL ALSO ALIGN WITH A STATE'S CORE ENERGY SECTOR OBJECTIVES . . .'

Successful reforms will also take into consideration the existing competitive landscape. Although fully privatized oil and gas sectors can be among the most successful, full privatization is probably not the best fit in a country with a highly capable national oil company. The appropriate role for the private sector will depend on the capabilities and needs of the state companies. A more effective approach could be to build upon a NOC's strengths through partnerships and competition that bring in the needed capital and technology. Indeed, it is the model that Brazil and Colombia have successfully adopted – and Mexico is now following in their footsteps.

Finally, under a sustainable regulatory and policy regime, host governments will provide sufficient incentives to attract the needed investment, given country-specific risks as well as the rewards on offer. In many cases, states rely on international oil companies for financial and technical support, either in partnership with the NOC or on their own. Offering the appropriate incentives – in the form of contract terms, rule of law, regulatory independence, and adequate operating conditions, among other things – is fundamental.

Latin America: emerging era of competitiveness

In the last two and a half decades, the regulatory and policy landscape in Latin America has swung in and out of favour with investors – in some cases quite dramatically. The time period between the early 1990s and the present day can be broken down into three eras based on government approaches to policy and regulation.

In the **neoliberal era** of the 1990s, several countries focused on privatization of state companies and opened hydrocarbon sectors to foreign investment. Argentina under Carlos Menem and Peru under Alberto Fujimori arguably went the furthest in this regard, by fully privatizing NOC YPF in the case of the former, and selling off all of NOC PetroPeru's upstream assets in the latter. Bolivia's 'Capitalization' of YPFB in 1996 split the NOC into two upstream units and sold operating stakes to separate consortia of private companies. Brazil also underwent a major oil opening, during Fernando Henrique Cardoso's presidency in 1997. This reform – which introduced private sector competition, created an independent regulator

and licensing agency, and partially privatized Petrobras – served as an important model for Colombia and Mexico.

'THE REGULATORY AND POLICY LANDSCAPE IN LATIN AMERICA HAS SWUNG IN AND OUT OF FAVOUR WITH INVESTORS.'

The neoliberal paradigm proved unsustainable in the 2000s, however, as shifting political winds in many countries, together with rising commodity prices, led to a re-evaluation of the state's role in the economy and the hydrocarbon sector. The **statist era** – which coincided with sweeping political changes in several countries – resulted in hydrocarbon sector policies in Bolivia, Ecuador, and Venezuela that emphasized tighter contract terms for investors, a stronger role for NOCs, and in some cases the expropriation of assets. Brazil, motivated more by the discovery of the strategic pre-salt resources than by political changes or oil price dynamics, established a new investment regime in 2010 for unlicensed pre-salt acreage that guaranteed Petrobras operatorship. Finally, Argentina – facing declining oil and gas balances and arguably a hydrocarbon sector framework that was out of line with the policy priorities of President Cristina Fernández de Kirchner – took over YPF from Repsol in 2012.

Colombia took what may be best described as a contrarian approach during the statist era with its 2003 reform. Under Alvaro Uribe, Colombia introduced private sector competition into the hydrocarbon sector (removing the NOC's monopoly), created an independent regulator and licensing agency, and partially privatized Ecopetrol. The improved security environment in the country was also a critical factor. The policies paid dividends, attracting significant investment at a time of growing pessimism for investors in neighbouring countries.

Now, however, a new era has dawned. With the proliferation of opportunities and an easing of access constraints as outlined above, resource-holding states have lost leverage and are increasingly concerned about the competitiveness of their investment regimes. The recent softening of oil prices places even greater pressure on these governments to improve entry terms and operating conditions in order to attract investment. The approaches that are emerging in this **era of competitiveness** also appear to be more pragmatic and less ideologically driven than in eras past.

Mexico's energy reform is the most prominent example in the region. Mexican policymakers clearly took into consideration the global context in the formulation of the country's policy and regulatory framework. The reform has, at the same time, addressed critical factors that threatened the long-term sustainability of the hydrocarbon sector. It grants PEMEX greater financial autonomy and flexibility to strike partnerships in order to meet its technical and financial needs, while also forcing the NOC to compete against private firms across the value chain, with the aim of growing overall investment in the sector.

The Mexican oil opening is, in turn, yet another factor spurring others in the region to improve the competitiveness of their investment regimes. Colombia, for instance, is considering how it can reinvigorate interest in its sector, following a licensing round in July that did not meet expectations. The bid round has sparked fears that investors are turning their attention away from opportunities in Colombia as Mexico looks more promising, while many of the onshore conventional opportunities in Colombia face growing operational difficulties which include more cumbersome environmental licensing, community activism, and security challenges.

'THE APPROACHES THAT ARE EMERGING … APPEAR TO BE MORE PRAGMATIC AND LESS IDEOLOGICALLY DRIVEN THAN IN ERAS PAST.'

In Brazil, the president will likely consider altering entry terms, particularly in the pre-salt, to boost investment following the 2010 reform that increased the role of the state and tightened terms in unlicensed pre-salt areas. Argentina has made incremental improvements to investment terms for investors, post-YPF nationalization (although economic and political uncertainties still prevail). These policy steps have paved the way for major partnership deals in the Vaca Muerta between YPF and foreign players, namely its joint venture with Chevron to explore and develop Loma Campana and PETRONAS's most recent tie-up with YPF. Even Ecuador is more actively seeking investment in its sector, including its undeveloped crown jewel, the Ishpingo-Tambococha-Tiputini (ITT) complex.

As this diverse set of countries pursues regulatory and policy adjustments, Venezuela looks increasingly like an outlier in the region. Characterized by economic malaise and stagnation in oil and gas sector operations, the Maduro administration faces an array of policy challenges with no clear path ahead. This is compounded by a lack of political will and capacity to carry out the structural economic reforms likely to be needed for appreciable growth in investment and production in the hydrocarbon sector.

Outlook: zero-sum game?

As various countries seek improvements in their investment

regimes in the coming years, it remains to be seen whether the competition for global investment dollars will be a zero-sum game for the region. Large companies focused on efficiency, and seeking to balance their portfolios geographically, are likely to be more selective in their investment decisions. They could very well shift focus within Latin America rather than increasing overall investment in the region. Some independent E&P companies are facing shareholder pressure to exit international operations and focus on North America – this was exemplified by Apache's Argentina exit earlier this year. Smaller regional E&Ps with more limited financial resources will also carefully weigh the allocation of scarce investment dollars.

Nevertheless, Latin America's emerging world-class resource potential in Mexico, Brazil, and Argentina might attract players to increase their exposure to the region. In the past several years, Asian NOCs have shown a particular interest in expanding their Latin America positions in an effort to diversify away from other regions, such as the Middle East and Africa. The Chinese NOCs have been at the forefront of this trend but others, such as India's ONGC and Malaysia's PETRONAS, are also making important moves.

The Mexican oil opening is also likely to bring unique investors to the region, given its diversity of opportunities and its proximity to important US shale plays, such as the Eagle Ford and the Permian. Majors and independent E&Ps with a presence in the US Gulf of Mexico will likely be attracted to new deepwater opportunities. It will also lead to the growth of a new group of players: Mexican E&P independents.

Will Latin America join petroleum's new world order?

Lucian Pugliaresi

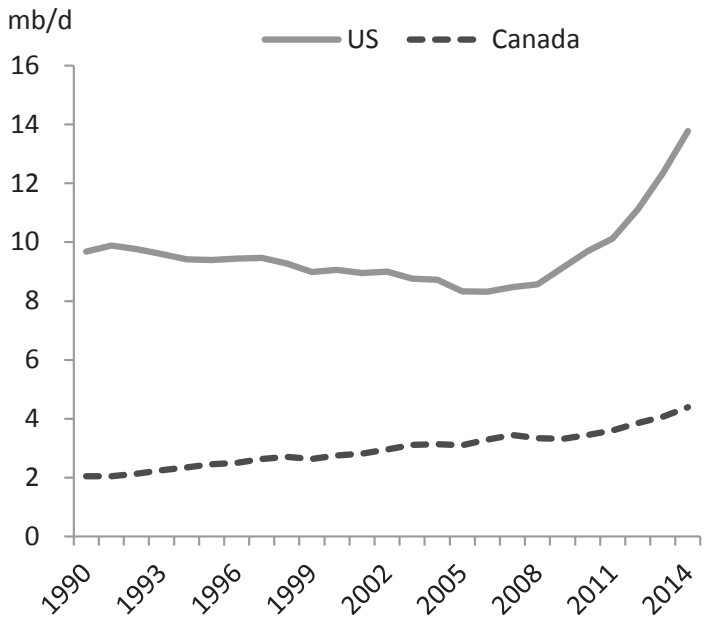
Introduction

The surge in crude oil and natural gas liquids production from the USA and Canada, totalling over 6 million barrels/day (mb/d) since 2006–7 (see graph on right), is a remarkable achievement of technological innovation and risk taking. This liquids growth arrived on the heels of large-scale and low-cost development of natural gas supplies from so-called tight or unconventional formations. US production growth has been driven by long-term improvements in the application of both the art and science of horizontal drilling and hydraulic fracturing.

In the years just prior to the emergence of the US petroleum renaissance, Canada achieved substantial improvements in both mining and steam-assisted gravity drainage (SAGD) extraction techniques from the McMurray Formation in the Western Canada Sedimentary Basin. These North American (sans Mexico) unconventional petroleum developments are altering flows in world crude oil trade, shifting long-term price expectations, and challenging long-held conventional wisdom on US energy policy promulgated in an era of scarcity.

Lessons from the US and Canadian production surge

An important feature of the rapid expansion in US production is that it



US and Canadian crude and natural gas liquids production, million barrels per day (mb/d)

Sources: Canadian Association of Petroleum Producers, EIA

occurred entirely on private land outside the jurisdiction of the federal government; this permitted development to take place quickly and largely unimpeded. Oil and gas production from federal land has become highly contentious and subject to cumbersome and often cavalier regulatory oversight, court delays, and intractable political gridlock. As the recent surge in US oil and gas output took place on private land, the permits and environmental regulations were handled largely by local authorities, without the typical long delays and financial risks prevalent in projects developed under the jurisdiction of the federal government. In a stunning turnaround, the USA is now the world's number one oil and gas producer – having previously been written off as a petroleum province undergoing permanent decline.

Both the US and Canadian experiences offer substantially different risk profiles for petroleum investment. The all-in per barrel cost of shale resource development is costly by world standards (US$50/barrel or more), but financial and project risks are low as total costs are modest and revenue begins to flow within months. Most shale developments do not require risking large capital outlays over long time periods before first production.

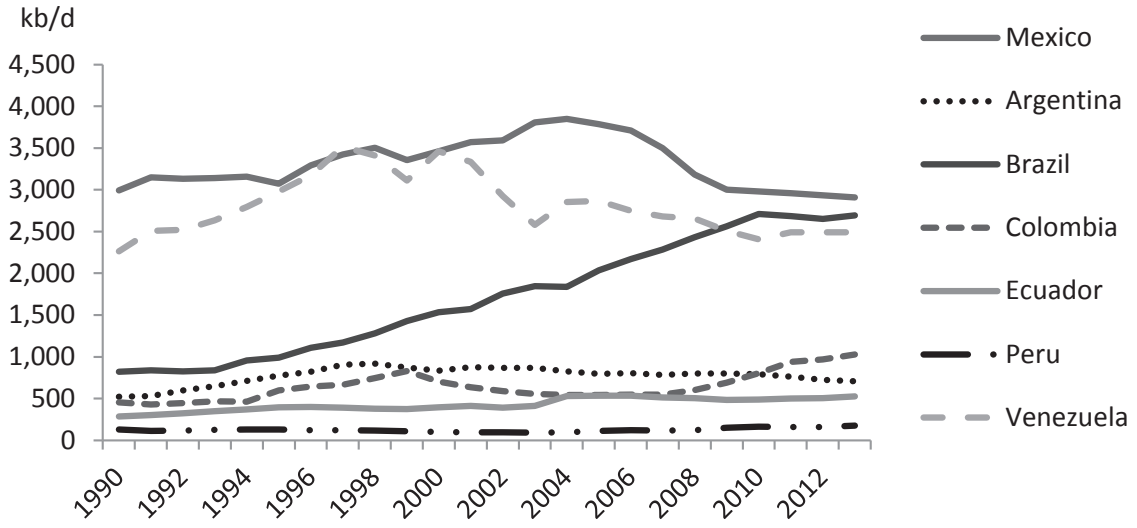
'MOST SHALE DEVELOPMENTS DO NOT REQUIRE RISKING LARGE CAPITAL OUTLAYS OVER LONG TIME PERIODS BEFORE FIRST PRODUCTION.'

In contrast to the US experience, the Canadian production surge is almost entirely from 'Crown' properties. However, sustained reform of Canadian leasing procedures – administered by the National Energy Board (NEB) of Alberta and the Alberta Energy Regulator – has fostered a predictable and long-term programme to bring in investment from both IOCs and NOCs. (The commercialization of the oil sands benefitted from a royalty relief regime wherein projects paid 1 per cent royalty until initial capital costs were recovered, before moving to the prevailing royalty rate.) Canadian oil sands development is capital intensive and is characterized by a substantial delay before first production, but investors remain confident that they can manage regulatory and political risk in Canada.

What about the rest of the Western Hemisphere?

The US and Canadian experiences have demonstrated that very different development models can deliver high volumes of oil and gas production if the appropriate technology and reserves are available and above-the-ground risks can be contained. Recent production trends show less impressive results from Latin America (see graph below).

The most significant production growth has come from Brazil, which successfully attracted the participation of international oil companies (IOCs) in the development of its offshore pre-salt reserves. Sustained and well-managed economic reforms in Colombia have delivered an investment-friendly development programme for several years now. Notwithstanding these improvements, production losses from Venezuela, Mexico, and Argentina have contributed to stagnant performance for the region as a whole. Latin American crude oil production in 2012 came in at 10.3 mb/d, roughly



Latin American crude oil production, thousand barrels per day (kb/d)

Source: EIA

the same volume as the region produced in 2002.

The production performance in Latin America cannot be blamed on inadequate reserves. According to the US Energy Information Administration (EIA) Latin America has proven hydrocarbon reserves only second to those of the Middle East. Even if we ignore pending evaluations for deep water and shale reserves Latin America, with 20 per cent of the world's total, has the largest proven hydrocarbon reserves outside the Middle East, which has 48 per cent. (Although it is too early to make any firm conclusions on the ultimate performance of shale resources in Latin America, a report by the EIA and Advanced Resources International (ARI), released in June 2013, identified liquids-rich prospective shale formations in the Americas, such as Vaca Muerta in Argentina, Eagle Ford in Mexico, Ponta Grossa in Brazil, and La Luna/Capachu shared by Colombia and Venezuela.)

'THE PRODUCTION PERFORMANCE IN LATIN AMERICA CANNOT BE BLAMED ON INADEQUATE RESERVES.'

Oil reserves in the region are distributed unevenly. Venezuela dominates the region with 297 billion barrels of proved reserves. The country's large reserve endowment is mostly extra-heavy, with characteristics not unlike those of the Canadian oil sands. Venezuela more than tripled its official reserves in the last five years due to a combination of high oil prices, technological advances, and actual experience with extra-heavy oil extraction and marketing. Its reserves are the world's second largest after Saudi Arabia.

Crude oil reserves are subject to continuous revision as exploration proceeds. For example, Brazil's reserves have recently been raised from 7.5 to over 13 billion barrels (*Oil & Gas Journal*, 2 December 2013) and higher estimates have been published. Pre-salt, deep, offshore reserves in Brazil could potentially quadruple the figures from current official estimates.

According to Dr Edgar Rangel-German (*The New Role of the Mexican Upstream Regulator*, XXIII La Jolla Energy Conference, May 2014) CNH, the Mexican independent energy regulator, is now reporting that the nation's 2P crude reserves exceed 26 billion barrels, a substantial increase over earlier estimates. (A common definition of 2P reserves is: those reserves which analysis of geologic and engineering data suggests are more likely than not to be recoverable under reasonable economic, technical, and operating conditions.)

