Energy Journal – Oil & Gas

Perspectives on the Oil & Gas Industry 2018
Building momentum — Oil and gas in Latin America
Development of unconventional oil and gas resources

Local content after a booming oil & gas cycle
Ambitions and limits of local content development

Interview with Patrick Pouyanné, Chairman and CEO, Total
Digitalization can make energy more affordable

Back to Oil!
NOCs & the Indies' agrarian art of production

LNG still in transit
Change continues in the LNG industry, but the pace is evolution, not revolution
Content

E&P cost reduction through systematic technology assessment and roadmapping
A case study in subsea technology identification, roadmapping and aggressive deployment
47

In praise of perpetuity
National oil companies manifesto
52

Dead end approaches for high-sulfur fuels
Refiners’ time window shrinks - they need to act
60

Innovation through contracting in the oil and gas sector
How contracts with external partners drive innovation in the oil and gas sector
73

Beyond carrots and sticks
Unlocking safety gains through understanding irrational behavior
85

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Editorial Board: Stephen Rogers, Dr. Jaap Kalkman, David Borras, Rodolfo Guzman, Daniel Monzon, Yotaro Akamine, Michael Kruse, Ilya Epikhin, and Elias Ghantous
Dear Reader,

In recent months, the rules of the game in the Oil & Gas industry have continued to change, with a shifting of positions across the entire value chain.

Upstream, the traditional East-to-West flow of hydrocarbons continues to slow, driven by increasing efficiencies in North American unconventional oil and gas production, with Latin America now starting to follow suit. US independents comprise almost half of all US production, with their disruptive presence continuing to unsettle the previously harmonious balance between a few large National Oil Companies (NOCs) and the major integrated oil companies. Is OPEC, whilst still immensely influential, still the only price setter? The NOCs now face considerable challenges and a variety of pressures for change, after a prolonged period of low prices. They continue to play a pivotal role in the industry, given their ability to pursue sizeable investments, but they must also address increasing field maturity & complexity which is diminishing the predictability of their sizeable portion of global production. Indeed, to compensate for the production decline in existing fields with new oil & gas, both NOCs and IOCs are going deeper and farther than ever before, as exemplified by the substantial cost reductions that are now anticipated in subsea developments.

Continuing change is also underway in midstream gas, trading & transportation. It is, for example, a pivotal time for the European gas market; new de-bottlenecking infrastructure continues to be built, as well as new import capacity – both LNG terminals and the Nord Stream 2 project. The European gas market is rapidly becoming more and more integrated and efficient, delivering the lowest possible cost gas to consumers across the continent. The LNG industry continues to evolve, with several key disruptions still taking shape; the US moving from LNG importer to LNG exporter, and Japan’s continued effort to replace nuclear electricity production after Fukushima.

Dr. Jaap Kalkman
Managing Partner and Global Head of the Energy & Utilities Practice
Moving downstream, we also see significant change within the refining and petrochemicals industries. The push towards low-sulphur fuel is causing tension between refiners & shippers over marine fuel, while low-sulphur fuel products are also becoming the new norm in petrochemicals. A new petrochemicals investment boom is on the horizon, driven partly by large-scale new projects that integrate refineries and petrochemicals facilities to achieve even higher price differentials and bigger profit margins.

The one constant we see across the Oil & Gas value chain is innovation. Technological advancements - deployed in the right way - are helping tackle operational maturity & complexity, improved contract management solutions are helping to maximize the value of partnerships, safety behavior advancements are helping to improve performance, and local content advancements are helping resource-blessed nations to convert Oil & Gas revenues into local industry prosperity. Of course, digitalization continues to make its mark, moving from being an uncatchable myth to delivering bottom line benefit; in this year’s journal, Patrick Pouyanné, Chairman and CEO of Total, joins us to explain how the fourth-largest major IOC is approaching digital innovation.

Arthur D. Little has a strong track record of supporting Oil & Gas industry players to manage unpredictability and leverage change, at critical stages of their existence. We aspire to be your capability-builder, problem-solver, and agenda-shaper. We trust you will enjoy reading this year’s Oil & Gas journal, and as always, we greatly encourage your views and discussion.

You know where to find us!

Warm regards,

Dr. Jaap Kalkman
Digitalization can make energy more affordable

How the fourth-largest international oil and gas major is approaching digital innovation

An interview with Patrick Pouyanné, Chairman and CEO, Total

Patrick Pouyanné has been chief executive officer of Total since 2014, after the death of his predecessor, Christophe de Margerie, in Moscow. A year after, he became chairman of the board of directors. During his career at Total, he has held several important executive positions in the Upstream segment, both in France and internationally; he also successfully managed the transformation of the Refining & Chemicals segment. In this interview with Arthur D. Little, Patrick Pouyanné examines the upheavals and challenges faced by energy companies, and how Total is embracing digital innovation as a way to drive sustainable and profitable growth.
Many observers have been pointing out the key energy challenges of the coming decades, such as rising energy demand and efforts to limit climate change. How does Total see these challenges?

Total, and energy companies more broadly, are facing a dual challenge. First, the world population is growing. It is forecast to rise from 7 billion today to 9 billion over the next few decades. Today, 1.5 billion people still do not have access to energy. It is fair to say that we must do everything we can to ensure that all these people do have access to energy, a prerequisite for economic development, in 30 or 40 years’ time. And second, fighting climate change is a pressing issue. There is a broad consensus on the objective of limiting the global temperature rise to 2°C, and we fully endorse this aim in our business strategy. At first sight, these two challenges might seem impossible to reconcile. But, in fact, we aim to tackle them both, by being the responsible energy major and providing the world with affordable, reliable, clean energy.

How is Total planning to align with the 2°C roadmap?

The roadmap underpins our strategy and is based on several cornerstones. The first is giving priority to natural gas. We see it as the fossil fuel of the future. It is the fossil fuel that generates the lowest emissions, typically only half as much coal when used for power generation, for example. Our portfolio is gradually shifting from a 50/50 split between oil and gas to a 60/40 split in favor of gas. Gas is also flexible and an ideal partner for renewable energy, which is intermittent, and will remain so until the industry finds a workable solution to store the energy produced by renewables. Promoting gas is a must, which is why, for instance, Total advocates carbon pricing.

“We will still be an oil and gas major in 35 years’ time.”
Does that mean that you still see a long-term role for oil and gas?

Definitely! Have a look at the International Energy Agency’s scenario limiting climate change to 2°C. It anticipates that the energy mix will become less carbon-intensive, but oil and gas will continue to play an important role, accounting for more than 40% of the mix, compared to 60% today. This directly impacts Total: we will still be an oil and gas major in 35 years’ time. Without oil and gas, rising energy demand cannot be met. But as oil consumption will diminish, the most expensive oil will not be produced; therefore, it is important to focus on producing the “low breakeven” oil – in other words, the competitive oil. Strengthening the competitiveness of the oil we produce is what we have done, for example, by pairing Total’s and Maersk Oil’s businesses in the North Sea: we have driven down our breakeven to lower than 30 dollars per barrel, and created the North Sea’s second operator.

But there are other cornerstones, as you said, to reach your objective of being aligned with the 2°C roadmap. You have diversified into renewables, for instance.

I like to see renewables as part of a broader category in our portfolio, which I call “low carbon.” It includes the gas downstream, renewables, typically solar energy, biofuels and energy efficiency. Total has been a pioneer in the low-carbon sector. Acquiring SunPower in 2011 and becoming a major player in solar are part of the same movement as acquiring Lampiris, a green gas and power distributor, and Saft, a high-grade battery maker – as are teaming up with Eren RE, which develops solar, hydro and wind power projects, and investing in CCUS technology. It is aligned with our ambition of growing our low-carbon portfolio to 20% of our business in 20 years’ time. Total is anticipating the changes in the energy mix, which we welcome as an opportunity to grow. But we only invest where we see a business case, and with exactly the same capital discipline as for the rest of our assets. We aim for profitable growth.

So buying Maersk Oil, the Danish oil and gas champion, and partnering with Eren RE, a renewables company, are part of the same strategy?

Absolutely. To invest in low-carbon businesses - some of which are not yet mature in terms of profitability - you need to make money. At Total, our strategy is to fund our diversification ventures through our core business, oil and gas. Diversification only works if you have a solid core business that generates a profit. By acquiring Maersk Oil, we capitalize on our strength, which, in turn, allows us to step up our efforts in renewable energy with Eren, for example. For the same reason, I strongly believe that Total must remain integrated along the oil and gas value
“In my opinion, the energy company of the future should focus on delivering the energy the world needs through a diversified, balanced, profitable portfolio of assets.”

chain, including the downstream. That’s how I see the energy company of the future: focused on delivering the energy the world needs through a diversified, balanced, profitable portfolio of assets.