Looking ahead

Much of the poor production performance seen throughout Latin America can be tied to the failure to follow through with the reform programmes implemented in the 1990s. Soon after the 1990 reforms, upstream oil and gas investment began to flow to the region, only to see a return to resource nationalism in the 2000s, this time with a particularly virulent strain. This retrenchment in reform followed the run-up in world oil prices – an often-positive environment for resource nationalism. The subsequent policy shifts were highly visible in Argentina, Ecuador, and Venezuela and in the gas sector in Bolivia. The surge in resource nationalism took several forms, ranging from outright expropriation to implementation of new requirements that discouraged foreign investment and participation in the petroleum sector.

There are now some positive signs that genuine reform is back on the table and we cannot discount the catalyst of lower oil prices and declining government fiscal outlooks as an instrument which is sustaining reform efforts. None of the new reform programmes come with guarantees, but Brazil (even with some recent setbacks) and Colombia have shown that genuine benefits can be achieved. The Mexican initiative is wide-ranging and serious. Venezuela will likely require a regime change before major reforms can be implemented, but given conditions in the Bolivar Republic this may occur sooner rather than later.

'THERE ARE NOW SOME POSITIVE SIGNS THAT GENUINE REFORM IS BACK ON THE TABLE …'

So what might a sustained petroleum reform programme yield throughout Latin America in terms of rising oil production? Recent experiences with production growth in the USA and Canada can at least provide a technical guidepost on the potential pace of development, in circumstances in which capital is deployed in a timely manner. Of course, whether such reforms are likely, and can be sustained for long enough to make a difference in sustained production growth, is an entirely different question.

Mexico

The historical setting that created Petróleos Mexicanos (PEMEX) cannot be ignored in any assessment of the Mexican initiative to proceed with massive reform of its energy complex. The Great Depression, low oil prices leading to declining payments to the Mexican government, and the view that foreigners were taking advantage of Mexican workers led to strikes and political turmoil. On 18 March 1938 the Mexican Supreme Court approved an expropriation of all subsoil assets.

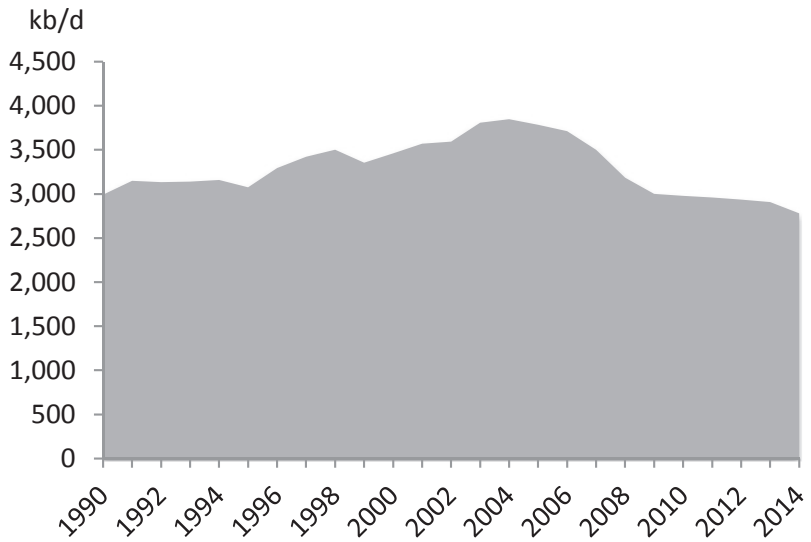
PEMEX is the oldest of the major national oil companies (NOCs); for many years it has been the largest

supplier of crude oil to the USA, an instrument of pride for the Mexican people and a major revenue source for the government. However, the North American petroleum renaissance has not only provided a demonstration that mature petroleum provinces can be rehabilitated, but that Mexico was entering a more competitive environment and US interest in PEMEX crude was fading quickly in light of rising US and Canadian production. Indeed, one of the positive forces for reform was that Mexican crude was no longer 'required' in the USA. The implementation of constitutional changes and of novel legislation used to open up the Mexican petroleum sector were politically difficult tasks. Opposition to the reforms took many shapes, with some political opponents complaining that increased Mexican oil production 'would only end up being exported to the Americans'. Presumably the opponents of reform were not impressed by the fact that the crude exports would receive world oil prices.

After an era of declining crude production (see graph below), particularly in contrast to the US experience, a political consensus came together that the single operator, PEMEX, could no longer efficiently manage such a wide variety of challenges. So for the first time in Mexican history, a wide range of foreign participation is now possible in the petroleum sector.

Anyone who has experienced a presentation by Dr Edgar Rangel-German, head of the Mexican energy regulator (CNH), cannot help but be impressed by the comprehensive nature of the reforms. CNH will undertake management of the bidding process, sign, manage and oversee contracts and drilling programmes, provide expert opinion on exploration and development plans, and authorize seismic studies, in addition to carrying out other important functions. Participation can take the form of joint ventures, to outright bid and development of a play acquired through a competitive auction by a foreign company. Data rooms will be opened up for the new prospects and extensive efforts will be implemented to encourage foreign participation.

Even with the implementation of reforms, PEMEX will continue to have an important role, and considerable resources remain under its control. PEMEX has ended up with 83 per cent of current 2P reserves, but will only receive around 20 per cent of prospective reserves and less than 10 per cent of unconventional reserves. Permitting a strong role for PEMEX is critical for the success of the reform programme, while at the same time an explicit admission that there are plenty of reserves available for participation by foreign or private Mexican companies – for which PEMEX may lack the resources and/or technical capacity to undertake at this time.



Mexican oil production, thousand barrels per day (kb/d)

Source: EIA

Argentina

The US EIA has reported that, other than the USA, Argentina is likely to have the biggest potential to develop shale oil in the western hemisphere. The EIA has reported technically recoverable shale reserves at 27 billion barrels and this estimate is likely to be revised upward once additional exploration takes place. To date, most exploration has taken place in the Los Molles and Vaca Muerta formations, where 50 wells have been tested with largely positive results. Initial production rates have been from 180 to 600 b/d, not substantially out of line with the experience in many of the US shale formations.

Long-standing investment risks, such as price controls and export taxes, are the biggest constraint to sustained petroleum growth in Argentina. In addition, the ongoing legal battles in US courts from the default finding on official debt are contributing to reluctance for full-scale investment.

Venezuela

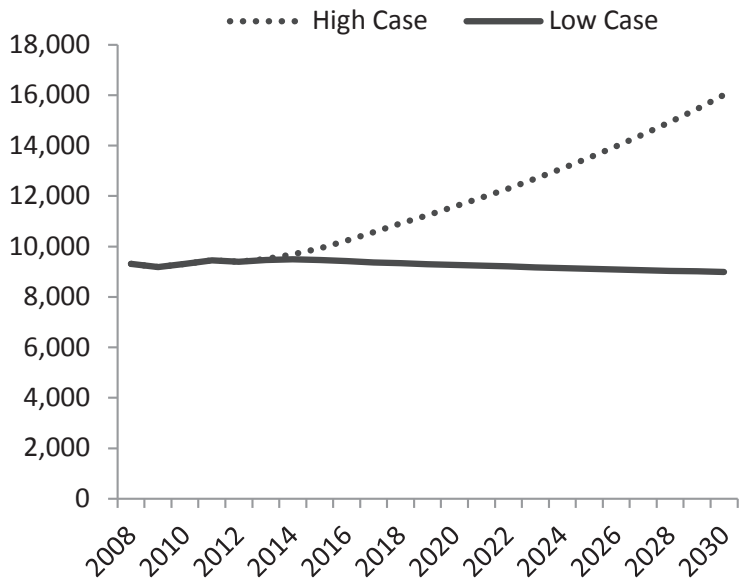
In the 1970s, Venezuela nationalized its petroleum industry and created a state company, Petróleos de Venezuela S.A. (PDVSA). Although PDVSA had many of the problems common to

state-run companies, it was considered a highly professional and competent organization until 2002, when half the employees walked off the job in reaction to policies implemented by then-President Chávez. Most of the liberalization programmes put into place in the 1990s were discontinued, and there were substantial increases in tax and royalty rates.

The large-scale nationalization of foreign investor holdings in 2006 was especially damaging, as the government mandated the renegotiation of a 60 per cent minimum PDVSA share in project operations. Sixteen firms, including Chevron, ExxonMobil, and Royal Dutch Shell, complied with new agreements, while Total and Eni were forcibly taken over. After Chávez's death in 2013, President Maduro continued Chávez's policies. Venezuela is also increasing pressure on the foreign operators that remain in the country to increase investment to offset recent production declines. Court battles continue over compensation from the nationalization programme and Venezuela is facing about 20 cases at the World Bank tribunal; these are likely to see resolution sometime before the end of 2014.

Latin America's production uncertainty

From a strictly technical view, Latin America's major petroleum producing provinces could substantially raise production over current levels.



Latin America uncertainty range, thousand barrels per day (kb/d)

Sources: Historical figures, EIA. Forecast range estimated from EPRINC calculations on the pace of petroleum development under alternative reform scenarios. EPRINC combined totals are for Argentina, Brazil, Colombia, Mexico, and Venezuela.

Experience in the USA and Canada demonstrates that improved extraction techniques, sound application of new production technologies, and sustained investment coupled with stable contract terms and contained political risk would probably yield continued production growth, given the existing and likely growing reserve base in Latin America. The uncertainty will remain largely above the ground.

'… LATIN AMERICA'S MAJOR PETROLEUM PRODUCING PROVINCES COULD SUBSTANTIALLY RAISE PRODUCTION OVER CURRENT LEVELS.'

The range of uncertainty in Latin American production is shown in the graph above. Approximately half of the uncertainty comes from Brazil, given the large potential for the pre-salt and its requirement for large-scale investment. Most of the remainder will come from Mexico and Argentina. Venezuela offers considerable potential, but this potential cannot be realized through modest reforms and will likely require regime change.

Special thanks to Desmond Dahlberg of EPRINC for valuable comments and reviews, and Ivan Sandrea from Sierra Oil & Gas S. de R.L. de C.V. in Mexico.

Natural gas in Latin America and interactions with the rest of the world

Anouk Honoré

Latin America has long been disconnected from other gas markets, focusing instead on regional integration via pipeline – especially in the Southern Cone. In the mid-2000s, a shortage of natural gas production coupled with political disagreements, tensions over price renegotiations, and shortfalls of deliveries from neighbours led several countries to turn to LNG imports – either to replace or supplement indigenous production and imports of pipeline gas. From 2009, the region has gone from being a closed regional market, with only regional pipeline

flows, to a region that both imports and exports LNG. *(In this article, Latin America includes 10 countries: Argentina, Bolivia, Brazil, Chile, Colombia, Ecuador, Paraguay, Peru, Uruguay and Venezuela.)*

'LATIN AMERICA HAS LONG BEEN DISCONNECTED FROM OTHER GAS MARKETS …'

Current and projected gas demand

In 2013, Latin America produced 134 bcm of natural gas. About 17 bcm were exported by pipeline from Bolivia to Brazil and to Argentina, and from Colombia to Venezuela, while about 15.5 bcm of LNG were delivered to Argentina (6.3 bcm), Brazil (5.4 bcm), and Chile (3.8 bcm). LNG deliveries to Latin America represented less than 5 per cent of the total volume traded, but they are rising rapidly to meet growing gas demand (+7.3 per cent since 2010 and +60 per cent since 2000). With the necessity of not letting the lights go out, gas consumption is expected to continue to grow at a sustained pace in this decade and the next. While the energy mix differs from country to country, power generation from gas is rising at the regional level in order to diversify away from oil and coal plants and to back up hydropower – which has been causing severe problems especially in Brazil, where dry weather has depleted hydroelectric reservoirs several times since the severe drought of 2001. The challenge for national governments will be to find a balance of sources that best provides energy security, meets growing demand, and remains environmentally sustainable but which can also be developed at a competitive cost. LNG is seen as an option to ensure that the right balance of gas is used for power, but LNG imports have proved to be very expensive for the importing markets. The pricing structure of gas flows is complicated: Bolivian and Colombian pipeline exports are oil-indexed, Argentine pipeline exports seem to be cost-related, spot LNG imports into Brazil and Argentina have been based on the highest alternative market price plus a freight differential plus a trading margin, while long-term Chilean LNG import contracts have been based on Henry Hub gas prices since January 2012. Despite the great flexibility of LNG in meeting seasonal needs, with low (subsidized) national prices, some countries are struggling to pay for their imports and have again been turning their attention to developing their indigenous resources instead.

Domestic production and LNG imports

On paper, the region has enough reserves to fulfil its needs, but lack of upstream investment and politically motivated export and import policies complicate the situation. Countries in Latin America vary greatly in the way they develop their gas resources. All markets are open to outside investment, to varying degrees, but not all offer competitive terms and confidence to investors. Natural gas production is undermined by a number of geopolitical uncertainties, along with economic, environmental, social, and regulatory issues. This situation has impacted both the pace and the expectations for future production in most countries.

'COUNTRIES IN LATIN AMERICA VARY GREATLY IN THE WAY THEY DEVELOP THEIR GAS RESOURCES.'

Brazil has three LNG regasification terminals. After the severe drought-induced power crisis in 2001, thermal stations were developed to compensate for hydroelectric plants, which accounted about 90 per cent of electricity generation. In the late 2000s, state-controlled Petrobras turned to LNG to complement pipeline gas from Bolivia in an effort to increase natural gas supplies and security. The lack of a countrywide national transmission system (networks are located mainly in the south-east and the north-east regions) adds additional value to importing LNG. After having relied primarily on the spot market, Petrobras signed short-term LNG supply contracts in response to rising demand; this has limited demand for spot LNG cargoes despite low hydropower production in 2013/14. Brazil is planning to add a fourth LNG terminal, while at the same time looking to boost its indigenous production. Recent discoveries by Petrobras in north-eastern ultra-deepwater are putting the spotlight back on the country's post-salt potential, but high operating costs and complex legal issues have been dampening some of the initial euphoria regarding the pre-salt basins. The company expects to have more than enough gas supplies to meet projected demand in about a decade, but without specifying how much associated gas will come from offshore sub-salt deposits.

Argentina has two LNG regasification terminals. The country has substantial gas reserves but the Emergency Law of December 2001 (which followed political and economic crisis) resulted in a fall in gas prices that were subsequently frozen by the government. This led to a significant reduction in new investments in the gas sector, while at the same time generating an increase in the industrial and power demand for gas. The decline in gas production in the second half of the 2000s, together with fast-growing demand, led the country to restart imports from Bolivia in 2004, and later to turn to LNG to supplement the imports. Argentina moved from being a net gas exporter to a net importer – as a result of political choices rather than geological constraints. The US EIA

recently ranked the country in second place for potential shale gas resources. These discoveries raised expectations of increased indigenous output, even if the situation was complicated in April 2012 by the nationalization of the country's biggest energy company, YPF SA, and by the revocation of oil and gas concessions, notably in the shale provinces. The government has been trying to reverse years of declining output and cut back expensive gas imports by hiking state-controlled prices to stimulate investment in exploration and production. It expects that by 2020 the production of shale gas will be sufficient to replace imports of gas, but this is very uncertain.

Uruguay will open its first LNG regasification terminal in 2015. As Uruguay has a small gas market compared with its neighbours it has been in talks with Argentina, which is considering the possibility of receiving part of this LNG through a reversal of an existing gas pipeline. Uruguay is also open to reloading LNG for the fast-growing Brazilian market. Whether re-export by pipeline or LNG reloading sales to neighbouring countries, these options will represent a new stage of energy integration in the region.

The Argentine gas crisis had an impact on **Chile**, which had long been dependent on pipeline gas from its neighbour. Argentine exports started to have a problematic record of reliability following the 2004 gas crisis – when authorizations for new export permits were suspended and national consumption was given priority. Chile turned to LNG following repeated interruptions and consequent economic problems for industry and electricity generators, which had to resort to more expensive alternative fuels. LNG imports through its two regasification terminals have enabled natural gas to recover market share lost to diesel oil and other fuels in power generation. The country is also looking at boosting its gas output, but LNG imports are expected to surge in the 2010s as copper mining projects expand in northern Chile and new gas-fired generation capacity comes on line.

The major source of supply for the Southern Cone has long been **Bolivia**, which is still the largest gas exporter on the continent (17 bcm by pipeline to Brazil and Argentina in 2013). The country was supposed to become a natural gas hub in the 1990s but it lost its position of major gas supplier in the second half of the 2000s due to the lack of upstream investment resulting from the 1 May 2006 nationalization. The nationalizations of the oil and gas industries and the revision of contracts with multinational companies were important objectives of the newly elected President Evo Morales. In the following years, Bolivia's proven reserves dropped considerably (from 740 bcm in 2005 to 281 bcm in 2013), suggesting possible problems in sustaining future rates of production and export commitments. The country has a long-term contract with Brazil (until 2019) and Argentina (until 2026) and it was hoping to start exporting to Uruguay and Paraguay, but this would require the construction of new pipeline(s) and/or the use of Argentine pipelines for transit. In the 2000s, the country also had ambitions to export part of its production in the form of LNG, but being a landlocked country it would have needed access to the sea through either Peru or Chile. The project via Chile was economically the best but was politically complicated (relations between the two countries have been problematic since the nineteenth century war that saw Bolivia lose its access to the sea to Chile). Both options were finally abandoned due to the high cost of the project and political turbulence in Bolivia.

Peru also has a considerable gas surplus, but the country chose the LNG option rather than pipeline exports to neighbouring markets. Peru LNG started operations in June 2010 and most of the LNG was expected to be shipped to Mexico. It is interesting to note that the LNG was not sold to Chile, which had been constructing an LNG import terminal in parallel; this created a sub-optimum supply position for both countries and was a result of political tensions.

Colombia produced about as much gas as Peru in 2013 and is the third (and final) country with some gas surplus, which has been exported by pipeline to Venezuela. However, declining natural gas reserves combined with the effects of climate change could make it a net importer in two years. In addition to looking at unconventional gas exploration (coal- and shale-related deposits), Colombia is examining the possibility of constructing a regasification terminal. Because the country is short of gas during El Niño, but potentially in surplus at other times, Colombia is also considering a liquefaction plant, which could make it a potential LNG supplier for small cargos to neighbouring countries.

Venezuela has also been examining the possibility of LNG exports with different international oil companies since the 1980s but has made little progress, changing its policy on LNG exports several times. The country holds the largest gas reserves in Latin America, and is the second producer behind Argentina, but is a net importer of gas. It is believed that offshore gas projects will focus on feeding growing local demand for natural gas, rather than creating LNG for the export market.

Finally, **Ecuador**, a small gas market, announced plans to build an LNG regasification terminal to supply thermoelectric plants that (currently) run on diesel.

'WITH A FAST-RISING GAS DEMAND OUTPACING INDIGENOUS PRODUCTION, THE REGION IS ON TRACK TO BECOME A SIZEABLE IMPORTER OF LNG.'

Expectation of LNG imports

It may well be that political decisions, more than economic logic, have shaped gas developments in Latin America. With a fast-rising gas demand outpacing indigenous production, the region is on track to become a sizeable importer of LNG, even if its relative share may not exceed about 10 per cent of the global trade by 2020. The counter-cyclical seasonality of Argentina and Brazil with the northern hemisphere also offers interesting arbitration opportunities for LNG sellers who, in a tight market, have charged prices as high as those paid by Asian buyers. Post 2020, having tasted this diversification option, it is unlikely that LNG imports will disappear. However, if plans for domestic production succeed, LNG may return to being a marginal source of supply; the growing interactions of Latin America with the global gas market may therefore be just a passing phase.

Kick-starting the shale boom in Argentina? The new reforms in context

David R. Mares

Introduction

This fall the Argentine government passed a new hydrocarbons bill with the intent of attracting foreign direct investment in its energy sector, particularly in shale oil and shale gas areas. With 802 trillion cubic feet (tcf) of technically recoverable gas, Argentina has the second-largest shale gas reserves behind China. It also has the fourth-largest shale oil reserves (27 billion technically recoverable barrels), as well as a developed domestic gas market and export infrastructure. The country is thus a potentially important player in the global oil and gas markets. Not only has the country been a major supplier of natural gas to neighbouring Chile, Uruguay, Brazil, and Bolivia in the past, but its domestic use is so large that it has become an important importer of natural gas via pipeline from Bolivia and it has built two LNG import facilities. The World Gas Model at Rice University indicates that Argentina could supply LNG to China by 2030. A number of companies (such as Repsol/YPF before its nationalization in April 2012, Total, Apache, Exxon, Shell, Pan American Energy, and Americas Petrogas) have already begun exploring, with Repsol/YPF making a significant discovery in December 2011.

'ARGENTINA HAS THE SECOND-LARGEST SHALE GAS RESERVES BEHIND CHINA.'

Nevertheless, until significant exploration is undertaken one cannot know how much shale gas exists and is potentially recoverable under current economic and technological conditions. In the USA, where shale gas exploration and production has been underway for a number of years, dramatic recalculations of reserves downward have occurred. For example in 2012 the EIA reduced the estimated national shale gas reserves from 827 tcf to 482 tcf, which included a reduction by 66 per cent of the prolific Marcellus Shale basin; two years later, it downgraded a potentially major basin in California (Monterey) by 96 per cent. The liquids potential of Argentine shale gas will be a key factor for investors, but preliminary estimates indicate that only 20 per cent of the most important basin, Vaca Muerta, has liquids. Clearly, a great deal of exploration needs to occur to confirm Argentina's potential. And estimates for full development reach US$250 billion. Investment in the logistics and infrastructure, including refining, to support the expected levels of production will also be significant. But Argentina has had a troubled relationship with foreign investors, even beyond its historic sovereign debt default in 2002 and the renationalization of YPF in 2012. Domestic price controls, export controls, broken contracts, and incentive programmes that failed to materialize have all contributed to Argentina's current energy crisis.

'… A GREAT DEAL OF EXPLORATION NEEDS TO OCCUR TO CONFIRM ARGENTINA'S POTENTIAL.'

The government of President Cristina Fernández de Kirchner (CFK) expects the optimists to flock to Argentina enticed by the geological fundamentals. Stimulated by a successful negotiation of over US$1 billion with Chevron in the summer of 2013, the government developed a new hydrocarbons law that promises significant incentives to attract the investment that will reproduce the US shale boom in Argentina. One just needs to get past the broken promises of the past.

Current investment environment in Argentine hydrocarbons

The belief that oil and gas are 'a basic resource for economic growth and the development of the country' is widespread and not unique to the party supporting the CFK government. For example, the Senate supported nationalizing YPF 63:3, with 4 abstentions and the House voted 207:32, with 18 abstaining.
The nationalization left 49 per cent of YPF shares in non-Argentine government hands, but because the Act declares that it is in the public interest for the country to achieve self-sufficiency, the legislation sets a context and a mechanism for direct state control over the company and the sector. The government has been quite willing to use those levers to pressure and discipline companies that fail to explore or produce at rates expected by the government.

Federal Decree 929 in 2013 attempted to stimulate incentives for both conventional and unconventional hydrocarbon production by raising the domestic price of oil and gas, permitting repatriation of some profits after certain levels of investment and production, and offering a price of US$7.50/MMBtu for new gas supplies. The CFK government appears to be following through on its March 2014 announcement that domestic gas prices would rise significantly this year in a series of monthly increases. But similar Gas Plus and Oil Plus programmes of the recent past failed to have staying power. With inflation over 30 per cent, falling international reserves, and elections next year the commitment of the government to these incentives remains an open question.

Though the first shale hydrocarbon discoveries date from the end of 2010, the current rate of shale exploration is approximately similar to that in 2012, after a decrease in 2013 as companies reacted to the uncertainty introduced by the nationalization of Repsol/YPF. The NOC holds most of the shale acreage that has been licensed to date, 75 per cent of wells drilled in Vaca Muerta, 90 per cent of the shale oil produced to date, and 80 per cent of the shale gas. Until auctions for new acreage begin, new investors are limited to partnering with YPF or farming-in to the few existing independent projects.

Chevron is the biggest player in Argentine shale after YPF, with almost US$3 billion invested in 2013–14. Shell Argentina's subsidiary, O&G Developments, announced that it will invest US$500 million in unconventional drilling in 2014, up from US$170 million in 2013. Exxon Mobil drilled five wells in 2013 and is currently exploring in six blocks in Neuquén. Total had been the largest gas producer in Argentina until YPF purchased Apache's assets. In shale, Total had 13 exploratory oil wells operating in 2013 (seven in Vaca Muerta) and plans to drill another 12 in 2014; the company partners with Shell in the Rincón de la Ceniza block. Total will also operate its first unconventional gas project in Aguada Pichana this year. Gazprom has had discussions with YPF and will be sending technical teams to evaluate Vaca Muerta sites.

The extent to which these investments were driven by commercial calculations is not clear. Federal government policy restricts currency outflows, meaning that companies (such as Chevron, Dow, Wintershall, Exxon, and Madalena) with profits in the country cannot convert their pesos into dollars and take them out of Argentina. Inflation is running at about 35 per cent and in the recent past the government has seized bank accounts, pensions, and private companies, and has also renegotiated government bonds at a fraction of their original value (this does not refer to the current 'technical default' on its foreign debt). Consequently, a company would prefer not to keep their Argentine pesos in cash or buy government debt in pesos, which makes investing their Argentine profits in Argentina an attractive, if not ideal, option. Dow Chemical's Argentine subsidiary has a gas-starved petrochemical joint venture in Argentina, associated with YPF to develop the El Orejano block. Once developed, Dow gets a 50 per cent share of the project (though it puts in two-thirds of the investment) or its US$120 million becomes a five year loan (no terms of loan disclosed). Gazprom's interest in Argentine shale may be Vladimir Putin's compensation for Argentina's willingness to buck the international sanctions the USA and the EU are imposing on Russia for its behaviour in the Ukraine crisis. (Argentina has announced that it will sell agricultural products to Russia to replace lost imports.)

The new hydrocarbons legislation

The new hydrocarbons legislation replaces a law that everyone believes is outdated, but the terms of the new legislation have been controversial. The hydrocarbon-producing provincial governments opposed efforts by the Federal government to establish national criteria that limited provincial discretion in capturing the rents in favour of new federal efforts. Though a deal was reached with the provinces and the legislation passed in the Senate, it was opposed by all the opposition parties, who stipulated that were they to win the Presidential and legislative elections next year, they would change the law.

The new legislation offers significant incentives for investors. Provinces must now follow a standard contract in licensing exploration and production of provincial-owned hydrocarbons, which limits tax and royalty rates. The reform eliminates the future establishment of

areas reserved for state companies and establishes a mechanism to eliminate ENARSA from joint ventures in offshore. YPF is consequently strengthened, since provincial oil companies are no longer able to participate in joint ventures without putting up investment capital and ENARSA is effectively disestablished as a producer. Limitations on exploration permits have been modified; a company may now have an unlimited number of exploration permits, while the area retained for future exploration has been increased for both conventionals and unconventionals as long as an unspecified 'good faith' effort has been made to move to production.

Production permits may now be extended for an unlimited time and restrictions on the number of them a party may hold have been eliminated. Initial permits are: 25 years for conventionals, 30 for unconventionals, and 35 for offshore (unconventionals and offshore are increased). Permits can be renewed indefinitely in 10 year extensions – previously this was only possible once. Extensions will entail payment of bonuses. Royalties are set at 12 per cent, but provinces can charge an additional 3 per cent for extensions up to a maximum of 18 per cent and can discount down to a minimum of 5 per cent royalty for permits that have migrated from conventional to unconventional, for secondary recovery operations, and for extra-heavy oil. Tariffs on imports of necessary inputs have been eliminated or reduced. With a minimum investment of US$250 million (down from US$1 billion) up to 20 per cent of conventional or unconventional oil or gas production can be exported; for offshore the volume is up to 60 per cent of production. Companies are also guaranteed free use of the foreign exchange received for exports.

On paper the reform offers significant incentives for investing in Argentina's oil and gas. But it does not address key issues that have provided disincentives for investors: domestic prices, export taxes, repatriation of profits, and domestic content requirements. One can also expect that royalty rates will rise once production is well under way. Even Colombia, with a reputation for being market-friendly, varies royalties by the size of fields and has a maximum rate of 25 per cent, not 18 per cent. It will be politically impossible for any Argentine government to stick to 18 per cent royalties as production rises.

'ON PAPER THE REFORM OFFERS SIGNIFICANT INCENTIVES FOR INVESTING IN ARGENTINA'S OIL AND GAS.'

Conclusions

It is difficult to understand the current state of development in Argentina's oil and gas sector. Current investments cannot be taken as indications that the shale boom is beginning in the country. Government policy is presently favourable for investment, but lacks credibility. The lack of credibility of any government policy in Argentina, no matter the government, contributes to an evolving governance structure that pushes investors to focus on operations that can produce the highest returns in the shortest period. The signing of an agreement is no guarantee that it will be developed to its full potential. Argentine federal and provincial governments have developed tools to seize investments that do not perform to their expectations and they have used them against private companies as well as against other nations' NOCs. Even while attempting to attract investment to the shale basins, and while the new hydrocarbon legislation was being negotiated with the provincial governments, the CFK government still thought it was reasonable to threaten Shell over its alleged engagement in a 'conspiracy' against the Argentine peso. The government's call for provinces to investigate Shell's licences – for not investing sufficiently in developing those resources – illustrates its willingness to strike out in whatever way possible against those who do not follow government preferences.

In the short term, it seems that the drivers of investment will be the speed with which returns can be achieved, rather than the long-term promises of government. Since shale well life-cycles produce high returns up front and decline rapidly, we can expect to see some investment in non-conventionals, but less in conventionals and offshore. The upside for the industry could be that the non-commercially stimulated investments of today can reveal more of the country's shale potential. Once the hydrocarbon reforms are implemented, that knowledge could help stimulate greater interest in Argentine shale.

'CURRENT INVESTMENTS CANNOT BE TAKEN AS INDICATIONS THAT THE SHALE BOOM IS BEGINNING IN THE COUNTRY.'

Although this government strategy can stimulate drilling and reveal information about reserves in the short term, its very success reinforces the perceptions of both Argentine politicians and the public that government can be successful in setting the terms and demanding high rent appropriation. The traditional Argentine model of unilateral government control has produced booms in the recent past, but they were unsustainable both economically and politically. Thus, although companies may be waiting for the presidential election in 2015 in hopes of more market-friendly policies, whoever wins is unlikely to alter the country's dependence on unilateral public policy that adjusts easily to the ever-changing winds of Argentine politics.

Colombia's early steps to becoming a regional energy hub

Armando Zamora and Hernán Martínez

Colombia has traditionally been a leading advocate of economic and political integration in Latin America, even as it struggles internally with a civil conflict that has brought grief to its population over the last half century. The country has been proactive in the creation of all the regional economic integration bodies, including the Latin American Energy Organization, OLADE – one of the economic integration bodies that Colombia has supported and used as a lever to promote the energy integration of the continent, and its own role in the process.

Notwithstanding its complex geography, which has made it difficult to develop a modern road transport infrastructure, the energy sector has been able to integrate the country with an efficient network for electricity and gas transmission and distribution, and has maintained a working electricity interconnection with Ecuador and Venezuela. The electricity and gas production and distribution networks have evolved within a regulated environment that is open to private investment, coexisting with a relatively balanced presence of the State in all stages of the value chain.

Colombia's vocation as a regional energy integration hub comes naturally from its geographical location and its rich endowment of energy resources. The country has one of the world's largest untapped potentials for hydroelectricity, the largest coal resources in Latin America, a sizeable potential for oil and gas production, and a well-run and well-regulated combination of electricity, gas, and petroleum markets. Given its geographical location (with multiple frontiers between energy-rich and energy-poor countries) it is a potential transit route for Venezuelan hydrocarbons to other countries in the region, the Pacific Ocean, and the Asian markets. It also benefits from a well-established positive attitude towards political and economic integration.