How has Total approached the changing nature of innovation, for example, the increasing importance of ecosystem development and working with partners, and the need for ever-greater speed and agility?

Innovation is the engine that drives the development of a company and creates its value added in the long term. It is critical for a company like ours to be innovative. Total’s history goes back almost a century, and the fact that we are still here is testament to our ability to develop new concepts and reinvent ourselves. But in an open world, in evolving markets, you can never rest on your laurels. Encouraging a culture of innovation is key to our success. The company now has a culture and an organization that foster innovation, starting with a new Strategy & Innovation Division at the corporate level, which includes R&D and a digital team led by
a chief digital officer. But innovation is not just about products. It is also about the right frame of mind, having an open attitude towards the new challenges that come our way, new work methods and more. This is why I think innovation involves everyone, and everyone is a potential innovator.

How does Total work with start-ups?

We have various interactions with start-ups. Through Total Energy Ventures, our corporate venture fund, we acquire minority interests in those we find the most promising. We gain access to their ideas, agility and creativity, and in return, they have access to our commercial and financial clout. Another example of our open innovation methodology is our “Plant 4.0 project”: every year, we invite start-ups to join this incubator and demonstrate their concepts and

Key facts and figures

- 4th largest international oil company based on market capitalization
- $149.7 billion in revenue in 2016
- $8.3 billion adjusted net income in 2016
- 2.45 million barrels of oil equivalent produced per day in 2016
- 98,000 employees in 130 countries
how they might apply to what we do. I strongly believe that a company like Total needs to be challenged and to keep an open mind about innovation and technology. We cannot come up with all the answers ourselves.

How does Total approach digital innovation in particular?

I like to joke that you can’t digitize oil or gas. They are hard commodities. But what we see happening is that a lot of services related to this business can be digitalized. For instance, we are launching a gas and power distribution service in France that will be available through an online platform. It’s easy, because customers now expect this type of service to be easy. Being digital-based, the service will be very competitive. It’s a great example of how digitalization can make energy more affordable. In the solar business, we are seeing more and more customers being drawn to distributed systems, where a solar panel on their roof is paired with intelligent software, helping them manage their consumption. Digitalization is spreading as our customers are getting more familiar with it. They are starting to expect us to be able to deliver in digital form. So it is really a topic that we are taking seriously. I don’t see it as a threat; I see it as a field offering opportunities.

How does Total see AI, and how does it intend to leverage this new capability and support innovation?

About Total

Total is a global integrated energy producer and provider, a leading international oil and gas company, and a major player in low-carbon energies. Its 98,000 employees are committed to better energy that is safer, cleaner, more efficient, more innovative and accessible to as many people as possible. As a responsible corporate citizen, it focuses on ensuring that its operations in more than 130 countries worldwide consistently deliver economic, social and environmental benefits.
Artificial intelligence is a tool, a means to an end. At Total, we need to acquire and process all kinds of data – from seismic acquisition, or about our customers or the way our plants operate. Processing data is slow and complex, even for Total, which has the industry’s most powerful computer, Pangea. So I believe artificial intelligence, big data management, machine learning, etc., have a role to play there. They are productivity enhancers, that’s for sure. Machines can replicate, accelerate processes. But at Total, a company of scientists and engineers through and through, we will always need the creativity and insight of the human mind.

“Artificial intelligence, big data management and machine learning will play a major role as productivity enhancers.”

Vincent Bamberger
is the Managing Partner in the Paris and Brussels offices of Arthur D. Little.
Back to Oil!

NOCs & the Indies’ agrarian art of production

Back to Oil! is an elegy devoted to the oilman's works and days on the ground, in a world where digitalization makes reality abstract. Excellence comes from the simplicity of concrete gestures and the agrarian rites of oil production. The perpetuity of the National Oil Companies facing maturity depends on the art of cultivating their fields. The American Independent Producers’ operating model, at the historic origin of the Oil & Gas industry, can be in this context a source of inspiration.

“Ladies and gentlemen, I do my own drillin’, and the fellers that work for me are fellers I know. I make it my business to be there and see to their work; I don’t lose my tools in the hole, and spend months a-fishin’; I don’t botch the cementin’ off, and let water not the hole, and ruin the whole lease. And let me tell, I’m fixed right now like no other man or company in this field. Because my Lobos River well has jist come in, I got a string of tools all ready to put to work. I can load a rig onto trucks, and have them here in a week. I’ve got business connections, so I can get the lumber for the derrick – such things go by friendship, in a rush like this. That’s why I can guarantee to start drillin’, and put up the cash to back my word. I assure you whatever the others promise to do, when it comes to the showdown, they won’t be there.”

Oil! Upton SINCLAIR, 1926

Hydrocarbon nationalisation in the second half of the twentieth century merged private operators to create a State-owned monopoly in charge of domestic Oil & Gas production. Hydrocarbon nationalisation gave the State control of giant petroleum fields marking the rise of National Oil Companies. Hydrocarbon nationalisation happened at the eruptive stage of reservoir developments.

However, after fifty years of operations, most of these reservoirs are today in decline; National Oil Companies are looking for a new model to manage the maturity of their assets and the renewal of their resources. Reservoir management has become more complex; water injection floods field areas, with increasing water-cut and gas volumes indicating rapidly advancing field maturity. Generally, these issues require an upgrading of treatment facilities. The major, founding fields have matured as National Oil Companies age, usually resisting their inevitable production decline through secondary and tertiary recovery programs.

Nevertheless, in spite of all the clear signs of maturity, regulatory authorities continue to demand an increase in production rates, citing State budget requirements. Annual production forecasts and middle & long-term strategies together form a theatre where Regulatory Authorities confront NOCs to politically reformulate operational constraints, choreographing a balance of power that shapes, over time, the behaviour of reservoirs towards their extinction. NOCs’ perpetuity depends on a moving point of equilibrium between political directions and operating conditions. The fate of Indonesia, a crude importer since the 2000s, illustrates the fall of a significant oil power at the birth of production sharing contracts, due to political pressures prevailing over industrial reason. Hydrocarbon nationalisation has fostered the creation of monopolies, producing new oil & gas that is increasingly difficult to extract, especially for organisations perceived as bureaucratic anachronisms driven by political directives. National Oil Companies will live as long as their fields; a life cycle affected by national agenda ambitions.

1 In praise of perpetuity, National Oil Companies Manifesto, Alexandre Lavelle, September 2017
and governance models that intertwine Regulatory Bodies and operators. Nationalised production is currently at the end of a cycle. Reforms in Mexico, revised hydrocarbon laws in Algeria, and enhanced service agreements with international operators in Kuwait are all trying to create alternatives, or at least to defer, the obsolescence of a fifty-year-old nationalisation model.

What to do? What to do? Ask the leaders of national monopolies at the asymptote.

How to perpetuate national revenue from the petroleum industry? Consultants and symbolic analysts have all proposed the privatisation of production, the optimisation of existing resources, or the introduction of commercial performance criteria that question State-owned companies’ raison d’être. But, do such measures value the historic mandate of National Oil Companies as industrial champions, safeguarding their existence and the development of their nations? What to do? What to do? Ask the leaders of national monopolies at the asymptote. Do they try to reverse their company’s decline in the form of an energy transition? Some, ground down by the national agenda double-bind, would rather separate state imperatives and industrial necessities to protect the conduct of operations from any political intrusion. This secularisation trivialises the importance of the National Oil Companies, transforming them into common actors on the stage of international competition. Such change, in favour of strict economic performance, underestimates the role they play in their respective national economies.

The investments that National Oil Companies have continued to make in the Middle East, despite the last five years’ unprecedented crisis, have reinforced their place in the oil ecosystem. NOCs have provided the framework within which the recent confrontation with American independent producers has taken place. Today, national operators asymmetrically face a myriad of competitors in Texas, Oklahoma or Colorado, all of whom have benefited from the shale oil & gas revolution by focusing on short-term profit goals, far from the constraints of regulation or international institutions.

The competitive landscape is changing: IOC now present themselves to State monopolies as partners in the energy transition and as new technology providers for knowledge transfer. In this manner, they encroach upon the traditional businesses of service companies, who in turn respond by being ready to invest in integrated operatorship. This new competitive asymmetry should be a source of learning and innovation for National Oil Companies, who are more accustomed to binary

logic (International operators versus national operators) and not to the fast-changing dynamics of much more agile actors.

“These wells are my fruit trees!”