'COLOMBIA'S VOCATION AS A REGIONAL ENERGY HUB COMES NATURALLY FROM ITS GEOGRAPHICAL LOCATION AND ITS RICH ENDOWMENT OF ENERGY RESOURCES.'

In fact, the country has led many energy integration initiatives, not only through the various political bodies of the region (CEPAL, OAS, OLADE, CARICOM, among others) but also involving some minor but strategic interconnections across the borders with Brazil, Ecuador, and Venezuela. It has also been involved in some more ambitious regional projects – such as the electric interconnection with Central America, a submarine cable to Dominica, an oil pipeline connecting Venezuela with the Pacific Ocean, a private-led regional gas market initiative for Central America and the Caribbean islands, and a gas pipeline from Venezuela to Central America. Some of these projects have matured at different speeds and materialized to various degrees, while others remain beyond commercial grasp at present.

A closer look beyond political integration initiatives towards specific regional integration projects, their justification, status, and challenges, may shed some light on the issues that are preventing deeper energy integration in the region, and highlight the conditions that could facilitate the process in the future. To this end, a number of key initiatives merit attention in the areas of: electricity interconnections and bulk sales; gas pipelines and gas supply agreements; transnational crude oil pipelines; and the corporate presence of Colombian energy companies in the region.

Electricity interconnections and trade

Colombia's privileged position in the promotion of electricity integration with its neighbours stems from a combination of geography, endowment, policy, and managerial capacity. According to the World Energy Council's website, Colombia has an estimated hydroelectric potential of 1000 TWh/yr, of which around 20 per cent (200 TWh/yr) are estimated to be technically feasible. Current installed generation capacity is 9.3 MW, generating 46,000 GWh in 2012, about a quarter of the technical potential, according to the Mining and Energy Planning Unit of the Ministry of Mines and Energy (Plan de Expansión de Referencia, Generación – Transmisión, 2013–2014), and 64 per cent of total capacity.

After an energy crisis led to rationing back in 1992, the electricity industry was privatized and regulated, with special focus on generation and distribution. The national grid company ISA was partially privatized and became a model state company with a diversity of assets in Argentina, Bolivia, Brazil, Central America, Chile, Ecuador, and Peru. Local generation companies have also diversified regionally, most notably the regional State Company EPM from the Antioquia department.

The Central American interconnection project

An ambitious plan to connect the Colombian grid system to the Central

American Interconnection System, SIEPAC, involving six countries in the region from Panama to Guatemala, with a future proposed interconnection with Mexico, has been promoted by the Colombian government with the backing of the national electricity grid company, ISA, and the electricity and gas regulator, CREG, among other public and private organizations. ISA has been a shareholder of the company that owns SIEPAC since 2005, with 11.1 per cent of ownership. Notwithstanding the complexities of the project, not just from a political perspective but also from the multiple regulatory systems involved, Colombia has persevered in its commitment. The most formidable obstacle to this project has been Panama's reluctance to allow the construction of high-voltage transmission lines across the Darien rainforest. Not only have environmental concerns been argued, but also, and less publicly, the widespread fear of opening a spillover gap for Colombian violence or drug trafficking.

Submarine electricity transmission cable to the Dominican Republic and Puerto Rico

In 2008, a joint examination of energy supply alternatives to the Dominican Republic and Puerto Rico included oil products, gas, coal and interestingly enough, the direct supply of electricity through a submarine cable with a transmission capacity of 1 GW. This idea stems from the relatively short distance (slightly more than 600 km) between the northernmost tip of Colombia's continental territory and the island of Dominica. With proven technology at hand, such an option would be competitive with other alternatives. The project has not yet reached the feasibility stage, but has raised the profile of Colombia as a hub for integration of the region with the Caribbean islands.

Gas pipelines and supply

The current gas reserves of Colombia (approaching 8 trillion cubic feet, tcf) and its geological potential have raised the prospect of opening the international markets beyond the supply of local needs, considering that the domestic market has reached a state of relative maturity. A policy of restrictions to gas exports was lifted in 2010 to open the international markets to domestic gas; this offered increased incentives to the development of additional reserves and, particularly, to risky investments in new exploration.

'THE CURRENT GAS RESERVES OF COLOMBIA AND ITS GEOLOGICAL POTENTIAL HAVE RAISED THE PROSPECT OF OPENING THE INTERNATIONAL MARKETS …'

Gas interconnections and seaborne projects

In 1973 Chevron discovered the giant fields of Ballena-Chuchupa in the north-eastern department of Guajira in the Colombian Caribbean coast, with an estimated 5 tcf of original gas in place. Those resources did not have a ready market at the time and the government, Ecopetrol, and Chevron (the field operator) promoted an ambitious initiative to develop a market for that gas. The first stage was a massive development of the domestic market. The field has been contributing about 80 per cent of Colombia's domestic needs – in 2014, after 30 years of production, this is in the order of 900 million cubic feet per day (mcf/day). In the early 1990s another giant system of gas was discovered, in central Colombia at Cusiana and Cupiagua, with more than 7 tcf of estimated total reserves. These two fields represent more than 90 per cent of the total reserves discovered.

In October 2007 a gas pipeline connecting the Guajira fields with Maracaibo in western Venezuela was inaugurated. The pipeline was built by PDVSA Gas, as it was in Venezuela's interest to use as much gas as Colombia could provide, in order to enhance their oil production in the region. Under a bi-national agreement, Colombia would export approximately 100 million cubic feet per day on average until 2011, at which time the pipeline flow would be reversed and the vast reserves of gas in eastern Venezuela, estimated at 195 trillion cubic feet, would be made available to Colombia. In 2011 Colombia agreed to continue supplying gas indefinitely, as Venezuelan gas has been slow to gain access to the country's western provinces, due to continued delays in the construction of the necessary transmission infrastructure. Despite some intense political tensions between the two governments, at no time has the Colombian government suggested a suspension of gas supply, even when President Chávez ordered the mobilization of troops to the Colombian border in March 2008.

Earlier on in 2000, and just before its collapse, Enron was close to obtaining government approval for a project to build a gas pipeline from the Guajira fields to Panama. However, a political battle within Colombia (between Congress and the Minister of Mines and Energy) at the time, and the subsequent collapse of Enron, prevented the materialization of the project.

Small-scale seaborne LNG

In 2013 a new era of small-scale seaborne LNG commerce was inaugurated following approval of the construction of an export liquefaction terminal at Coveñas and an import regasification terminal in Cartagena,

with capacities of 100 mcf/day and 400 mcf/day respectively.

The rationale behind these apparently contradictory simultaneous export and import projects is that the opening of exports would optimize the production profile of existing fields and encourage new exploration and development activities, while the construction of the import facility would provide a reliable source of fuel to the thermal plants in the north in case of seasonal shortages (due to low rainfall or, in future, by the gradual exhaustion of the currently producing fields). On the market side, the growing need for alternatives to Venezuelan heavy fuels (which come at a high political cost) as energy sources in Central America and the Caribbean would get a boost if a ready source of cleaner and less expensive gas at a small scale was present in the region. In the meantime, the growth in demand in Asia, following the Fukushima events, has given rise to attractive prices that have supported a multiyear purchase agreement to back the financing of the export facility.

Crude oil pipelines

Colombia and its crude-producing neighbours have traditionally relied on their own crude transport infrastructures to ship crude oil to their traditional markets, but a number of factors – recent geopolitical shifts in demand and supply, internal security problems in Colombia that have affected crude oil transport pipelines, and even pragmatic reasons of trading economics – have justified some strategic cooperation projects to transport crudes across borders:

Pipeline from Venezuela to the Pacific

A long-held desire of the Venezuelan government – to build a pipeline across Colombia to the Pacific Ocean to gain access to the Asian markets – is gradually becoming feasible. Following an initiative by the Colombian National Hydrocarbons Agency (ANH) a Canadian hydrocarbons transport company, Enbridge, undertook the promotion of a 760 km pipeline from the Colombian Eastern Llanos region to the port of Buenaventura on the Pacific. The project has attracted the attention of Ecopetrol together with that of other significant producers involved in this area; these bodies have acquired shares in OAP, the project promotion vehicle (the name OAP relates to the company's acronym in Spanish). The first pre-feasibility studies have produced encouraging results as the pipeline would be a state-of-the-art design to transport, initially, 250,000 barrels per day of heavy crudes that are increasingly being produced in the area; it would easily accommodate Venezuelan heavy oils.

As the OAP project continues to make progress, the pipeline transport of Venezuelan crudes to the Pacific moves closer to becoming a reality, as a substantial existing pipeline that runs from the central producing region of Colombia to the Caribbean Sea (parallel to the Venezuelan border) could readily reverse its flow midway, from the Arauca Region to connect with the OAP at its start.

Ecuadorian pipeline connection

Two pipelines run to the Pacific Ocean along the Putumayo River, one on each side of the border between Ecuador and Colombia. Both pipelines transport crude to the ports of Esmeraldas and Tumaco respectively. With Colombia's production in the region outstripping the transport capacity of its Trans Andean pipeline and Ecuador's heavy oil transport pipeline (OCP) having excess capacity from just across the Colombian border, a project to build a transnational interconnection (with an initial capacity of 20 kb/d and an estimated 200 kb/d of final capacity in the short term) was agreed under a recent binational Memorandum of Understanding of May 2014. This project represents a major breakthrough, after many years of fruitless discussions, and has given way to a new era of energy cooperation between Ecuador and Colombia.

Corporate presence in other countries in the region

Colombian companies have made important inroads into the region. ISA (the high-voltage grid company) has won competitive bids to run transport grids in Peru, Bolivia, and the Sao Paulo state in Brazil, among others. The Energy Company of Bogotá has invested in the gas transmission grid in Peru, while the Public Company of Medellin (EPM) has entered the wind generation market in Chile. Promigas, a gas transmission and distribution company, has an important presence in Peru and Celsia, a generation company, is taking the first steps towards internationalization in Costa Rica and Panama. There is growing evidence that the relative maturity of the Colombian energy markets is motivating local energy companies to look for growth opportunities in the region.

'COLOMBIAN COMPANIES HAVE MADE IMPORTANT INROADS INTO [OTHER COUNTRIES IN] THE REGION.'

An integrating force in the region

Beyond the practical and business justification of the energy integration projects that make technical and economic sense, energy integration initiatives in Latin America have been fraught with misunderstandings and tension. A number of projects in other parts of the continent have

turned into political weapons or have failed to serve their intended purpose when internal markets fell short of expectations. This has been the case with the gas pipeline systems that developed in the Southern Cone, as the Morales government in Bolivia unilaterally renegotiated its gas export agreements with Brazil, Argentina suspended its exports to Chile when Bolivia cut its exports to Argentina, and local production could not supply the internal market.

Not visible in the negotiations, or made public at difficult times, is the presence of vested interests that could be affected by the alternative integrating projects that could bring more affordable energy to the region's consumers. Among these are the opportunistic populism of some political groups or the private interests behind the procurement and distribution of more expensive fuels or generation assets.

Notwithstanding difficult relations with its neighbours, Colombia has never threatened to cut electricity or gas supplies, even under the tensest circumstances, and has always honoured its energy supply commitments. The contractual relationships with its neighbours have always been governed by commercial arrangements made by independent energy or gas companies, free from political interference. Not even when political tensions with Ecuador or Venezuela reached breaking point has Colombia given the slightest hint of using energy supplies as a bargaining weapon.

'COLOMBIA HAS NEVER THREATENED TO CUT ELECTRICITY OR GAS SUPPLIES, EVEN UNDER THE TENSEST CIRCUMSTANCES, AND HAS ALWAYS HONOURED ITS ENERGY SUPPLY COMMITMENTS.'

Colombia's continuously growing presence is a consequence of the solid financial position of the energy companies that are searching for growth opportunities, as their domestic markets reach a state of relative maturity. Having a business-like attitude to their expansion into nearby markets, supported by competent technical and managerial teams, these companies are gradually gaining the confidence to participate in growing numbers of direct negotiations or calls for competitive bids, and have proven to be trustworthy and reliable.

Another set of obstacles that the country needs to overcome, in order to realize its potential to contribute energy solutions to its neighbours, is represented by the new wave of environmentalism and community activism. This has emerged in opposition to key energy development projects, including coal mining, petroleum extraction, and the construction of new hydroelectric dams.

Notwithstanding the difficulties, the picture that emerges from Colombia's combination of a strategic geographical location, a rich endowment of natural energy resources, a pragmatic political attitude towards political and economic integration, and a pool of financially strong and well-managed energy companies, is one of a gradual positioning of itself as a reliable hub for energy integration, at the crossroads of the north-western corner of the South American subcontinent.

Natural gas in Brazil: a challenging market landscape

Ieda Gomes

The Brazilian energy matrix is much diversified. Renewable energy accounts for more than 40 per cent of the primary energy offer, in the form of hydroelectricity and biomass – wood, charcoal, and sugarcane products. The bulk of electricity, 76 per cent, is produced by hydroelectric power plants. Brazil produces 2.2 million barrels per day (mb/d) of oil, most of which is consumed in the domestic market. Natural gas accounts for 12 per cent of the primary energy offer.

In 2013 Brazil produced 28 billion cubic metres per year (bcm/year) of natural gas, of which 73 per cent is associated. Domestic production has been growing steadily; by the end of 2014 domestic production is expected to reach 31 bcm/year, a growth of 11 per cent when compared to 2013. However, half of the domestic production is consumed in Petrobras operations: reinjection, oil field and pipeline operations, refineries, and Petrobras' own power generation. Local gas distribution companies (LDCs) market gas to all consumers in their exclusive geographic franchise areas.

'… THE BRAZIL MARKET IS IN THE SAME LEAGUE AS SPAIN AND THE NETHERLANDS.'

As of August 2014, natural gas consumption reached an average 99.2 cubic metres per day (36 bcm/year) including Petrobras refineries and own power consumption, so the Brazil market is in the same league as Spain and the Netherlands.

Brazil is a net gas importer, with an average 54 million cubic metres per day (mcm/day) imported via the 3000 km Bolivia–Brazil pipeline and three floating LNG terminals (FSRU). LNG imports started in 2009 and have been ramping up since then due to a very long dry period which has drastically reduced the storage availability in the main south-east and north-east hydro reservoirs. In 2013 Petrobras imported 3.72 million tonnes per annum (mtpa) of LNG; imports in 2014 are likely to be higher, already totalling 2.8 mtpa by end August 2014. Petrobras owns most of the gas-fired power plants and only imports LNG when the national power system operator (ONS) orders the dispatch of thermal capacity. The period 2012–14 has been atypical, with some plants operating as baseload. Therefore the purchase of LNG is done via spot and short-term contracts, with Brazil commanding prices similar to those seen in north Asia. In 2012 LNG represented only 11.4 per cent of the gas supply, whereas in 2014, it accounts for 20.2 per cent.

Natural gas demand in Brazil is becoming unpredictable

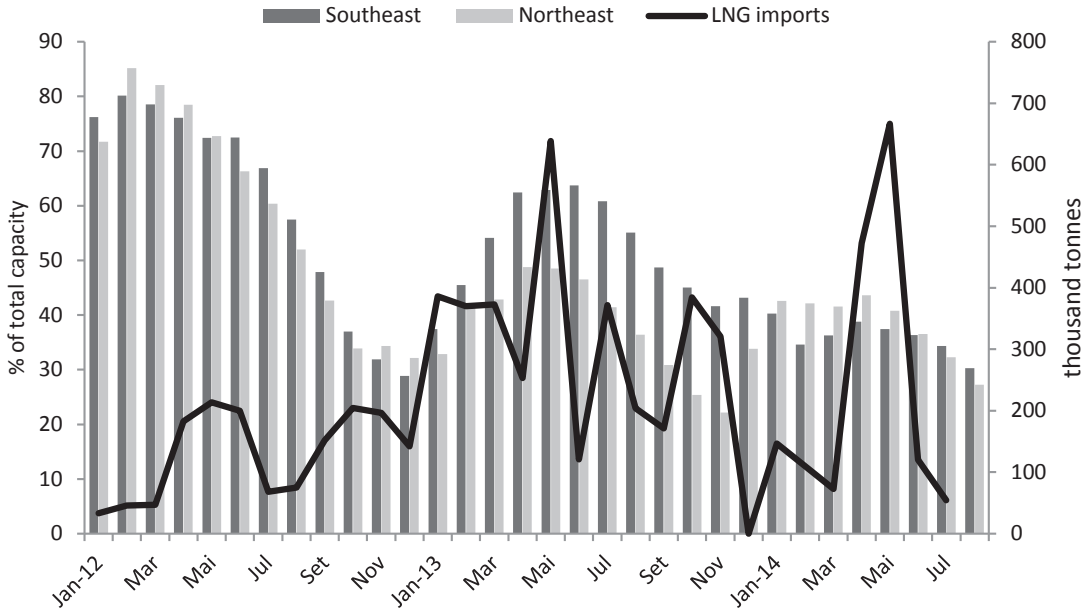
Brazil's gas market is unique when compared to other emerging countries, both in terms of market share and as regards the regulatory model. Until 1995 Petrobras had a legal monopoly on hydrocarbons exploration, production, and transportation. A constitutional amendment followed by the 1997 Petroleum Law and the 2009 Gas Law established the terms for private participation in the oil and gas sector in Brazil. Today any company established in Brazil can explore for, produce, transport, import, and export hydrocarbons, and also build LNG terminals and power plants. However, Petrobras still enjoys a de facto monopoly in gas infrastructure and is also the largest owner of gas-fired power plants. On the distribution side, Brazilian states grant exclusive 30–50 years geographical franchises to local distribution companies (LDCs) whose business models are dictated by the state government; some of these companies are totally private while others are state-controlled companies in partnership with Petrobras and private companies.

There are two levels of regulation: the National Petroleum Agency (ANP) regulates upstream and midstream activities, whereas state agencies regulate gas distribution and end-user gas prices. Some market players complain about the perceived lack of harmonization between the federal and state regulators.

There are states where large industrial and power consumers can buy gas directly from producers, but they have to pay a distribution fee to the LDCs; also since there are no other competing gas suppliers, large consumers are very reluctant to become free consumers.

Until 2011, industrial consumers accounted for 67 per cent of gas sales in Brazil, but the increased dispatch of gas-fired power plants has changed the landscape. In 2014 the power sector accounts for 47 per cent of the gas marketed in Brazil.

Industrial sales, once the backbone of the Brazilian gas market, have been



LNG imports vs hydro reservoirs capacity

stagnant since 2011. The growth of gas demand had originally been underpinned by the substitution of gas for high sulphur fuel oil (HFO), but the potential for additional HFO substitution is now quite small – only 9 mcm/day – and limited to regions in the far north and north-east which do not have pipeline infrastructure.

'… THE GROWTH OF THE NATURAL GAS MARKET IN BRAZIL IS PREDICATED ON THE GROWTH OF THERMAL POWER GENERATION.'

The other market segments – transport, commercial, and residential – are constrained by competition with subsidized LPG and petrol. The mild weather in most Brazilian regions is a barrier for traditional residential gas applications, such as space heating and hot water. The cost of building infrastructure in large cities is also high and time-consuming, due to a complicated permitting process.

Therefore the growth of the natural gas market in Brazil is predicated on the growth of thermal power generation.

Based upon their long-term electricity demand forecast, the Ministry of Mines and Energy (MME) conducts annual auctions for power plants which are due to operate within five years, the so called A-5 auctions. The Ministry fixes the variable cost of operation (CVU), which will be paid when the plants operate; the bidders must bid a price below a ceiling composite price, the 'ICB' which should theoretically remunerate capital and other fixed costs including the take-or-pay of the gas contracts. Gas-fired power plant investors need to satisfy the Ministry that they will sign 25-year gas supply agreements and, in the case of domestic gas, that the gas reserves are sufficient to underpin such long-term gas contracts.

Due to its extensive portfolio, Petrobras is currently the only gas producer which could meet such criteria. However, it has not been in a position to commit to supply any private power generation project and it also seems to be willing to save its domestic gas for its own power plants. Currently there is only one independent gas-cum-power project in north-east Brazil; this monetizes gas from an onshore non-associated gas field in the northern state of Maranhao to a group of 852 MW power plants.

Due to the lack of domestic gas, independent power developers have been trying to develop projects based on LNG. The Ministry defined the CVU and ICB for the upcoming A-5 auction at, respectively, BRL 250/MWh and BRL 197/MWh (equivalent to US$113/MWh and US$89/MWh) in September 2014. However, in the wake of the results of Brazilian elections, the Brazilian Real has depreciated significantly and as of 14 November 2014, the prices have dropped to US$96/MWh and US$76/MWh, respectively. The power investors believe that they would need regasified LNG prices of US$11–13/MMBtu at the plant gate to be able to dispatch at a US$113/MWh CVU. These prices are indeed below the current level of LNG prices being negotiated on long-term contracts.

The power auction criteria allow for LNG prices to be indexed to either Henry Hub (HH) or Brent, but although HH-indexed prices are currently more competitive than Brent-indexed prices, the fixed-price component of the US-based projects plus shipping and regas costs, are much heavier than the variable HH component. Due to the unpredictability of the plant dispatch in Brazil, the investors would have to build all fixed costs into the ICB, which is currently insufficient to allow for the remuneration of all fixed costs.

In order to overcome the constraints of the volatility of the demand and the low auction price levels, LNG suppliers and power investors will need to develop creative price formulae and very flexible LNG contracts. These constraints will probably be a huge impediment for independent LNG-cum-power projects, unless the MME allows for realistic power prices which take into account the market prices and take-or-pay obligations for LNG. In the meantime electricity prices in the spot market are currently sky high, circa US$300–350/MWh in October 2014.

The need for gas-fired power plants is becoming more pressing, because the environmental permitting process makes it almost impossible to build hydro power plants with reservoirs; suitable back up plants should thus be developed as a matter of necessity. As power demand continues to grow, government forecasts have identified the need for 48 GW of additional power capacity between 2013 and 2022, of which only 1.85 GW is gas-fired and 9 GW wind. Only 7 GW of reservoir capacity will be added in the same period.

What it the outlook for 2020?

Brazil is home to a massive investment programme to develop its upstream oil resources, most of it on ultra-deep water frontiers, particularly from pre-salt blocks. According to industry and government sources, Petrobras and international and local oil companies will need to invest US$40 billion per annum in offshore E&P until 2022 to deliver production goals of 4.2–5 million barrels of oil per day. A significant volume of associated natural gas should be produced in this horizon, but there is uncertainty about the actual gas to be available to the market. The key questions concern the volumes needed for reinjection, the high content of carbon dioxide

(ranging from 10 to 40 per cent), and the cost of infrastructure to deliver gas to the shore. The industry is projecting that the domestic gas offer will nearly double from current levels to 86 mcm/day (31 bcm/year) by 2020. Petrobras has planned for three evacuation pipelines, aiming to connect some pre-salt blocks to the markets in the states of Rio de Janeiro and Sao Paulo, with total capacity of 50 mcm/day. One of the pipelines is already in operation and the other two are still being procured, with commissioning expected by 2016–17. It is still unclear what additional infrastructure will be required to deliver the remaining 36 mcm/day to the market.

Despite the significant increase in domestic gas supply, Brazil will continue to be dependent on Bolivian gas and LNG imports. Unless the government changes the power auctions rules, allowing for firm thermal power dispatch, Brazil will need to rely on 8.5–10 mtpa of flexible LNG supplies, which will be very costly. At current prices, regasified spot LNG costs US$17–20/MMBtu, whereas legacy power plants pay only US$4.6/MMBtu for their gas supplies.

'THE LEAST-COST ALTERNATIVE FOR BRAZIL IS TO DEVELOP ITS OWN DOMESTIC GAS RESOURCES …'

The least-cost alternative for Brazil is to develop its own domestic gas resources, as less than 5 per cent of the country's extensive sedimentary basins have been effectively developed. In order to do this, the government needs to contribute towards de-risking natural gas exploration and development, to attract private investors. This can be done by: promoting additional geological surveys, improving the terms and conditions for the E&P auctions (for example, lower signature bonus and royalties for gas fields), promoting the monetization of independent producers, and reducing market and infrastructure risks by ensuring attractive conditions for the building of new pipelines.

Brazil: pre-salt outlook

Virendra Chauhan

Introduction

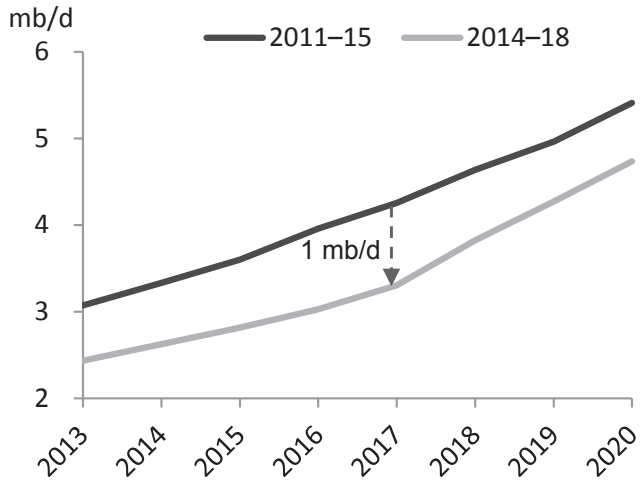
Less than 10 years ago, at the height of the commodities boom, Brazil was assured a place as an oil world powerhouse, following the discovery of oil in its subsalt basins. Much faith has been put in Brazil delivering the barrels needed to keep the medium-term oil market in reasonable balance. This optimism had been brought to the forefront of the global oil and gas industries by the 2007/8 discovery of the vast pre-salt basins, specifically the Tupi field. This ranks alongside Kashagan as one of the largest and most significant oil discoveries of the past few decades. However, as has often been the case in recent history of the oil markets, a number of project delays and cost overruns have since taken the shine off the initial optimism.

State-owned operator Petrobras accounts for over 90 per cent of Brazil's production and has been at the centre of development in the country's oil sector. Petrobras has registered a reserve replacement ratio above 100 per cent for each of the past 22 years, with the 2013 figure at an impressive 135 per cent. This comes at a time when other major oil companies have been struggling to add incremental reserves to their portfolios. Despite the addition to reserves, Petrobras missed its annual production target in the period between 2003 and 2011 (revising its production forecasts downwards see graph on the next page), and even saw its annual output decline over the past two years, falling by 2 per cent in 2012 and by 1.6 per cent in 2013.

'STATE-OWNED OPERATOR PETROBRAS ACCOUNTS FOR OVER 90 PER CENT OF BRAZIL'S PRODUCTION.'

So what has slowed progress in the Brazilian oil sector? We argue that Brazil's upstream sector faces a number of challenges which include: regulatory barriers, a massive financial burden (the world's largest corporate expenditure programme amassing US$220.6 billion and increasingly funded by debt), high production costs, and steep decline rates. There has also been waning interest from major international oil companies (IOCs) in co-financing projects. The country's deep-sea bonanza has become less alluring, whilst oil companies have also been adapting to a changing energy landscape; this has been altered by a focus on capital discipline, US shale, and the emergence of other frontier energy sources, such as in deepwater Africa.

We begin by considering the status of Brazilian liquids production today, with a particular focus on the evolution of



Petrobras' production forecasts, million barrels per day (mb/d)

Source: Petrobras

pre-salt production. Brazil produces 2.3 mb/d of liquids output, approximately 75 per cent of which comes from the post-salt reservoirs in the Campos basin. Campos pre-salt production began in 2008 from the Jubarte field located in the Parque das Baleias region. Thereafter, production began at the Baleia Franca field in the second half of 2010, followed by the Baleia Azul region using the FPSO *Cidade de Anchieta* in September 2012. At the end of 2013, pre-salt production in the Campos Basin reached 0.17 mb/d and whilst a split is not available for 2014, anecdotal evidence suggests that the first half of the year has seen an acceleration in well activity, and therefore output.

The Santos Basin is the other main basin in Brazil, home to one of the most promising exploration and production (E&P) areas offshore Brazil. The pre-salt has been a central focus of E&P activities, with 13 of the 15 wells being drilled in that region in 2013. Several discoveries have been made in the pre-salt reservoirs, whilst the development of previous discoveries has allowed Santos Basin output to rise steadily. Output has increased from 0.11 mb/d in January 2013 to 0.28 mb/d by year-end, as five out of nine production units produced first oil during the year. Output averaged 0.19 mb/d in 2013, higher year-on-year by 80 kb/d (thousand barrels a day). The steady growth trend has continued and by August 2014 pre-salt production (Santos and Campos) reached 0.58 mb/d. This was accomplished eight years after the first pre-salt discovery in 2006, and was achieved from around 30 wells, highlighting the high productivity of pre-salt fields. Petrobras has set a target of achieving more than 1 mb/d of output from pre-salt by 2017 in the fields they operate. Future production from the Santos Basin will be predominantly from deep and ultra-deepwater fields, with 13 major projects in the development pipeline.

Challenges: high decline rates, cost escalation, and regulatory reforms

Decline rates

Analysis of well data available from the National Petroleum Agency (ANP) indicates that rampant, double-digit declines in existing fields are offsetting the efforts made in upstream. A recent report showed that on an annual basis average production declines are between 17 per cent and 20 per cent. This number increased from 14 per cent in 2005 to 23 per cent in 2011, before falling back to 21 per cent in 2012 and 17 per cent in 2013. In 2014, increased operational efficiency in the Campos basin is believed to have reduced declines further. Assuming a 17 per cent decline on 2 mb/d of liquids output, some 0.3 mb/d of production capacity needs to be brought online each year to keep output stable. Given such steep levels of decline, any equipment and project delays quickly show up in a declining production trend. Broadly speaking, more than one large FPSO is needed each year to offset declines. That number rises as the field ages. This holds particularly for pre-salt discoveries.

'… ON AN ANNUAL BASIS AVERAGE PRODUCTION DECLINES ARE BETWEEN 17 PER CENT AND 20 PER CENT.'

Brazil has installed around four barrels of production capacity for a net gain of one barrel in output over the past 12 years. It is no surprise that Petrobras has had difficulties reaching its various production goals, as presented in the annual strategic plans over the years. Delays in construction are common and, given the aforementioned decline rates, translate into immediate production drops.

Cost escalation

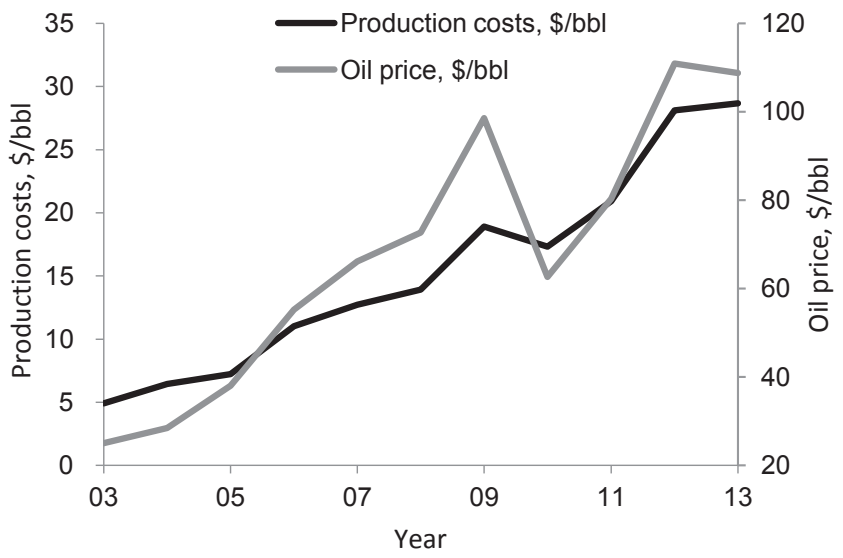
Cost escalation has also played its part. The evolution of Petrobras' five-year business plan is a tale of increased costs and production target misses, and though the latter have become a well-known feature for major oil companies over the years, Petrobras perhaps epitomizes the challenges facing the upstream sector.