In 2015, US independent producers represented 54% of domestic crude oil production and more than 85% of domestic gas production. Their development plans accounted for 90% of the wells drilled in the US. Independent companies are businesses, often family-owned or with a narrow shareholder base, that are focused on the exploration & production of hydrocarbons. From Alaska to the Gulf of Mexico, whether specialised in secondary recovery for mature fields or driving drilling factories on shale gas sweet spots, they testify to American supremacy in the Oil & Gas sector.

Speaking at a conference sponsored by America’s Independent Oil & Gas Producers in 2017, Melville Poe, an owner of twenty-seven wells in Wyoming with a combined daily output of 5,900 barrels, laid out the golden rules of an American producer. “In 2007 I received nineteen producing wells, as an inheritance from my father. Some of my wells are still in operation after thirty years of activity. After two thwarted attempts in 2009, I successfully drilled eight new wells in the Ordovician layer. These wells are my fruit trees; I inspect them every day and test them every month, just as my father did all his life. I still respect the five golden rules he taught me: 1) Each well is a profit-and-loss account and is to be considered as a business, 2) Time is money, 3) Optimise any type of service company intervention by managing them with rigor, 4) Chronicle the memory of a well from birth, 5) In case of discrepancy, decide on the spot.” For Melville Poe, producing is first and foremost a matter of looking after the wells, just as an arborist would, over the seasons, place his hand on the bark of his trees. A producer ages with his field, on a continuous learning curve from drilling to last oil.

Wyoming’s oilman reminds me of the production engineer I knew at Sonatrach from Tin Fouyé-Tabankort; he used to go out every week in the desert of Illiz to raise the Barton chart of his wells, scattered over tens of kilometers. These two men, listening to specific wells, practice the same profession; linked by the deep geology of the Ordovician layer. They devote their entire lives to the same field, and over decades, their daily work has shaped the operating conditions and the surrounding landscape, streaking it with truck tracks. Their community of practice resides here, in clear contrast with IOC expatriate rotating assignments that migrate from one country to the next, usually after only a few years on a field.

2 See the Work of Nations by Robert R. Reich, 1992
3 See https://www.ipaa.org
4 The definition given by the Independent Petroleum Association of America is: “The U.S. Internal Revenue Code section 613A(d) defines an independent producer as a producer who does not have more than $5 million in retail sales of oil and gas in a year or who does not refine more than an average of 75,000 barrels per day of crude oil during a given year. There are about 9,000 independent oil and natural gas producers in the United States. These companies operate in 33 states and the offshore and employ an average of just ‘12 people.’” https://www.ipaa.org/independent-producers
The Indies’ roots of production excellence

It was only once the 2014 oil price crisis had hit that OPEC (re)discovered how American independent producers could maintain, and even increase their level of production despite the price freefall and a backdrop of complex operating conditions. Some went bankrupt, but others resisted and capitalised on the shale oil revolution. Driven by an ancestral sense of entrepreneurship worthy of the oil industry’s early days in Oklahoma or California, American producers drastically optimised their operating costs and steepened their learning curve. They revised their E&P operating model, restoring the global reach of the US hydrocarbon school built around wells management and operations excellence. Their firm control on operations, performed with a flexibility that accounts for the smallest reservoir signals, should be a source of inspiration for National Oil Companies who have been inclined to admire the perceived excellence of IOCs and their processes. New technologies are certainly decisive in improving the recovery of mature fields, but they will never replace the practical day-to-day intelligence of a field operator in well maintenance, rigorously testing his or her equipment and production flows.

The drop in oil prices fueled a return to prominence of independent companies to the United States, where they focused on optimising operating costs and strengthening their learning curve. Thanks to the flexibility of their business conditions, the service company ecosystem, and the availability of oil & gas infrastructures in Texas, Colorado, or Oklahoma, they have freed themselves from the regulatory and industrial obligations that plagued their activities in Asia or the Middle East. By focusing on well performance, they have been able to achieve unprecedented excellence in operations, inventing the “drilling factory” that lies at the heart of the shale oil & gas revolution. Independents have become, in the last ten years, a source of innovation; not in the development of new technologies - the traditional levers of IOCs and their service company competitors - but in terms of know-how and operational control. They have perfected the industrial organisation of their production.

NOCs’ mature fields – a greenhouse for the Indies?

Most of the fields that started producing during nationalisation are now mature or in decline. If hydrocarbon nationalisation had happened today in Algeria or Kuwait, it would be much more complex to implement because of the multitude of factors and issues to integrate and control. Production from Hassi Messaoud or Burgan, for example, now depends on increasingly complex partnerships, both in terms of technology requirements and in terms of the distribution of roles and responsibilities, in a web of regulatory, technical, cultural, and commercial factors. When IOCs negotiate their own service contract offering, they propose proprietary technologies deployed to leverage petro-technical data obtained from NOCs. This creates complex situations that border on a conflict of interest. IOCs and service companies are now in direct competition: relations are blurred, conflicts fester, and misunderstandings accumulate, exposing the obsolescence of contractual schemes that are not adapted to current national agendas.

National Oil Companies would undoubtedly benefit from a wholesale review of their partnership strategy to consider specialised operators, for example in managing mature fields or exploring unconventional resources. These specialised operators are independent players renowned for their risk management model (at the heart of their core business), their unique technical skills related to the nature of their portfolio, and their pragmatism. They are E&P companies that buy their technologies on the market, focusing on the profitability of their investments, the performance of their projects, and the efficiency of their operations. They favor technical impact over political influence. Their industrial culture and modus operandi could be, in this context, an interesting experience for NOCs looking at alternatives to the competition between IOCs and service companies. These specialised operators do not have the scale of the majors and will not be the international champions to lead an energy transition, but they have acquired operating know-how at the source of operational excellence. The challenge for producing nations should now be to offer these operators sufficiently attractive conditions that are adapted to their model: regulatory and fiscal stability, advantageous remuneration for the exploration risk or the production optimisation, and a clear scope of intervention defined around limited but precise objectives, protecting operations from any form of politically-driven intrusion.

Such partnerships require contractual creativity, developed outside the usual E&P license framework. For example, pilot projects could be designed to manage production masterplans for five-year periods; a form of delegated management entrusting a paid operator based on production impact. This delegated management of an asset on a controlled scale - between fifty and one hundred wells - would put a field and its industrial chain into an incubator, generating best production practices from reservoir to tank. The ultimate objective would be for the National Oil Company to entrust the complete conduct of its operations in this manner without renouncing its sovereignty. It would still be responsible for investments and would remain the owner of production, rewarding the operator-partner according to a predefined mechanism based on the level of production, thus respecting the legislative framework. The operator would manage the field, developing the workforce of the National Oil Company without resorting to proprietary technologies or practices, as an IOC or service company would.
A partnership between a National Oil Company and an independent operator could certainly generate significant tensions, due to the asymmetries and differences in industrial practices, opposing managerial cultures and the independents’ real-time management approach that contradicts the budgetary cycle of a State monopoly. However, such a contractual framework must protect the *raison d’être* of the delegated operations scheme, which is to restore the *savoir-faire* of the independent operator on the ground, with all the technical perfection that it implies. The National Oil Company can thus restore the production engineer’s original intelligence, and rid themselves of unnecessary artefacts and filters, new commercial technologies, screens and standards, all of which skew the practical knowledge of the field. The return to essential actions - reducing the flow of a gas compressor, driving a scraper through a pipe, forcing the flow of crude oil through an online regulator at the separator, ... - improves real operations performance, from the realisation of tests to the calculation of forecasts.

E&P taps into time worked on the rock. Oil is an industry of memory; it explores organic deposits within stratigraphic structures accumulated over millions over years, sheltered in folds of geological eras. It deciphers a landscape and its outcrops by erecting infrastructures that age with the fields beneath them. Facilities interrogate and conserve the measurements generated during operations, analysing conditions over time to enhance the extraction of oil and gas. The development of new technologies, since the first wells in Pennsylvania, has not replaced the practical expertise of operators carved by the geology of mother rock and forged in steel mills. The operator’s hand monitoring his wells is one of the sources of his operational excellence. *Back to Oil!* is a call to National Companies to perpetuate the agrarian art of oil production, unearthing the geological memory of the landscape and the industrial engineering of man in his first gesture: reaping the fruits of his labour.