Petrobras' E&P capex has increased almost 2.5 fold, from US$65.1 billion in 2008 to US$153.9 billion in its 2014–18 business plan. The percentage of capital allocated to E&P has increased from 58 per cent to 70 per cent, with Petrobras' total five-year capex increasing from US$112.4 billion to US$220.6 billion. The investment programme was revised upwards for five consecutive years, and only in 2014 did Petrobras reduce its overall capex programme, by US$16.1 billion, although this was solely attributable to a US$26.1 billion downward revision to spending in the refining, transportation, and marketing division.

Petrobras has seen a sharp rise in production costs for existing wells, as well as in costs related to equipment and facilities, labour, and materials. Production costs in 2011 and 2012 on average were 36 per cent higher than in 2010, and data for 2013 indicate a similar trend. The 10-year compound annual growth rate (CAGR) in production costs is 22 per cent. From 2003 to 2013, production costs have moved largely in line with oil prices (see graph below). However, given oil has, on a quarterly basis, remained steady at around US$110 for three years, and Petrobras continues to experience rising costs, the financial picture is, unsurprisingly, looking negative.

Currently, Petrobras estimates the breakeven cost of its production to be US$45–55 per barrel for the pre-salt. This cost estimation is based largely on both the pool of existing conventional resources and the assumption that all of its reserves will be transformed into revenues. The high degree of complexity involved in deep and ultra-deepwater extraction requires expensive technology and manpower, while the existence of several technical challenges requires further expenditure to overcome. Also, unlike easily accessible conventional oil, there are high costs involved in getting the oil onshore from wells that involve distances of anywhere between 340 and 800 km.

Therefore, the recent pull-back in oil prices will be closely monitored by Petrobras, who in their 2014–18 business plan assumed a US$105 oil price in 2014 and US$100 in the longer term.



Petrobras' production costs vs oil price

Sources: Company data, Energy Aspects

Regulatory reforms

The change in the regulatory framework in 2010 was an important milestone in the history of the Brazilian oil sector, with the enactment of the following laws:

- *Law 12,351* – aims to regulate the exploitation and production of oil, gas, and other hydrocarbon fluids under the regime of production-sharing in the pre-salt (and other strategic areas) and create a Government Social Fund.
- *Law 12,304* – Pre-Sal Petróleo SA (PPSA), an entirely state-owned enterprise, was created by this law to monitor and manage production-sharing contracts signed with winning consortia. An operational committee will be responsible for the central decisions within these consortia.
- *Law 12,276* – provided for an onerous relinquishment regime, according to which 5 billion barrels of exploration rights were transferred to Petrobras with due compensation.

The reforms have undoubtedly shaped the rate, or rather lack, of progress in the Brazilian upstream sector. Once the scale of the pre-salt region became apparent after the Tupi discovery, the government suspended auction rounds, offering new acreage for exploration to oil companies, and set out to rewrite Brazil's oil laws. Due to the excessive bureaucracy that plagues Brazil (in common with many other resource-rich nations) this process took several years. Some argue that the uncertainty surrounding the reforms halted what had previously been annual auctions – leases sold through such auctions had helped more than double Brazilian crude output from under 0.9 mb/d in 1997 to 1.9 mb/d in 2008.

Petrobras' operational exclusivity in the pre-salt basin and strategic regions granted by Law 12,351 is one of the most criticized aspects of the new

statutes, since it may entail important drawbacks in the Brazilian oil sector. Because of the significant investments required in exploring such an enormous area, exclusivity has three possible consequences:

- A considerable reduction in the pace of exploration because of Petrobras' difficulty in coping with the huge investments required to be able to explore this vast area.
- A significant increase in Petrobras' debts to finance exploration activities.
- Reallocation of the company's international projects to allow focus on domestic exploration and the pre-salt basin.

Conclusion and implications for global oil market

Brazil's upstream prospects will undoubtedly play a key role in keeping the oil market in balance over the near term. Discoveries such as Tupi and Libra have catapulted Brazil into the limelight, with key agencies suggesting that Brazil will play a critical role in the broader non-OPEC supply outlook. Back in 2006, the IEA predicted Brazil's output surpassing 3 mb/d by 2009; that expectation now extends to 2018. Petrobras, meanwhile, has lowered its production targets consistently over the past few years as oil output growth continues to disappoint. This is not due to disappointing results from Brazil's pre-salt production. Quite the contrary; it has reached record highs of more than 0.5 mb/d as of August 2014, and the discovery-to-production period of eight years surpasses previous large discoveries in other parts of the world. The second half of 2014 has certainly seen Brazilian production turn a corner, with liquids output hitting a record high of 2.4 mb/d in August as a steady stream of high productivity pre-salt wells have been brought on stream. However, that said, recent experience suggests that scaling up production will remain a substantial challenge.

The impact and effectiveness of local content policy on oil exploration and production in Brazil

Edmar de Almeida and Diana Martinez-Prieto

Local content policy plays a fundamental role for Brazil. It is through local content policy that the country is seeking to reconcile expansion of the oil sector with its industrial development. Despite the significant evolution of this policy in recent years, several improvements are needed to balance the objectives of promoting industrialization with the competitiveness of oil exploration and production activity in Brazil. Local content policies have an important positive impact on Brazilian industries, particularly the Brazilian shipbuilding industry. At the same time, local content commitments currently represent an important risk factor for exploration and production (E&P) projects in Brazil. The local content commitments are assumed long before the acquisition of product and services for the projects. The risk of cost overruns, delays, and low quality of products is a key consequence of the existing policy, affecting the attractiveness of Brazil's oil and gas industry. There is a clear space to introduce adjustments in local content policy in Brazil, in order to reduce the potential risks for E&P projects, while still supporting industrialization in Brazil. For future projects, allowing greater flexibility to adjust local content commitments as development plans are established would help reduce project risks. Shifting from an approach that penalizes non-compliance to one that rewards operators who exceed commitments would likely represent a more effective incentive structure. For contracts already signed that are unable to meet local content requirements, there is a range of pragmatic adjustments that could be considered in addition to those already mentioned.

Commitment to local content

The regulation of the oil industry in Brazil has been characterized by a strong emphasis on promoting local content. The main instruments of local content policy are the commitments to purchase local goods and services made by concessionaires in the bidding rounds for exploration blocks. The percentage of this overall local content commitment is part of the criterion for assessment of offers made in the bidding rounds.

'THE REGULATION OF THE OIL INDUSTRY IN BRAZIL HAS BEEN CHARACTERIZED BY A STRONG EMPHASIS ON PROMOTING LOCAL CONTENT.'

It is important to note that the commitments made in the bidding rounds become part of the concession contract and apply to the entire period of exploration and field development. In other words, companies commit to buying those Brazilian goods and services that they will need during a period that could last 10 years. In most

cases their needs are not well known, since they depend on the results of the exploratory campaign. Without knowing precisely what goods and services will be needed, or what the Brazilian market conditions will be at the time of purchase, the commitments of local content become very relevant economic risks for oil projects.

Certification and compliance process

The methodology for establishing local content commitments by operators and for certifying local companies has evolved significantly over time. In the first six bidding rounds, rules for certification were relatively flexible. As the government increased the importance of local content in auctions, competition drove the companies to commit to extremely high levels of local content –the average commitment in the development phase increased from 40 per cent in the Third Round to 90 per cent in the Sixth Round in 2004.

In 2007 the government introduced a new local content certification process. By this process, the operator was required to hire specialized certification companies to prove their compliance with local content commitments. In 2009, the National Petroleum Agency (ANP) introduced a new methodology for local content commitments in the bidding rounds. According to the new rules, operators' local content offer must detail the numerous products and services expected to be used. For each item, the company has to make a local content offer, respecting a minimum and a maximum value by the ANP.

'THE WAY IT IS CURRENTLY STRUCTURED, BRAZIL'S LOCAL CONTENT POLICY REPRESENTS A MAJOR RISK FOR OIL PROJECTS.'

Once the very detailed local content commitments are made, companies have few instruments to manage the risks of overpricing and delays in local purchases. They must undergo a rigorous and complex system of certification of their purchases of goods and services and pay high fines if they do not comply with contractual commitments. The way it is currently structured, Brazil's local content policy represents a major risk for oil projects.

Impact of local content agreements

To analyse the impact of Brazil's local content policy on the economic evaluation of projects, from the position of operators focused on offshore oil E&P in Brazil, Diana Martinez-Prieto developed a deterministic model (discounted cash flow) and a stochastic model (Monte Carlo) that simulate the impacts of risks (arising from additional costs, fines, and delays) of not meeting the percentage of the overall local content on a hypothetical project at a field holding 500 million barrels of recoverable oil (Martinez, Diana, 2014, The Local Content Policy and investment decisions in Brazil, Master's Dissertation at UFRJ). The simulations run for a typical oil project (with local content commitment of 37 per cent in the exploration phase and 55 per cent in the development phase) demonstrated that the current Brazilian local content policy has a very significant impact on the project economics. The study simulated the impact of 30 per cent of non-compliance with the local content requirements, as well as 30 per cent additional costs for domestic products than initially anticipated, and a one-year delay in achieving first oil. In this scenario, the likelihood of the project having a negative net present value (NPV) increases from 3 per cent to 47 per cent. This study made it clear that the risks of local content can be economically crippling for many E&P projects.

Even though local policy can clearly have a negative impact on oil and gas investments in Brazil, it also has positive implications. This policy has been effective in increasing the domestic production of goods and services related to the oil industry. The shipyard industry in Brazil, for example, has experienced an important revival in the last 10 years. Brazil already has the fourth-largest offshore fleet and the third-largest shipyard industry in the world. Brazilian dominance in this market will likely grow since there are about 20 floating production, storage, and offloading vessels (FPSOs) under construction and 48 more planned to go on stream by 2025. By 2035 between 75 and 85 new FPSO systems should be added in Brazil. The share of Brazilian-built FPSOs tends to increase as new shipyards currently under construction start to operate. Therefore, the large demand from pre-salt projects and local content policies can help Brazil to become one of the world's centres for the offshore industry.

Potential improvements to local content policies

Nevertheless, it is fundamental to seek a better balance between the local content incentives and the risks for oil projects. In this sense, it is essential to design and implement mechanisms that allow for greater flexibility in establishing local content commitments. As an alternative to the current process, where the full commitment is established in the bidding round, a more successful model would give space to define and refine local content targets in connection with the preparation of the production development plan. Thus, the company could make feasible commitments based on the best knowledge of its goods and services needs and the context of supply in the domestic market.

When including local content as an important dimension of the field development plan, the ANP would strengthen its monitoring capacity, as it would know the local content strategy of the concessionaire. Moreover, the ANP would better understand the local industry goods and services bottlenecks, empowering itself to address the task of assessing applications by companies for exemptions from commitments for local purchases due to lack of competitive offerings, as provided by the legislation.

The logic of the current local content policy is to punish those companies that do not comply with minimum requirements. However, outcomes could be improved by the introduction of new incentive mechanisms – strengthening local content policy by granting incentives to companies that exceed their commitments. Several incentive mechanisms could be considered to encourage concessionaires to seek increasing levels of local content, such as (i) reduction of specific duties; (ii) competitive advantages in the bidding rounds of exploration blocks; (iii) reduction in fines for non-compliance with commitments made in other concession contracts.

'HOWEVER, OUTCOMES COULD BE IMPROVED BY THE INTRODUCTION OF NEW INCENTIVE MECHANISMS …'

Issues related to current contracts

Finally, it is important to consider the contracts already signed. Many of these contracts have included local content commitment levels that are not attainable and/or result in costs that are too high for E&P projects, given the current context of the goods and services market in Brazil. In this case, a pragmatic reflection on the best path for the country becomes important. The simple application of high fines for non-compliance will certainly not contribute towards accelerating the development of a competitive goods and services industry in Brazil. Currently, fines must be paid to the Treasury and do not generate benefits for the supplier industry. It is important to have a discussion on how to turn possible contractual penalties into mechanisms that encourage the development of the goods and services industry. Possible fines could turn into investment commitments in the supply chain, including research and development. Similarly, local purchases for projects outside Brazil could be considered for rebates in the commitments of projects in Brazil. Such a mechanism would help to reduce potential fines and promote exports of national goods and services.

Mexico: positioning for a transformational upstream opening in 2015

Ivan Sandrea and Read Taylor

Introduction

Since the late 1800s, Mexico has been a prolific, predominantly light oil producing region; its development has mirrored the initial oil booms (which were occurring at the same time) on its borders in California and Texas. Mexico has multiple established billion barrel-sized fields onshore and offshore, with reservoirs having high production rates throughout several key regions.

In 1937 the government took over the petroleum industry, creating the state-owned monopoly PEMEX as the country's sole oil and gas producing company and investor. Over the last two decades PEMEX has developed a large portfolio onshore and in shallow water, underpinned by attractive low costs and P1 P2 P3 reserves. However, it is estimated by CNH, the Mexican upstream regulator, that there are over 260 fields that are in decline or underdeveloped and in need of investment. These reserves lack the traditional development investment programmes that are successfully being implemented in the USA including: down spacing, stimulation and enhanced oil recovery (EOR) methods, deeper drilling technologies and completion methods including the horizontal drilling and fracking so popular and successful in its northern neighbour. Mexico's proven base of resources is quite unique and within the top 10 on a world scale relative to other international emerging areas that have received high investment interest over the last five years, such as Uganda, Kenya, Tanzania, and Morocco. Mexico is set to become one of the most attractive new emerging areas in the E&P industry.

Several factors – such as the recent (2004–12) 25 per cent reduction in internal country production levels, an increase in consumer demand for refined products and increase in gas and oil imports, the success of the US shale boom, and a need to increase

'MEXICO IS SET TO BECOME ONE OF THE MOST ATTRACTIVE NEW EMERGING AREAS IN THE E&P INDUSTRY.'

long-term GDP growth – have required the government to re-evaluate its long-held energy strategy. When compared with the higher growth attained in other major oil-producing environments in the Latin America–South American region which enjoy investor-friendly regulatory systems (such as Brazil, Colombia, and Peru) Mexico's service contract model, in place prior to 2014, has not yielded the results expected.

In the recent landmark, far-reaching energy reform process, Mexico revised its Constitution and created significant structural changes across a short time frame that allowed for private investment in the energy sector for the first time since 1937. This followed a proven model which sets apart well-defined institutions to handle the various roles. A well-organized ministry (SENER) supported by the upstream regulator CNH conducting a transparent and open bid process initiated in 2014–15, will allow foreign investors to participate in a world-class hydrocarbon province. This is a timely and fortuitous move for both the Government of Mexico and investors alike. Mexico will benefit from growth in production via investment in both production (in existing mature fields) and exploration.

On 13 August 2014, Mexico announced the first upstream licensing round for private participation. This process includes two primary sets of opportunities: JV opportunities with PEMEX, and exploration and development opportunities without PEMEX. The JV opportunities with PEMEX include 2.6 billion barrels of oil equivalent of 3P reserves and close to 81 thousand barrels per day of production across various assets including: deepwater discoveries (both oil and gas), extra-heavy oil fields (shallow water and onshore), and large mature fields (EOR potential). Standalone opportunities (without PEMEX) include: 39 deepwater exploration blocks, 70 unconventional exploration blocks, and 60 developed fields across 28,500 square kilometres (11,000 square miles).

'ON 13 AUGUST 2014, MEXICO ANNOUNCED THE FIRST UPSTREAM LICENSING ROUND FOR PRIVATE PARTICIPATION.'

CNH estimates the value of investment for the assets in Round 1 (including PEMEX 'farmouts' or JVs) to be US$12.6 billion a year, representing a total of US$50 billion over a four year time period (2015–18). With the bid round in 2015, operators will kick off work programme activities from 2016 onward, with likely expected growth in production as early as 2018 anticipated by Morgan Stanley (September 2014). The figure is expected to reach 3.0 mb/d (million barrels a day) in 2018, (up from 2.5 mb/d), and 3.5 mb/d in 2025 for new 'green' fields. Similarly, gas production is estimated to grow from 5.7 bcf/d to 8 bcf/d in 2018, and up to 10.4 bcf/d in 2015.