**Authors**
Alexandre Lavelle, Elias Ghantous, and Yousef Al-Jarrah

www.adl.com/BackToOil!
LNG still in transit

Change continues in the LNG industry, but the pace is evolution, not revolution

The LNG industry finds itself today in a very different situation than was expected 10 years ago. Several key disruptions have occurred: shale gas turned the US from an LNG importer into an LNG exporter, imports to Japan boomed to replace nuclear electricity production after Fukushima, and European gas demand collapsed due to the combined effects of the global recession and cheap coal. There are new types of players in the market, spot-trading volumes have increased, and global prices have converged. But much remains the same. In a business characterized by large, long-term capital investments, the pace of change has historically been slow. In our last LNG update two years ago, we highlighted that the industry was in a period of transformation towards liquid trading markets; here, we review the current picture and outlook, as well as implications for market participants.

Overview of recent history

Global LNG price convergence has long been considered likely. In theory, trading should eliminate regional price differences (other than logistics costs) and make a more efficient market in which supply, demand and transport costs determine LNG prices and flows.

It would be easy to conclude that the disruptive events of recent years were the cause of global price convergence. Oil indexation is still dominant in LNG purchasing: over 75 percent of LNG volumes imported globally in 2016 were indexed to oil. And lower oil prices explain a large proportion of the observed price convergence. The Asia-Pacific region is the global center of LNG demand, as well as for oil-indexed buying. Price convergence has been apparent since 2015, coinciding with the trend in oil prices. The Henry Hub LNG price (typically spot price plus variable fee at 115 percent Henry Hub price, plus fixed fee at around 3.00 $/MMBtu) has become higher than both the Japanese import spot and long-term oil-indexed price. If we include transport and regasification at around 2.00 $/MMBtu, US exports have not been attractive to Asia-Pacific buyers through 2017.

LNG & Crude oil prices, 2010-2017

Source: PAJ, METI, EIA, IMF
The high-price, high-demand period 2011–2014 led to a large amount of liquefaction capacity coming forward for development. This has led to global over-supply of LNG and a “buyers’ market,” with buyers wanting to take advantage by negotiating lower prices for LNG. A “lower for longer” oil price outlook has reduced this pressure, though Indian buyers in particular have publicized their recent successful renegotiations of indexation slopes in LNG contracts that had been signed only a few years ago. Slopes of around 14.5 percent have been typical in Asia, but have been reduced to around 12.5 percent; new contracts are reported with slopes below 12 percent.

Buyers have also used the arrival of US exports as a bargaining tool. Typically, US contracts are linked to Henry Hub prices, not oil. Buyers are thereby diversifying risk by concluding contracts based on different indices or combining them.

The increase in Asian LNG demand triggered a step-change in trading outside long-term deals, from less than 20 percent of global volumes in 2009 to around 30 percent. The “pure” spot part of this trade, for delivery within three months, has grown in recent years. This is largely through diversion of cargoes and reloading for sale in another location, and represents buyers dealing with surplus LNG within long-term contracts, rather than LNG producers actively seeking spot sales.

There is generally an abundance of LNG vessels, which were ordered during the period of high prices. Therefore, transport for spot cargoes should be readily available and cheap ($20,000/d in 2016, compared to $150,000/d in 2012), thus supporting growth in spot trading. But there is a lack of available vessels in the Atlantic Basin moving into winter 2017. Charter rates here have risen above $50,000 per day as buyers seek to reload and send cargoes to Asia for LNG prices at a 3.00 $/MMBtu premium to TTF. The lead time for vessel programming continues to be a barrier to the development of LNG trading.

Outlook

In summary, despite some price convergence driven by lower oil prices, there has been no dramatic shift to a single new pricing model. Several pricing and contracting methods co-exist. We are still in transition, with several key themes emerging:

Buyers’ market – for how long?

The supply overhang looks set to continue to at least 2020, based on liquefaction projects currently in construction. Beyond this point, there are many uncertainties. Future demand growth seems likely to be led by Asian markets, in particular China, Japan and South Korea; policy decisions will play a big role in influencing the scale. Regional LNG consumption forecasts feature a high/low range of 100 bcm/yr in the early 2020s. Government plans for environment and power sectors currently appear to favor gas over coal and nuclear. For China, the future role of LNG in total gas demand is unclear: the mix will also include Russian pipeline gas and domestic production.

On the supply side, there are enough proposed and planned liquefaction projects globally almost to double existing capacity. But current prices do not justify investment in new projects, and the additional LNG is not needed. Several major projects have already been cancelled in the last two years, reflecting the change in project economics and suggesting that supply/demand are already realigning. Counter to this, the world’s largest exporter, Qatar, announced in July 2017 its intention to increase exports by 30 percent by 2024 (from 95 bcm/yr to 135 bcm/yr). Politics and the desire to protect market share can drive decisions, as with crude oil.

Buying, selling, pricing

- Oil indexation

Security of supply remains the priority for many buyers, and tends to lead to a conservative approach to purchasing. While there is a clear trend towards developing portfolios of varying contract duration and indexation type, changes in the contracting mix will take time. JERA, the largest LNG buyer, plans to reduce long-term oil linkage from more than 80 percent to half of its portfolio over the next decade. It has also developed trading and risk management capability. Sellers still value long-term contracts as a means to secure financing, which seems unlikely to change.

It is likely we will see co-existence of historical contracts with new 5 to 15 year deals based on non-oil and hybrid indexation (hubs, LNG indices, oil, power), along with short-term trades, including buyer-driven tenders for up to five years of supply.

![2016 LNG imports by region and pricing method](chart)

Source: IGU, ADL

- Trading hubs

The creation of regional trading hubs in Asia has been discussed for many years. The aim is to provide a reliable physical price marker, which could serve as an index for financial trades.
Several potential locations and indices have been proposed by governments, stock exchanges and price reporters (Argus, Platts). Singapore is already the location of the energy trading offices of regional and international players, and has a facilitative regulatory and legislative environment. But low physical LNG demand and lack of infrastructure are barriers to development of physical trade. The SLInG price index is an FOB assessment of vessels on the water in the vicinity of Singapore. Japan, Korea and China are in contention as the physical DES hub. Levels of liquidity are hard to assess, as much of the trading takes place bilaterally. It is clear that no single hub has truly emerged as the regional marker – and that will not necessarily be the final outcome.

The current situation of over-supply should encourage further trading. But for buyers, the low-price environment means there is less incentive to push for gas-related pricing through establishing trading hubs. With around 10 hubs and markers, critical mass of trading may not occur at any single hub. Standardization of quality, infrastructure access and regulation are barriers that have not yet been overcome.

Liberalization of gas and electricity end-user markets in Japan could be a catalyst for change. Utilities will no longer have the right to pass through the cost of fuels, and there will be competition for consumers. This will mean that prices and volumes downstream are no longer secure, and therefore the need for risk management and trading should increase. Japan’s Fair Trade Commission’s decision to outlaw destination clauses on new contracts should also help stimulate trade.

Gas hubs elsewhere have formed at pipeline interconnections. The US Henry Hub is where multiple pipelines connect, the NBP in the UK connects upstream and downstream gas at no specific location within the national pipeline system. So far the Asian regional LNG price markers are located at points of import.

Sustainable LNG trading hubs could form at the production and export regions, i.e. for FOB rather than DES contracts. This would allow the standardization of gas quality and, by excluding transportation costs, make a regional standard product. The global coal market operates in this way, using, e.g. FOB Richards Bay as the South African coal-export price marker. LNG traders already think in these terms when calculating arbitrage opportunities. FOB West Africa and FOB Gulf of Mexico are potential LNG examples. In the coal market, price markers for imports also exist (e.g. CIF ARA), suggesting there might also be room for Asian DES hubs for LNG.

- Contracting

Contract bargains are complex and incorporate many types of risk, including price, volume, counter-party credit and non-performance. Both buyers and sellers need to understand the risks involved, their risk appetite and their risk management capabilities. As the LNG industry evolves, so will approaches to contracting. Signing a long-term contract is often perceived as low risk, but may actually be the opposite, because the market and counter-party conditions at signature may evolve adversely over the tenor of the contract. Back-to-back contracting can mitigate risk, signing downstream agreements (for sale of gas, heat or power) simultaneously with upstream deals to lock in a certain margin. But the margin and the match of the buy/sell may not be satisfactory. Identifying, monitoring and managing exposure is required.

Players

“Aggregators” and commodity traders have become key players in the last decade. Aggregators (e.g. Shell, BP, Total) exploit arbitrage between regions by holding many global-capacity positions and vessels. Pre-2014, they used these to derive consistently high margins. The trading houses (e.g. Trafigura, Gunvor, Glencore, Vitol) entered the market by taking short-term positions, picking up excess supply and reselling it on the spot market. They have started to engage in longer-term activities such as financing and off-taking from FSRUs to open up new markets.

If JERA, KOGAS and CNOOC form a buying consortium as reported in the press, one-third of global LNG purchases will be handled in the same group. The “buyer-aggregator” swap opportunities from this are clear. But will the level of market power be tolerated by regulators? For smaller buyers in the region, buying groups are also feasible. The development of trading and hub prices based on local supply and demand signals should bring opportunities for them. The use of third-party risk manager or optimizer services may be preferable for the small utility, rather than trading themselves. As more non-physical players enter the market, we can expect opportunities to collaborate or create joint-ventures, and transfer knowledge.
Infrastructure

In an LNG market with spot, oil and hub-index pricing, each of which may give different price signals, efficient and timely infrastructure development may be problematic. Spot prices should indicate the need for additional supply, but signals may be short lived and localized. The lead time and scale of investment required for typical new LNG projects add to the complexity. Large buyers have taken equity positions in liquefaction plants for several years, and this seems likely to continue, combined with portfolio diversification. Given the uncertainties described, lower-cost, smaller projects are more likely to progress in the short term. Floating liquefaction and small-scale LNG are more attractive to investment funds, private equity and the big trading merchants, and returns can be realized sooner.

Conclusion

Major changes are occurring in the LNG industry, but there has been no overnight transformation. In an LNG market in ongoing transition, Arthur D. Little helps players to:

- Anticipate change in the balance of power in the market through scenarios for LNG supply/demand and pricing, and to understand the signposts and pivot points for change.
- Innovate contracting methods and terms, purchasing portfolios and business models.
- Transform operations and capabilities better to understand and manage risk.

Authors

Kirsty Ingham and Yvonne Fuller
Building momentum – Oil and gas in Latin America

Executive Summary

Unconventional oil production has grown these past few years despite low oil prices since 2014. Although production in the US decreased in 2015, stabilization of prices and improvements in several operational areas allowed unconventionals to maintain a relevant role in the global supply. Last year, Arthur D. Little published a viewpoint analyzing the perspectives for unconventional resources in selected Latin American countries. While our outlook for Latin American opportunities remains positive, there are new factors to consider. The key shale players have stayed strongly focused on the US, the moderate oil price recovery expectations persist, and concerns about fracking operations are increasing. Therefore, host countries, especially in Latin America, are now under greater pressure to create conditions that favor the development of these resources.

In recent years, countries such as Mexico, Colombia and Chile with potential in unconventional hydrocarbons have been evaluating their prospective resources. However, these activities have not been enough to build momentum and attract resources to speed up the de-risking process for unconventional hydrocarbons. Building momentum requires a strategy for aligning technical, regulatory, and economic conditions to boost the de-risking process of the greenfield plays prior to the take-off of massive developments. Two major forces can, in our opinion, help build momentum: national oil company leadership and/or government promotion & incentives. Besides these levers, a deeper understanding of the local conditions of the oil & gas industry is fundamental for defining the strategy and tactics for building momentum.

In our view, the development of unconventional hydrocarbons in different geographies will continue shaping the global oil and natural gas markets. Countries with high potential and interest in expanding their production, such as Mexico, Colombia, and Chile, still need to build momentum to ensure the inflow of capital investments to speed up the exploration/evaluation phases. Although there is still uncertainty regarding the feasibility of large developments, the growing demand for hydrocarbons presents an opportunity for oil companies.

As the energy industry continues evolving, trends in supply and demand could change the incentives to develop the unconventional plays (growing share of renewable, peak of oil demand, etc.). Therefore, there is a closing window of opportunity for adopting a strategy to provide the required support to oil & gas players and take advantage of unconventional developments.
1. Introduction

Unconventional oil production has grown these past few years despite low oil prices since 2014. Although production in the US decreased in 2015, stabilization of prices and improvements in several operational areas allowed unconventionals to maintain a relevant role in the global supply, adding more than one mboed in 2017.

The oil and gas industry downturn forced oil companies to change their production strategies in order to mitigate the negative impact on their financial results. Most of the companies, including Majors, withdrew or delayed costly long-term projects to focus on opportunities that offered shorter development cycles and lower investment requirements. Among the latter type of opportunities were many unconventional developments in North America.

In this scenario, the Permian Basin positioned itself as the “sweet spot” of the US unconventional oil and gas developments. Attractive economics are the result of privileged geology that features multiple stacked plays – more than 1,000 feet thick each – and could hold vast reserves. The existing infrastructure and minimal needs for equipment displacement due to the stacked plays have decreased the break-even price significantly. Nowadays, this play is the largest producer of liquid hydrocarbons and the second-largest producer of natural gas in the United States. Permian has attracted investment from several Major oil companies, such as Chevron and ExxonMobil, as well as independents such as Pioneer and EOG. The increasing attention to domestic shale opportunities has resulted in lower levels of international activity for North American companies.

The fast-paced investment activity in the Permian Basin for asset transactions in 2017 reached more than 45 deals altogether, amounting close to USD 23 billion. Due to its success and relatively low risks, this world-class shale play has set expectations at too a high level, making it more difficult for overseas shale opportunities to attract international investors. Although several countries have confirmed their potential for unconventional production, development has not progressed at the same pace as it did in the United States, which offered the perfect ecosystem for shale development: prolific shales, light regulation, shale in sparsely populated areas with few environmental issues, water availability, multiple service providers and preexisting infrastructure. It will require a lot of effort for host countries with shale opportunities to achieve competitive conditions similar to those offered by the key US shale basins. National and local authorities, together with domestic industry participants such as NOCs, will play a key role in building the proper conditions for such developments to materialize.

In 2017, Arthur D. Little published a viewpoint analyzing the perspectives for unconventional resources in selected Latin American countries and the challenges those countries faced to stimulate these types of developments. While our outlook for Latin American opportunities remains positive, there are new factors to consider. The key shale players have stayed strongly focused on the US, the moderate oil price recovery expectations persist, and concerns about fracking operations are increasing in many places. Therefore, host countries, especially in Latin America, are now under greater pressure to create conditions that significantly favor the development of these resources.
Key improvements in unconventional operations

The US unconventional industry was able to maintain its growing production trend, aided by operational and technical improvements in a variety of areas:

- **Targeting**: Multiple methods have been developed to optimize the positioning of a horizontal wellbore in order to maximize reservoir exposure. Well placement success is often associated with the technologies of geosteering, which have been recently improved with the use of 3D seismic and real-time monitoring tools. These tools allow for timely reactions in order to best navigate the most prospective horizons.

- **Drilling and completion**: Drilling technologies are always evolving from play to play and adapting to the specific conditions of each formation; therefore, the improvements in drilling vary by play and even within the same play. Some of the most important efficiency breakthroughs include increased length of laterals, the ability to drill multilaterals to allow access to multiple zones and reduce costs, multi-pad drilling to optimize the use of space, pad drilling with hydraulic walking or skidding systems to optimize rigs movement, and improvement of reservoir characterization and completion techniques to allow differentiated treatments of fractures by well and by stage.

- **Logistics and operations**: Centralized developments have improved the economics and logistics of the drilling site by reducing the surface impact and traffic for operations, as well as through concentration of facilities, compressors, tanks, separators, etc. This also results in smaller requirements for pipelines and access roads. Some players have also been acquiring specialized services companies integrating own sand and equipment to ensure competitive supplies for the operations.

- **Well productivity**: There have been many efforts to improve well productivity in different shale plays. The best-known innovations are in the area of artificial lift systems that help to maximize recovery, reduce costs and increase pumps’ life and efficiency. A few operators have also adopted new techniques to improve productivity, such as EOR methods using gas injection. This method has been pioneered by EOG Resources for the Eagle Ford and it has been tested in the Bakken with positive results, however there is still more testing to do to prove the benefits of EOR in shale.

- **Digital technologies**: The use of “big data” approaches combined with powerful software has played a key role in the optimization of E&P operations, especially for improving the identification of sweet spots. The industry shift to improve efficiency with data crunching and predictive analytics allows for significant reductions in cost and uncertainty.
2. How to create momentum for unconventional developments in new countries?

In recent years, most of the countries with potential in unconventional hydrocarbons have been evaluating the resource potential in prospective areas and, in some cases, drilling a few wells to validate the different characterization models. However, these activities have not been enough to build momentum and attract resources to speed up the assessment and development of unconventional hydrocarbons.