The future players in Mexico

After the reform, PEMEX is now a peer and competitor to the oil and gas industry in Mexico. However, it is expected that PEMEX will maintain its dominant position through retaining key production and exploration areas as part of Mexico's Round 0 process. Mexico's proven oil environment should attract a high level of competition for the upcoming Round 1 assets, and beyond, which will change the landscape. Mexico represents not only a new country opening, but new basin opportunities and technological play. This increased competition will mainly come from seven principal groups.

1 *Traditional Majors* who are currently looking to reset in lower-risk proven high-potential reserve base off the back of rationalizations programmes, and who seek expansion primarily to their deepwater portfolios in relatively lower risk environments.

2 *NOCs* that that are seeking to expand their portfolios, either to meet rising demand at home or simply grow their upstream business as part of internationalization programmes.

3 *Regional and US Independents* who are cash rich off the back of strong unconventional oil success in the USA or Colombia, their own recent non-core asset rationalizations, five years of steady balance sheet strengthening from US$100/barrel oil pricing, and who are looking for the next best place to go that mirrors their investor friendly focus in the USA.

4 *Private Equity backed players* who have, since the 2008/9 crash, found investors willing to build companies privately up to materiality rather than suffer illiquidity issues in the historically difficult start-up markets of TSX and AIM; this is a somewhat newer force coming to the table, with large long-term capital commitments needed to secure these higher stake initial value assets with proven reserves as well as undertake exploration opportunities.

5 *Local Mexican companies* with management teams that have expertise in E&P and the service sector that can be combined to re-position historical service sector players into upstream players.

6 *Service Companies* primarily from the USA and Canada taking advantage of their well-established proprietary technologies and expertise in conventional and unconventional methods to satisfy the upcoming increase in demand for services and products.

7 *Other players*, such as trading companies and integrated refineries with growing E&P portfolios that focus on niche markets.

Moves by a range of the above types of companies are happening now in Mexico. Morgan Stanley estimates local and international energy companies could ultimately drive capex to more than double by 2020, from US$25 billion today.

In order to be successful independently, or in partnership with PEMEX, companies must develop not only key differentiators in technology, operational efficiency, efficient capital deployment, and enhanced production methods in this oil proven environment (with high P1 P2 P3 numbers in assets being offered) but also establish mid- to long-term sustainability through a focused technical approach to understanding the ongoing and still-developing reform process and regulatory environment, as well as Mexican social and cultural ideas. The companies that can position themselves wisely in the early stages of this important opening will benefit from building a material base early (including mature fields and exploration acreage) and developing strong drilling portfolios, a reserve base, and production growth.

Capital markets and M&A environment: North America in focus

Prior to 2014, following the 2008/9 crash, investors wanted to make up their losses and assumed higher risk portfolios in the general oil and gas asset market. At this time the market was giving a premium to explorers like Tullow, Anadarko, Africa Oil, Ophir, and others who were making significant gains in Africa. This trend, however, changed in 2014 as investors, attracted to recent success stories of low-risk bread and butter development plans of companies such as Continental and Pioneer in the USA, shed their appetite for international risk. International buyers (primarily NOCs) have also stopped buying – their share is down to only 30 per cent of total deal activity.

'NORTH AMERICA CONTINUES TO DOMINATE THE MARKET, WITH US$85 BILLION IN TRANSACTIONS TO OCTOBER 2014.'

According to a study (Derrick- MA activity 2014) the MA market hit a low in 2007 with a combined activity of US$151 million. In 2010, the market went up to US$212 million then retreated in 2011 to US$173 billion. A peak in activity in 2012 of US$275 billion was followed by a five-year low in 2013 of US$141 billion, but 2014 is set to finish strongly with projected total activity of US$198 billion. This growth comes with a renewed focus on core assets, with money becoming available in the first half of 2014 for asset purchases. However, the second half of 2014 and into 2015 is characterized by weaker oil prices and asset rationalizations by majors.

North America continues to dominate the market, with US$85 billion in transactions to October 2014 (Energy Intelligence). A strong buyers' market continued in tight unconventional oil plays in the USA, with high activity from Bakken shale to Texas. So then the question becomes: where do these independents and majors go now, and where is the next big thing? Active buyers are cash-rich PE/non-traditional buyers, ex-Middle East, or small independents looking to build critical mass.

Emergence of private equity: implications for Mexico

The small independents and new players have traditionally led the charge into new countries, de-risking the main plays and creating substantial value to investors and host countries. Since 2009 some small independents have fallen out of favour with investors due to over-weighted risk profiles and illiquidity in the volatile markets; they have therefore not been able to raise fair-priced equity. The AIM EP LSE AIM Oil and Gas Index has fallen by 40 per cent in the last five years (since 2007) over a period where the Brent oil price has increased by 16 per cent. A new source of capital is needed.

According to Richmond Energy Partners (REP) in an August 2013 study, only one in 15 companies managed to sustain a market capitalization figure of US$500 million (US$500 million market cap). Three were acquired, one grew four-fold, and the remaining shrank by 50–95 per cent. Of the 103 companies smaller than US$500 million market cap only seven are now at or larger than US$500 million market cap. Those that grew had a single success factor, they focused on one country. Sweet spots for these companies and subsequent investor support include production reaching a level of 18 to 40 kb/d, and reserves of 120 to 220 mb. Some of these companies had reserves prior to 2007 but the growth is approximately three to five times (singled out as the biggest factor of success) the production figure over the period, and between two and ten times the figure for reserves. Equally in order to build these production portfolios successful companies managed a higher rate of debt vs equity. The study goes on to point out several themes:

- Higher capitalized companies initially fare better – it takes a billion to make a billion or more.
- Companies should be focused geographically.
- Acreage is proven with room to grow reserve base organically.
- Discoveries should be brought to production quickly and cheaply to recycle cash flow into exploration appraisal.
- Management teams should be able to access debt markets.

- Successful assets are attractive for early exit geographically and commercially.

As of April 2013 it is estimated that a figure of over US$50 billion 'firepower' has been targeted for oil and gas investment by private equity, creating 'powder' of over US$56 billion. Notable recent moves by PE include:

- L1 Capital aims to invest US$10 billion in oil and gas.
- Riverstone closed an oversubscribed US$7.7 billion fund in June 2013, the biggest in its history; the fund will focus on the broad energy sector.
- In early 2013 EnCap closed its biggest fund, with US$5 billion to be invested in the USA.
- KKR is raising a US$1.5 billion fund for oil and gas in the USA.
- Carlyle is raising more than US$1.5 billion for investments in Africa and Europe.
- Warburg Pincus closed its XI fund at US$11.2 billion.

One potential driver of this increased interest by PE in oil and gas investment has been a period of relative price stability in oil prices and low volatility. It of course remains to be seen how the PE interest will be affected by the recent downturn in pricing of October 2014.

The model of capitalizing successful start-ups and growing an E&P company has changed. Private equity and its business model suit this new environment, having the capital strength, expertise, and connections to unique technical management teams and partnering companies for supporting efforts.

Exploration and production success: small is better

In March 2014 Bernstein Research reported that, dollar for dollar, larger companies struggle to bring the same amount of unrisked resource through to the drill bit as their smaller counterparts often do. Exploration budgets tend to be around 7 per cent of market cap, across the whole group in the Bernstein sample.

'E&PS' EXPLORATION BUDGETS (RELATIVE TO THEIR SIZE) ARE THREE TIMES LARGER THAN THOSE OF THE MAJORS …'

E&Ps' exploration budgets (relative to their size) are three times larger than those of the majors; averaging 10 per cent of market capitalization for the smaller explorers, versus 3 per cent on average for the Integrateds. For smaller E&Ps, targeted resource is a linear function of exploration budgets. On average, 200 million barrels of oil equivalent can be targeted per US$100 million of exploration budget. But this 'straight-line relationship', according to Bernstein, flattens off considerably for larger explorers: US$1 billion budgets fall short by 30 per cent, US$2 billion budgets fall short by 40 per cent, and US$4 billion budgets fall short by 60 per cent. The International E&Ps achieved a success rate of 55 per cent on average last year, which was –67 per cent inversely correlated with these companies' market capitalizations. We believe this is driven by exploration that is more selective, from smaller, more capital-constrained E&Ps. Based on 2013–4 data, smaller explorers spent more heavily on exploration. For the money they spent, they were able to target more resource. And while targeting more resource, they may have been able to achieve better success rates, as a function of being more capital-constrained and selective.

For those new companies starting in Mexico, certain recent market fundamentals or benchmarks hold. Fundamentally the oil and gas business is about finding and developing reserves at the lowest possible cost and selling/marketing them at the highest possible price; in this manner the State is also assured of making significant income. Strong correlation between enterprise value (EV) and 1P reserves exist, and there is an average reserve value of US$16 per boe, with some variances geographically and oil vs gas fiscal terms etc. Most companies have a market value of 1.3–2.1 × their reserves value. This is in line with a value of probable 2P reserves, contingent resources, and exploration upside. The portfolio in Mexico, having P1 P2 P3 reserves, allows companies to come in on the curve sooner, and with potential higher resource value relative to other emerging countries or to asset opportunities available in other more risky frontier basins.

Global opportunity set: Mexico's turn

For the period 2014–15 notable exploration bid rounds include Myanmar, another emerging area which is undergoing reform, with its first real offering in onshore (oil potential) and offshore (gas potential) blocks. For offshore, Myanmar released 60 blocks and received 64 competitive multiple bids from 36 different companies. Other international examples include: Liberia, which recently offered four blocks; Suriname three blocks; the North Sea with 17 blocks; Egypt with seven blocks; Oman with five blocks; and India with 35 blocks. Also rounding out the list internationally are Australia, Indonesia, and Thailand with annual bid rounds. A total of 40 bid rounds take place annually.

For comparison purposes in other North America bid rounds: Canada has had recent offerings in Newfoundland with six blocks having a total of 266 sq. km. In the USA, annual bid rounds continue in the Alaska and GOM; the East Breaks and Alaminos areas near the offshore USA–Mexico border having recently seen the recent Lease sale 238 of 4,026 blocks in Shelf areas.

For investors interested in Latin America, Colombia, a mature area having seen over 12 years of bid rounds, continues to offer and receive interest from majors and independents alike in onshore conventional, unconventional, and offshore deepwater acreage. However the recent offering of 95 blocks attracted only 26 bids in areas deemed to have not been de-risked, or with moderate perceived potential, and only one of the 18 unconventional blocks received a bid. Brazil's recent bid rounds received high relative interest in Equatorial Margin acreage offered and the pre-Salt acreage 'Libra Round', with winning bids from Total Shell CNPC and CNOOC. Brazil could continue subsequent rounds in 2015, provided its current deteriorating economy, its political process (mixed majority and wavering support), or recent Petrobras corruption scandals don't delay the round. Peru, a country that gets a lot of interest from a select group of independents, recently announced (in August 2014) a bid round in one Basin Talara 2 onshore large exploration areas.

Mexico is offering 169 blocks (including some 60 fields) in Round 1 and a material reserves and YTF portfolio that dwarfs anything else globally as an opportunity to access material positions in an emerging area with the additional benefits of proximity to the USA. Overall, in the Mexico round there is a total of 28,500 sq. km. with 2P reserves estimated by PEMEX at 3.8 billion barrels and prospective resources of 14 billion barrels.

Blocks being offered in Mexico's Round 1

Area	*Number of blocks*	*Average size (sq. km)*
Shallow water blocks	**43**	**~300–600**
Deep water blocks Area 1	**11**	**~220–400**
Deep water blocks Area 2	**17**	**~380–960**
Unconventional blocks	**8**	**112**
Onshore conventional blocks	**62**	**120**
Onshore field areas	**28**	**~35–311**

Compared to what is available in the international marketplace, in principle this represents an attractive opportunity. Arguably, the deepwater blocks could be larger in size as well as the unconventional blocks, and some other features could be enhanced.

'MEXICO OFFERS AN ATTRACTIVE PROFILE PROMISING LONG-TERM SUCCESS FOR MAJORS, INDEPENDENTS, AND WELL-CAPITALIZED, OVER-US$500 MILLION START-UPS.'

Summary

Mexico offers an attractive profile promising long-term success for majors, independents, and well-capitalized over-US$500 million start-ups. In addition to capital and capacitation, PEMEX and the regulatory bodies of Mexico are looking for technology-driven approaches to mature fields and underdeveloped field assets. Expert management teams that are able to bring this expertise, along with strong attention to exploration upside, are likely to be successful, as Mexico's mature fields present unique challenges to industry. In today's environment of volatile oil price uncertainties in the Middle East and fluctuations in expectations of the world economy, success factors can be defined broadly as a combination of:

1 Well-qualified management team understanding local processes, cultural sensitivities, regulatory issues, and on the ground challenges.

2 Strong expert technical team with local and relevant international expertise to identify resource and operational improvement potential, in order to capture margin growth and reserves upside.

3 Significant financial backing greater than US$500 million.

4 Early access and scale.

5 Capital discipline.

6 Importance of focus, pure play.

7 Material P1 P2 and P3 reserves in fields available.

8 Material size of acreage, 100–900 sq. km available in exploration blocks.

9 Extensive internally developed drilling inventories.

Mexico downstream: oil reform

Adrián Lajous

The basic design of the Mexican oil industry's new architecture is now in place. Regulatory directives and resolutions, as well as a number of key policy decisions and new business strategies, will further define how the new structures come together. Within this context, it will be the behaviour of the incumbent monopoly, and of new players, that will determine industry dynamics. Public interest in Mexican energy reform has focused on the opening of the upstream to international industry. This is understandable given the expectation of important investment flows and the continuing decline of oil production. However, it is still too early to forecast the magnitude of capital flows associated with Round 1 upstream auctions and farmouts, or the time profile of incremental production and eventual government oil revenues. Recent government medium-term oil revenue projections to 2020 are based on questionable assumptions and unwarranted optimism, even if Round 1 is successful. On the other hand, mid and downstream investments in oil products, natural gas, and electricity could have greater short- and medium-term impacts on Mexico's energy markets and manufacturing industry, and are a central feature of energy reform.

'THE BASIC DESIGN OF THE MEXICAN OIL INDUSTRY'S NEW ARCHITECTURE IS NOW IN PLACE.'

Changes in energy flows

The rapidly changing patterns of energy flows in North America provide a new context that offers significant opportunities, but they are also a source of stress for Mexico and require new policy initiatives and direction. After the dramatic reduction in exportable surpluses of oil liquids that began in 2004, Mexican light crude exports have been displaced by US domestic production, while its heavy crude is beginning to be substituted by the Canadian crudes that have started to flow to the Gulf Coast. As pipeline and rail transport capacity from Canada expands, competition will intensify and Mexican crudes will be redirected to Asia. However, deep conversion refinery capacity expansion in that area will probably lag and be insufficient to process growing Venezuelan and Mexican crude flows.

More interesting for Mexico is the recent growth of gas and oil product imports, mainly from the USA, as this country continues to set production and export records. In the first half of 2014, total Mexican net gas imports were 2.7 bcf/d and oil product imports averaged 600 kb/d. Given domestic capacity constraints, these flows will continue to grow, at least up to 2018. Meeting import demand requires important investments in logistical infrastructure – natural gas and oil liquids pipelines, tank cars, storage capacity, terminals, and transmission and distribution lines. Additional power exports from South Texas utilities are planned for January 2015, based on 1999 US Presidential permits.

Dilemmas faced by policy makers

The effect of expanding upstream production on the Mexican economy is mostly through additional government revenues. The high capital intensity and the high import content of investment that characterize this sector of the oil industry imply the existence of important economic leakages that limit the multiplier effects of capital expenditures.