Building momentum requires a strategy for aligning technical, regulatory, and economic conditions to speed up the process of evaluation and confirmation of the commercial and technical feasibility prior to the take-off of massive developments. Two major forces can, in our opinion, help build momentum:

National oil company leadership
The national oil company could take the lead, assuming the role of “starter engine” to attract other players looking for unconventional opportunities. The NOC is usually best positioned to naturally become the pioneer in its own country’s shale plays due to its geological knowledge of the basins, its first-hand information to evaluate the prospective areas, its pre-existing relationship with the country’s regulators, its mission to follow national strategic initiatives, its close involvement with the communities. Therefore, the NOC can become the first mover and a key player in de-risking the unconventional plays.

Government promotion & incentives
The authorities can create the conditions to improve the sector’s attractiveness. Providing incentives to attract the most experienced companies, adjusting the fiscal and contractual terms to improve the risk-reward value proposition, and working with local stakeholders and communities to demystify beliefs about the negative impact of fracking operations, are some of the most critical steps to build momentum.

Besides these levers, which might in essence seem very simple, a deeper understanding of the local conditions of the oil & gas industry is fundamental for defining the strategy and tactics for building momentum in a particular country. Specific regulations, investment climate, domestic market factors and local context have resulted in varied paces of progress in unconventional resource development around the world. Only a few countries have been able to build momentum and move forward from the early stages of evaluation and piloting to massive commercial developments. Outstanding examples are Argentina, China and Canada, as we describe hereafter:

Argentina
So far, Argentina is the only Latin American country in which unconventional production has reached commercial scale, though it is still small relative to its potential. Argentina has been successful in building momentum because YPF, the NOC, took a leading role in investing to improve the knowledge and characterization of the Vaca Muerta formation. Key accomplishments of YPF with the support of the government include:

- Acquired extensive knowledge and proved the concept of development in the basin by investing more than 6 billion USD
- Drilled nearly 700 unconventional wells in different blocks
- Adopted a strategy to build alliances with several international players
- Developed pilots with extended production tests to demonstrate technical and economic feasibility

In addition, the government, at both national and local levels, has strongly supported the industry by:

- Maintaining higher domestic prices for unconventional gas developments
- Facilitating the process for licensing the unconventional prospective areas through reclassification of former conventional licenses, provincial bidding rounds, direct negotiations, and facilitating transactions in the traditionally active secondary market of petroleum interests
- Promoting infrastructure projects to facilitate project developments
Furthermore, the growing supply-demand gaps in the Argentine oil and, particularly, natural gas markets have provided additional life-cycle incentives for investors and producers. Argentina reached total unconventional production of 80 kboepd in 2017, which represents accumulated growth of 33 percent from the 2015 level. (See figure 1)

Figure 1: Argentina’s activity in unconventional developments

Source: Rystad, IGG, IGGe, Arthur D. Little Analysis
China

China’s first shale gas commercial production program was launched in 2014 in the Fuling field operated by Sinopec, which is one of the largest state-owned oil and gas companies worldwide. Currently, China ranks as the world’s third-largest shale gas producer, with production of approximately 10 Bcm (353 Bcf) in 2017, and this is expected to keep growing.

Figure 2: China’s activity in unconventional developments

![Graph showing China production and unconventional production](image)

![Graph showing investment in unconventional projects](image)

Source: Rystad, Arthur D. Little Analysis.
China has been successful in building momentum because the NOCs, mainly Sinopec and PetroChina, took a leading role in investing to improve the knowledge and characterization of their domestic basins. Key accomplishments include:

- Developing a strategy to acquire know-how. China’s national oil companies have been investing aggressively in the United States to acquire shale acreage, and this has allowed for an accelerated learning curve. For example, Sinopec paid USD 1 billion for properties owned by Chesapeake Energy, one of the US pioneers in shale gas development.

- Acquisition of knowledge and proving the concept of development in domestic basins by investing more than USD 5 billion.

- Drilling more than 600 unconventional wells in different domestic basins.

- The Chinese authorities have strongly supported the industry by:
  - Providing production subsidies up to 2020
  - Providing waivers of price controls and fees
  - Granting tax concessions, committing research funds, and promoting price reforms.

Furthermore, the growing demand for natural gas and increasing imports by pipeline and LNG are positive signals to investors that foresee a secure market for shale production.

It is fair to point out that there is still some skepticism around China’s ability to keep up with unconventional developments. The main challenges are related to water availability, complex geology of the formations, and lack of adequate infrastructure, which will affect the economics of the operations.

Canada

Canada is the second largest producer of unconventional hydrocarbons globally. In 2017 the production of shale reservoirs reached 170 mbpd of oil and 10,400 Mpcd of natural gas. (See Figure 3.) The Duvernay and Montney formations in Alberta and British Columbia have attracted the attention of national and international oil companies.

While Argentina and China have developed unconventional hydrocarbons under the leadership of their NOCs, Canada adopted a different strategy led by the government, which was concerned about the declining investments in oil sands projects. The strategy included enhancing the technical information base, flexibilizing fiscal terms, and simplifying the regulatory framework for permits. Some of the key adjustments included:

- The government keeps records of the different technologies applied to drilled unconventional wells and their results, to be shared with potential investors.

- The environmental permitting was simplified to support unconventional operations applying area-based regulation (ABR reduced the permits and authorizations from more than 60 to one per block).

- Definition of a new royalty framework to harmonize the royalty rate with the product type and the feasibility of optimal development in each unconventional area.

As a result, majors including Shell and Conoco are investing in unconventionals after their setback in oil sands, while independents such as Encana and Seven Generations are the leading producers in both basins.
Figure 3: Canada’s activity in unconventional developments

Canada production

Unconventional production

Investment – unconventional projects

Source: Rystad, Arthur D. Little Analysis.
3. Are other Latin American countries building momentum?

Mexico, Colombia, and Chile are the countries in the region that have expressed the strongest interest in developing their unconventional resource potential. However, they still need to build momentum to accelerate the development of their resources:

- The change of administration could lead to energy policy changes and different views from new authorities about the need to support unconventional developments
- Limitations in Pemex’s exploration budget, combined with a diverse portfolio of opportunities, make it difficult to secure financial resources to de-risk unconventional plays
- Growing demand for natural gas is supplied by imports from the United States at very competitive prices. The Mexican’s gas-prone shale will compete with the gas price set by Marcellus / Eagle Ford / Bakken shales and the gas prices at the Houston ship channel
- Although the development of unconventionals could help offset oil production declines in Mexico’s oil, the support of the authorities will be essential to build momentum and ensure the required investment conditions to attract both national and international players into this segment.

### Mexico

Mexico has been leading the exploration of unconventionals in Mexico, through the acquisition of technical information and the drilling of more than 20 unconventional wells in the last few years. In 2017, the authorities defined the environmental and operational regulation for unconventional operations and announced a bidding round for unconventional areas.

However, conditions for Round 3.3 were not defined until February 2018, including nine unconventional blocks in Burgos Basin. Many challenges remain to build momentum for unconventionals:

- Negative perception and fear of public opinion about the impact of fracking operations on seismic activity could have increased after the recent earthquakes in the country

### Colombia

Colombia pioneered the promotion of unconventional resources in Latin America and, in 2012, adopted a special regime to improve the economies of these types of resources. In early 2018 there were seven unconventional blocks contracted by ANH to Ecopetrol, Exxon, ConocoPhillips and other companies. However, the development plans suffered the double setback of the price downturn and intense domestic environmental controversy around the potential impact of fracking activity.

Ecopetrol has estimated potential in the Middle Magdalena Valley (MMV) basin of between 2.4 and 7.4 billion barrels of oil recoverable, and is waiting for the environmental permit approval to conduct a pilot project in an unconventional block. This pilot is targeting shale oil opportunities in the Luna formation in the mature MMV basin, where the availability of oil-related infrastructure and abundance of water resources provide attractive conditions.

### EIA Technically Recoverable shale resources

<table>
<thead>
<tr>
<th>Country</th>
<th>Trillion Cubic Feet</th>
<th>Billion Barrels</th>
</tr>
</thead>
<tbody>
<tr>
<td>Argentina</td>
<td>802</td>
<td>270</td>
</tr>
<tr>
<td>Mexico</td>
<td>545</td>
<td>13.1</td>
</tr>
<tr>
<td>Colombia</td>
<td>54.7</td>
<td>7.4</td>
</tr>
<tr>
<td>Chile</td>
<td>48.5</td>
<td>2.3</td>
</tr>
</tbody>
</table>

### Are other Latin American countries building momentum?

- Argentina
- Mexico
- Colombia
- Chile
To accelerate the pace of shale oil developments, Colombia still needs to overcome some serious challenges and prove that:

- There will be sufficient government support and commitment from authorities and regulators to promote the development of unconventional, even after the presidential elections of 2018
- Ecopetrol and other players can conduct pilots and initial evaluation studies to demonstrate the technical and economic feasibility of the opportunities, in spite of apparent community resistance to fracking
- Regulators can implement an efficient and agile environmental and social-permitting process
- Government can keep the peace deal and support agreements with militant communities to increase the Operation's security for oil and gas companies

Meanwhile, the oil reserves of Colombia have been declining, and concerns regarding the security of supply have grown. Commercial feasibility of large discoveries of natural gas in the Caribbean offshore has yet to be proved. Therefore, the country is in desperate need to incorporate new hydrocarbon reserves, and attention is increasingly shifting to the promising unconventional potential in the MMV basin.

Chile

Chile's national oil company, ENAP, announced in 2016 its intention to team up with ConocoPhillips to explore shale gas opportunities in the Magallanes region. The increasing gas demand in Chile has been one of the main motivations for the government and ENAP to consider shale exploration. Although ENAP announced the first horizontal drilling in a tight play in 2017, no wells have yet been drilled, and the first one is expected to be conducted in 2018.

Investments under the ENAP-ConocoPhillips agreement are expected to amount to USD 100 million across the first four years of the project. This partnership with one of the world's top shale producers might accelerate the learning curve during the exploration phase and help improve productivity by reducing drilling costs.

By the end of 2017 the Magallanes region is estimated to hold eight TCF of tight gas resources (source: USGS). However, drilling activity is likely to take off in this area if the concept is to be proved and the economic feasibility of forthcoming massive shale gas extraction in the basin validated. It is important to highlight that the price of shale gas in Chile will compete with the imported LNG prices, which could have a positive impact on the attractiveness for shale developments.
The development of unconventional hydrocarbons in different geographies will continue shaping the global oil and natural gas markets. Canada, Argentina and China are the countries with the highest unconventional productions after the United States. Other countries with high potential and interest in expanding their production, such as Mexico, Colombia, and Chile, still need to build momentum and align the technical factors with economic and regulatory incentives to ensure the inflow of capital investments to speed up the exploration/evaluation phases.

As the energy industry continues evolving, trends in supply and demand could change the incentives to develop the unconventional plays (growing share of renewables, peak of oil demand, etc.). Therefore, there is a closing window of opportunity for adopting a strategy to provide the required support to oil & gas players and take advantage of unconventional developments.

The downturn of prices, combined with the growing opportunities in United Stated basins, have reduced the interest of international companies in expanding their shale operations into new markets, but the coordinated efforts of NOCs and local authorities can help improve the attractiveness of Latin American unconventional plays. NOCs could play an essential role as pioneers willing to invest, reducing the risk of unconventional plays and leveraging their knowledge of geology, experience with local communities and privileged access to infrastructure in order to attract qualified international partners.

**Insight for oil companies**

- Latin American countries such as Mexico, Colombia and Chile have interesting potential in unconventional resources. Although there is still uncertainty regarding the feasibility of large developments, the growing demand for hydrocarbons presents an opportunity to supply the domestic markets.
- NOCs such Ecopetrol and Pemex have been acquiring technical information to better understand their unconventional opportunities. Their knowledge of local conditions can also help mitigate the surface risks for new entrants and potential partners.
- The price of acreage in the US has been growing, as the productivity of key basins keeps attracting investors. First movers in new shale basins outside the US will have the opportunity to acquire positions in high-potential areas at lower cost.
- Since in many countries public opinion is still very sensitive to the environmental impact of fracking operations, strong alignment of stakeholders and government support will be key to ensuring the proper conditions for massive unconventional developments.
- Oil price recovery and a supportive domestic gas price would facilitate de-risking greenfield plays in Latin America

**Authors**

Rodolfo Guzman, Paola Carvajal, Paola Perez and Roberto Imperatore
Local content after a booming oil & gas cycle

Ambitions and limits of local content development

Executive Summary

A cycle of booming oil and gas exploration and production activity ended in 2015. During the decade 2005–2015, pressure on local content intensified in most oil-rich countries. The time has come to examine the economic impact of both regulations and initiatives taken by private international and national oil companies to develop local economies.

Local content is a pervasive component of the oil and gas landscape. Local content regulations (LCRs) have escalated in the last 10 to 15 years among oil-rich developing economies to an extent that it has become a critical topic for the oil and gas sector. Yet, local content is neither new nor exclusive to developing economies.

Norway enforced the development of local suppliers in the early 1970s. With the Norwegian Petroleum Code, Norway insisted on localizing a large part of international operators’ R&D in the country early on. And recently, Scotland’s prime minister inaugurated Total UK’s new E&P facilities in Aberdeen, stating: “While we realize these are challenging times for the industry and workforce, this investment and expansion from Total is a signal that the company is committed to a long-term future in Scotland.” The commitment of oil and gas companies to the development of local economies is a global reality.

Since the mid-2000s, local content regulation – as opposed to contractual incentives – has become the preferred lever in most oil-rich countries, and the intensity of legal constraints has reached a higher level. The complexity and the bureaucracy generated by local content laws have led to mixed results.

This article aims at capturing what can be learned in terms of local content success from a decade of booming oil and gas activity. Which approaches have created value locally? What have been the main pitfalls to developing local workforces and suppliers?

1 See 4th licensing round, 1978–79, requirement of at least 50 percent of R&D necessary to develop a field had to take place in Norwegian institutions
1. Is regulation the right recipe to enforce local content

Some LCRs are extremely detailed. The Nigerian Content Development Bill (2003) reinforced targets of O&G activity localization with specific national content (NC) indicators. For example, the NC indicator for man hours in the FEED stage of a large capital project should reach 90 percent. For the tonnage, umbilicals should reach an NC indicator of 60 percent. In the Nigerian Local Content Act (2010), nationalization targets reach 90 percent for management positions, and 100 percent for junior and intermediate positions. In Brazil, regulation is so sophisticated that it requires a dedicated public administration unit to monitor its enforcement due to all the red tape involved.

Such stringent policies have delivered mixed results. In some cases, implementation has been successful and local content policies have allowed financing education programs and infrastructure, with local suppliers benefiting from national preference. However, in cases in which local content targets have been impossible to reach due to inadequate local business ecosystems or educational systems, such regulations have generated severe unintended consequences.

Angola, for example, went through a dramatic salary inflation in the mid-1990s when quotas for nationals were abruptly introduced without the local education system having been prepared (+4.145 percent in 1996, +220 percent in 1997). In Nigeria, local content raised inflation costs sharply. As an illustration, an analysis undertaken by an oilfield service company on the cost of subsea wells pointed out 60 percent inflation due to local content regulation. (See Figure 1.) Another illustration is the time to tendering, which has doubled on average in countries such as Angola and Nigeria because of lengthy local content procedures. Quota policies without adequate pre-existing networks of suppliers often lead to the syndrome of the middleman, in which local importers purchase goods and services from foreign suppliers and resell them locally at higher prices. In such situations, local content regulation becomes a hidden generator of inflation for the benefit of only a few importers.

Beyond the difficulty in aligning with quotas, companies also struggle to obtain and report local content data from their own suppliers. Indeed, under most regulations, operators are accountable for reporting accurate data based on information provided by their tier-one suppliers. Not to mention the variety of interpretation that the definition of “local company” can have. In some countries, a company is local if the equity owned by domestic stakeholders exceeds 51 percent of the capital (Kenya, Nigeria). In other countries, “local” companies are simply those incorporated in the country (Brazil). Often, the definition is missing or so vague that uncertainty prevails.

It is worthwhile to note that the most stringent and complex regulations have been passed in countries with limited economic ecosystems, by governments facing huge poverty challenges, among populations with little experience of large capital projects or understanding of the oil and gas value chain. When facing western oil giants, their first reaction is often defensive and politically driven by systematic mistrust in oil operators’ intent. What results is a lack of cooperation from day one in trying to reach balanced local content policies between stakeholders – government and international oil companies (IOCs) – that do not trust each other.

This initial bias against oil and gas companies is due to the historical reputation of O&G companies plundering natural resources without leaving anything positive and lasting behind, an image largely amplified and tarnished by populist local press. The defensive reaction of lawmakers is sometimes the result of ideological rhetoric against former colonial powers. Finally, the influence of the Norwegian “oil diplomacy” in a number of oil-rich developing economies is not neutral. A number of local content policies have been prepared by Norwegian advisors (most of whom are university professors or former public servants, not executives from Statoil) with a somewhat naïve belief that the same policy approaches which worked in Norway could also work in Sub Saharan Africa, where nothing is similar except the presence of oil.