It is the downstream that has a more direct impact on industrial competitiveness by lowering the supply costs of oil products and natural gas. The same is true of power supply, given the fact that current electricity prices for industry are 75 per cent higher than in the USA. This note poses some of the issues and dilemmas that policy makers face as they introduce greater competition in the oil product and natural gas markets. They will have to offer pragmatic solutions to three prerequisites of competition: infrastructure investment, freeing up oil product and natural gas imports, and competitive pricing. New legislation provides a clear sense of direction and policy has been set regarding these matters. It is in the regulatory sphere and in the actual implementation of market reform where the main challenges now lie. The focus must now be on the multiple transition issues that must be resolved.

'IT IS THE DOWNSTREAM THAT HAS A MORE DIRECT IMPACT ON INDUSTRIAL COMPETITIVENESS BY LOWERING THE SUPPLY COSTS OF OIL PRODUCTS AND NATURAL GAS.'

Mid-stream

Natural gas pipeline construction is booming. Pipelines to the Mexican border from the Waha and Agua Dulce hubs in Texas are being built, interconnections between US and Mexican grids expanded. New trunk lines are being laid along the Northwest Coast and into Central Mexico from the US border. In other parts of the natural gas grid, capacity is expanding, links are being strengthened, and risk-managing redundant capacity installed. Stepwise increases in import

and transport capacity should take place at the beginning of 2015 and 2016. International gas transport companies are involved in construction programmes promoted by the Federal Power Commission (CFE) and PEMEX.

'THE TIMELY COMPLETION, BY 2017, OF THIS VAST NATURAL GAS PIPELINE PROGRAMME IS EXACTING BUT FEASIBLE.'

The excitement surrounding multiple mid-stream natural gas projects contrasts with the lack of drive regarding the much-needed expansion of the liquids logistical infrastructure. Part of the explanation for this lies in the fact that gas pipelines have been opened to private investment since 1995. However, over many years, regulatory failure and inconsistent public policies have prevented the definition of ultimate private and public sector responsibilities for capacity expansion. This resulted in the 2011–12 natural gas supply crisis, when critical alerts signalled multiple gas delivery interruptions. These disruptions triggered a strong investment response directed to the elimination of existing bottlenecks and the building of new capacity. In the case of crude oil and oil product pipelines and liquids storage capacity, institutional, managerial and capital constraints limited the allocation of investment resources. In recent years, product pipeline capacity from the Gulf to Central Mexico has doubled, but a much-needed third product line in this corridor is yet to be built. As oil products can be stored and transported by rail and trucks, supply interruptions were not made apparent and transport cost increases were absorbed by consumers and by PEMEX. Crude transport modernization and capacity expansion was also limited by the lower volume processed in domestic refineries. The propensity of a capital-constrained monopoly to underinvest in infrastructure, both in pipelines and in tank farms, leaves a heavy burden for the liberalization of oil product markets.

The timely completion, by 2017, of this vast natural gas pipeline programme is exacting but feasible. A second, more complex challenge is the establishment and operation of a new regulatory framework and the growth of regulatory institutions – in this case the downstream regulator (CRE) and the competition regulator (CFCE). Their independence must be well protected and respected, and their professional qualifications and capacities well regarded, if they are to maintain credibility – the main asset of regulators. The CRE's experience is basically limited to natural gas. It has little expertise in electricity and none in liquid hydrocarbons, with the exception of LPG. It will have to rapidly recruit and train staff to cope with a widening scope of activities and retain significant consultant manpower, both in technical and in legal matters. Due to the oil industry's de jure monopoly structure, the CFCE has only participated marginally in energy sector issues. It will now have to broaden the range of its mandate, particularly in the oil industry, where multiple competition issues will arise as markets are liberalized.

A third challenge will be the establishment and start-up of the independent system operator (Cenagas), which will be responsible for the national integrated natural gas transport and storage system. This wholly owned State entity was established by law in late August 2014 and a Managing Director has been appointed. It should begin operations in February 2015. The scope of its activities is unique. It is a hybrid that must carry out the functions of an independent system operator (ISO), but it will also be the owner and operator of existing PEMEX gas transport and storage assets. Both PEMEX and CFE will have to transfer all of the capacity reserve contracts that they hold with third-party pipelines. Cenagas is required by statute to separate these two functions operationally and functionally, and keep separate accounts. It will transport the natural gas produced and sold by the PEMEX upstream organization and operate under open access regulations, allocating available capacity through open season procedures. Cenagas will be responsible for daily balancing of the system, developing a secondary market for transport capacity, and for planning the expansion of the natural gas grid. However, it is not an independent body. Four government members and two independent directors serve on its board. Also, requirements for independent directors limit the participation of gas industry executives, important clients, and suppliers with gas business experience.

As a matter of public policy the government decided not to privatize existing PEMEX natural gas pipelines and storage facilities. The Department of Energy (SENER) and the CRE must now design solutions for the development of liquids infrastructure that supports product market liberalization and, at the same time, attracts private investment. A delicate balance between these objectives will have to be skilfully struck, given the constraints imposed by legislation and by existing arrangements. Also, these two organizations urgently need to design the scope and structure of the system operator. The Hydrocarbon Law offers different options to the grids and storage systems currently held by the incumbent. Crude oil and oil product pipelines and storage facilities will be regulated in a different manner to those associated with natural gas.

The existing PEMEX infrastructure will require a permit from CRE to operate under the new legislation. This will most probably be granted subject to CRE

open access and tariff regulations in order to serve third parties. PEMEX would reserve capacity up to a limit set by CRE. There are clear precedents for this as three PEMEX LPG pipelines currently operate in an open access mode. It is likely that oil product pipelines will be legally structured as an integrated system and thus be operated by an independent system operator. Until the CRE declares that effective competitive market conditions prevail, first-hand sales by PEMEX will be regulated, product prices set at refinery gates, gas processing plants, and import points, and invoices will expressly disaggregate the product price from transport and storage costs. This open access, integrated system, operated by an ISO, could adopt one of three different corporate models: (i) a separate PEMEX affiliate; (ii) a wholly owned State agency, similar to Cenagas; and, (iii) a privately owned company with a significant PEMEX minority share.

In the first case, the new company would receive all PEMEX liquid product transport and storage infrastructure and would effectively manage these assets at arm's length, both functionally and operationally, keeping separate accounts with respect to PEMEX and to its responsibility as an ISO. The second option would essentially replicate the previously described Cenagas structure. The third alternative is initially more challenging but offers a cleaner long-term solution. It is closer to the model of the Spanish transport and storage company, CLH, where ownership is highly fragmented among private oil companies, financial institutions, and institutional investors. For example, Repsol only holds 10 per cent of its shares. To illustrate the possible transition to this type of structure in Mexico, one could imagine that the new company would begin by having PEMEX hold 49 per cent of the equity while a Mexican development bank, such as Nafinsa, could hold the remaining 51 per cent. As more capital was required, Nafinsa could sell part of its equity to finance the expansion of the system; PEMEX would eventually follow suit as opportunities arose and better financial conditions could be attained. Also, part of these shares could be placed in the Mexican stock market. This option would not be subject to the institutional and financial constraints of wholly owned state agencies such as Cenagas. Trade union restrictions might also be relaxed if PEMEX holds a minority stake. Analytically, it would not be very different from the envisaged upstream farmouts, where PEMEX would not be the operator. SENER, CRE, and CFCE retain a certain degree of discretion with respect to the actual design of the companies that will be responsible for the liquids infrastructure. They will test a number of variations with respect to the basic designs described.

Both common and contract carriers will expand oil product infrastructure and they will be coordinated by the ISO. Their interconnection and optimization will not be easy tasks. The requirements of storage capacity expansion should not be underestimated as the market is liberalized. Low current levels of oil product inventories pose serious risks and increase transport costs. Growing product imports will also require the development of strategic stocks. Special attention must be given to smaller isolated systems that are more prone to monopolistic practices. These issues will immediately arise in the two extreme ends of the PEMEX grid, the Yucatán and Baja California peninsulas.

The Hydrocarbon Law treats crude oil transport and storage in essentially the same way as oil product infrastructure. However, although it refers to pipelines that gather oil and natural gas from producing fields, it does not establish a clear borderline between gathering and transport pipelines. There is only a passing and awkward reference in the Law to the flow of hydrocarbons within upstream contractual areas, which it excludes from transport systems. The lack of a legal definition poses site-specific problems to new upstream entrants, who will like to know where and under what conditions they can gain access to PEMEX pipelines and storage facilities. Both the upstream and the downstream regulators will have to decide on these matters. In any case, whatever is defined as 'transport' should form an integrated open access system that could be part of both the oil products and natural gas infrastructure or managed separately. Bidders in the Round 1 upstream auction will surely seek clarification.

Competitive markets

The introduction of competition in final product markets has a precisely defined calendar that is included in the Hydrocarbon Law. Starting from a long-established closed commercial monopoly in oil products and partially opened natural gas imports, the transition to competitive markets is being facilitated by domestic price levels that are now close to US Gulf Coast market prices and by a high and growing share of imports in domestic supply. A tight calendar varies by product but the most important changes should have been implemented by early 2018.

'… THE TRANSITION TO COMPETITIVE MARKETS IS BEING FACILITATED BY DOMESTIC PRICE LEVELS THAT ARE NOW CLOSE TO US GULF COAST MARKET PRICES …'

In the case of automotive fuels – gasoline and diesel – domestic prices have been subject to monthly increases in 2013 and 2014, while in some instances US Gulf prices have adjusted downward. The combined effect of these

trends is close to effectively eliminating implicit subsidies that in 2012 were above US$15 billion, the equivalent of 1.3 percentage points of GDP. In 2015 and 2016 the government will set maximum selling prices that will reflect both expected domestic inflation and external market conditions. More important is the decision to transit from a system of uniform national prices to one that gradually reflects transport and distribution costs. As of 1 January 2018 market prices should prevail. PEMEX will continue to be the sole importer of gasoline and diesel until the end of 2016. Import permits to qualified shippers will be granted at the beginning of 2017, when new PEMEX supply contracts will have to allow sales by shippers and service stations that are not part of its current franchise. The restrictions on foreign investment in service stations have now been lifted and the authorities hope to attract private companies to the distribution sector. Multiple problems are bound to arise during this transition. However, the government retains powers to intervene if serious disruptions ensue. There are three issues that must be dealt with: consumer reaction to geographically differentiated pricing, as well as to unplanned price fluctuations and price volatility, and the control of black markets associated with organized crime. The orderly enforcement of ultra-low sulphur diesel and gasoline specifications will have to be adopted by PEMEX in order to meet import competition. PEMEX refineries are lagging in this area, particularly with respect to diesel.

The planned pace of adjustment in LPG markets will be even faster. Mexico's residential LPG market is one of the largest in the world, given the relatively low household penetration of natural gas and electricity. At the end of 2015 import permits will be granted to qualified shippers, but government-set maximum retail prices will prevail until the end of 2016. The current interplay of private Mexican distributors, PEMEX, and consumers is swamped with complex long-unresolved issues and it is not clear at present how they will unravel. Investments by new international players will be allowed, hopefully introducing additional competitors. The government has committed itself to the establishment of focused price subsidies to the poor, both in the countryside and in low-income urban areas, to compensate for rising prices. It understands that LPG is the fuel of choice of Mexican homes, both for cooking and water heating. However, it has yet to design and propose a specific mechanism for the allocation of the new subsidies.

'MEXICO'S RESIDENTIAL LPG MARKET IS ONE OF THE LARGEST IN THE WORLD …'

Natural gas is better placed for further market liberalization. Gas prices have been set monthly on terms related to South Texas pipeline price quotations. These are net-backed to the McAllen/Reynosa border and from there to the large gas processing plants in south-east Mexico – specifically to Ciudad PEMEX, Tabasco – from where they are net-forwarded to all consumption points on the integrated natural gas grid. Some isolated systems, which only connect to US pipelines, have prices that are directly related to price references on the other side of the border. In the last instance practically all natural gas prices in Mexico are linked to Henry Hub spot prices. Regulated prices of first-hand sales in Reynosa and in Ciudad PEMEX have tended to be slightly below Henry Hub prices. Transport tariffs are regulated on a rate-of-return basis and the integrated grid is open access, although capacity constrained.

A large and growing share of the supply of natural gas, automotive fuels, and LPG is provided by imports, which will soon compete with domestically produced supplies. The natural gas supply structure is particularly interesting. In the first half of 2014, net imports contributed 55 per cent of total third-party sales, after deducting PEMEX's own use. In the medium term, this share should continue to expand rapidly. In these circumstances, imports will easily displace domestic production that is not priced competitively. In order to compete, PEMEX will also have to meet certain product specifications. Currently, the nitrogen content of dry gas in south-east Mexico is high and subject to significant variations; this affects costumers' operations. PEMEX will have to solve this problem in order to sell its marketed production without deep price discounts.

The share of imported gasoline and gasoline components reached 54 per cent in 2011. Since then it has slightly contracted due to the on stream entry of the reconfigured Minatitlan refinery and to a fall in domestic demand due to higher prices and slow economic growth. There is no clear evidence as yet that more efficient new vehicles are having a perceptible effect on pool efficiency, given the growth of legal and illegal sales of used automobiles imported from the USA. In the first half of 2014, the import share of gasoline was down to 48 per cent, but it is expected to grow, especially if gasoline demand recovers due to higher rates of economic growth. Only after the three refineries that are to be reconfigured have come back on stream in 2018 and 2019, will the share of imports temporarily fall. Given current and expected refining conditions in the US Gulf Coast, expanding capacity in Mexico does not appear to make economic sense. The market share of domestically produced diesel is bound to fall more rapidly as its demand tends to increase at a higher pace than that of gasoline. A strong economic recovery would thus further accelerate diesel sales and import demand. In the first

half of 2014, diesel imports accounted for 31 per cent of total domestic sales.

The growing product surplus in the USA, driven by the rapid expansion of oil production and falling domestic demand, has a logistically attractive outlet in Mexico. Product can easily flow from the Corpus Christi refineries to northern Mexico and from other Gulf Coast refineries to central Mexico, via Tuxpan, as well as to the Yucatan Peninsula. Imports could be structured under long-term contractual arrangements. The introduction to competition in Mexican product markets might offer further interesting opportunities for US refiners. For Mexico the advantages are obvious: it can place heavy crude with these refiners and buy products at attractive delivered prices in Mexico.

Demand for LPG in Mexico has been stagnant, with a slight downward trend. As the relative price of LPG compared to natural gas and gasoline has narrowed it has been losing market share both in residential and automotive consumption. With full price adjustment to competitive levels, further substitution by natural gas, gasoline, and diesel will reduce the demand for LPG. The speed at which natural gas will displace LPG will also depend on the rate of expansion of local distribution pipeline grids, which will have to overcome opposition by municipal authorities. LPG will increasingly concentrate in geographically isolated markets and rural communities. Given the extension of Mexico's territory, both imports and exports might grow, but net imports will tend to fall. Imports today represent 29 per cent of domestic sales.

Conclusion

Mexico's economic structure is more diversified than that of other oil producing and exporting developing countries. The oil industry contributes only 7 per cent of GDP and manufactured exports represent 81 per cent of total merchandise exports. It is in the realm of public finance where it is more dependent on oil. In the first eight months of 2014, government oil revenues were 28 per cent of total tax revenues. Nevertheless, the size of Mexico's oil product and natural gas markets are significant. In 2013, domestic sales of natural gas reached 7 bcf/d and the corresponding volume of oil products was above 1.8 mb/d. The introduction of competition in these markets, and subjecting PEMEX downstream activities to a harder budget constraint, should provide strong incentives to improve performance. Its refining and marketing assets are poorly managed. In 2013, losses were close to US$10 billion, due to operational, hardware configuration, and infrastructure problems, as well as policy issues. Global refining benchmarking exercises show that, in terms of operational efficiency, PEMEX's refineries remain at the lower limit of the fourth quartile. Clearly, this situation is not sustainable. Natural gas markets are under-supplied in spite of ample North American surpluses, due to pipeline capacity constraints. Market liberalization and ample low-priced supplies of oil products and natural gas in the US Gulf Coast offer attractive opportunities that Mexico must now seize.

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