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2 World Bank
3 OneSubsea: 58 percent inflation between 2003 and 2013. Increase due to more activities in the country (project management, engineering and fabrication of Xmas tree flow bases & Xmas tree frames, final assembly and testing of the completed Xmas tree); Fabrication costs ranged from four to 10 times the cost of the same fabrication constructed in Europe or the US
In contrast, some countries have developed more flexible regulations based on high-level targets and incentive mechanisms. Azerbaijan is a good illustration of this approach, with local content rules stipulated mostly in PSAs, as opposed to general laws. For example, for the Shah Deniz project, contractors had to provide mandatory training for nationals; however, training expenditures in excess of $200,000 in any year were recoverable. Other examples are the UK and Norway, where encouragement to support local industry was within a sensible margin (a 10 percent higher maximum on average than that of the foreign service provider), which made it possible to contain inflation.

Detailed heavy local content regulations do not bring expected outcomes without a proper ecosystem composed of minimum education infrastructure and local suppliers. Otherwise, such regulations will most likely feed inflation, weaken local manufacturing industries, exacerbate wealth gaps and social tensions, and worsen endemic corruption. This does not mean such regulations should not exist, as they often represent the only lever for governments to enforce requirements for oil and gas companies to contribute to development in the countries and communities where they operate. However, they should be conceived in a more open spirit than the politically driven objective of “making the IOCs pay for our soil.”

The reality is that oil and gas companies alone are not the essential pillar of local development. Through an analysis of successful initiatives, we will seek to capture the conditions for local content regulations to be impactful and not counterproductive.

Figure 1: Subsea well price comparison

*Figure 1: Subsea well price comparison*

<table>
<thead>
<tr>
<th>Year</th>
<th>Fabrication costs range</th>
<th>Increase due to more activities in the country: project management, engineering and fabrication of Christmas tree flow bases &amp; Christmas tree frames, final assembly and testing of the completed Christmas tree.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Price 2005</td>
<td>+74%</td>
<td>+58%</td>
</tr>
<tr>
<td>Price inflation due to local content</td>
<td>+74%</td>
<td></td>
</tr>
<tr>
<td>Other factors</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>Price 2015</td>
<td>+74%</td>
<td></td>
</tr>
</tbody>
</table>

Source: OneSubsea

Fabrication costs can range from 4 to 10 times the cost of the same fabrication constructed in Europe or the US.
2. The need for holistic approaches to ecosystem development

Leveraging direct, indirect and induced reservoirs of job creation

Oil and gas companies generate a small amount of jobs compared to their suppliers. An illustration of this situation is the Norwegian oil and gas labor force: in 2015, 28,000 people were employed by oil and gas companies, while more than 117,000 were in the oil-field services and manufacturing industries.\(^4\)

In the construction phases of large projects, EPCs and their suppliers generate more than 95 percent of the jobs required. In the production phase, O&G operators do not represent more than one-third of the jobs needed to run operations.

Given this reality, imposing recruitment quotas on IOCs is necessary, but will not create more than a few thousand local jobs at best. In addition to these unfavorable comparisons, the lead times to develop capable engineers in oil and are up to 10 years, far longer than for developing competent technicians and engineers in other sectors.

Beyond the capacity of operators and oilfield suppliers to create jobs locally, the overall sector is not as labor-intensive as others can be. Research reveals that when one job is created in the oil and gas industry (seismic studies, drilling, well services, etc.), two to four jobs are generated in indirect activities (mechanical engineering, freight services, cement manufacturing, electrical engineering, civil engineering, construction material, etc.) and six to eight jobs are created in the induced industries (medical, hotel, IT & communication, education, banking, insurance, etc.).\(^5\) In light of these ratios, which represent tremendous opportunities to establish lasting local activity, the objective of any local content policy or private initiative should be to ensure that these ratios have materialized in the local economy.

This is what Norway and the UK did in the 1970s by creating regional clusters (Stavanger, Aberdeen) and putting the emphasis on oilfield services and manufacturing. In two decades, Norway was able to create world-scale suppliers largely oriented towards exports (Aker, Seadrill, etc.). Even better, initial Norwegian local content regulation incentivized IOCs to place R&D centers in Norwegian clusters. A few years later, strong partnerships were established between Statoil and local suppliers, and suppliers started to develop technologies through private or semi-public collaboration. The degree of integration between state funding, universities, and Statoil and its suppliers within dedicated clusters has been an instrumental factor of success for the country.

Another example, which is more applicable to developing economies, is Trinidad and Tobago, where an industry of topside manufacturing was developed in the late 1990s. Thanks to an initial push from the government of Trinidad and Tobago, together with BP and other private investors, the topside of the Cannonball project was fabricated locally instead of being only assembled. The beauty of this industrial initiative was that after Cannonball, topsides for nine major offshore O&G capital projects were fabricated by the local company TOFCO for both local and export markets. In the Kingdom of Saudi Arabia, the petrochemical complex of Jubail followed the same approach.

From corporate social responsibility to supply procurement

O&G companies have changed their approaches to local content. Until recently, majors and independents considered regulations a burden to projects and operations, a hidden tax to be good citizens and have the right to operate. IOCs used to corner their local development initiatives into “corporate social responsibility” (CSR) departments, for intense public relations and production of impeccable brochures on the company’s commitment to creating a better world. Local content initiatives in such environments had limited impact and were at best superficial and at worst counterproductive, since they were placing communities under dependence of the company (social infrastructures, direct financial support).

These times are changing. Many IOCs are taking local content in a more professional way, and often integrate it within contract

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\(^5\) Analysis by Schlumberger on job creation in "stand-alone" oil and gas cities (Stavanger – Norway, Aberdeen – UK, Macaé – Brazil, Trinidad & Tobago) over the last decades, by industrial sector
& procurement or dedicated “local industrial strategy” entities earlier in the development phase. This approach also reflects a shift from financing social infrastructures or paying the communities in the premises of field operations, as they did for decades, to a more contractual approach whereby companies only pay for services delivered. In other terms, they incentivize lasting capabilities rather than paying for short-term social peace that inevitably deteriorates over time.

By doing so, companies also open the door to cost recovery of local content investments. Indeed, CSR activities are systematically excluded from recoverable expenses in most PSAs. If a larger project of local suppliers is being developed as part of the development phase of a capital project, cost recovery becomes possible and the scale of LC initiatives changes.

Addressing the local content regulation paradox

A paradox of LCRs is that they mostly target (and blame) O&G companies, while these companies cannot meet the high expectations of governments and local suppliers on their own for three reasons.

First, O&G companies are too large and rigid to make steps towards small and medium-sized local suppliers. Oil majors and large independents are full of cumbersome internal rules and global processes targeting systematic compliance with financial and legal criteria. Contracts issued by IOCs include terms and conditions accumulated over decades of projects, specifying drastic conditions that only international suppliers can meet and from which local suppliers are de facto excluded. For example, a typical request is that the value of a contract should not exceed 20 percent of the total asset value of a supplier. Or, proper financial accounts over the previous five years must be made available at all times by the supplier. In the same vein, large capital projects and operations require equipment with complex specifications that are difficult to produce in developing economies. For example, O&G operators only accept trucks with drastic safety protections, and well cement for drilling must have specific quality – it is the same for cranes and personal protective equipment (PPE). In many cases, especially when environment and people’s safety are at stake, O&G companies must respect international norms and cannot accept any trade-offs. However, in other cases, such as financial requirements, absence of flexibility is the result of internal policies and therefore could be more flexible.

Second, awareness of technical specifications and financial requirements is not shared early enough for local companies to invest and be ready for the early construction phase. A lot of materials and equipment could be produced locally with good preparation. Too many times local construction equipment suppliers have invested in equipment that was refused by O&G operators or their EPCs because specifications had not been known in advance. These cases led to bankruptcies, and generated scandals in local press and public frustrations. In the
end, IOCs incurred much higher costs than they would have invested in anticipated communication of future needs, planning, and technical and safety specifications of equipment.

With transparent planning of construction and operation phases shared well in advance, preparation for O&G projects and services could be anticipated and localized in the countries of operation. It looks so obvious and simple. Why don’t O&G companies systematically proceed in such an anticipated and open way? Because they seldom enter into business with small local suppliers. Large O&G companies talk to large suppliers.

The third reason is that the players most exposed to local suppliers in the development phase of large capital projects are engineering, procurement and construction contractors (EPCs) much more than IOCs. Large international EPCs rely as much as they can on local suppliers and services, in particular during construction phases. Liaising with small to medium-sized local companies is part of their savoir-faire. Every time they enter a new country, EPCs study in depth the local network of suppliers, and gain perfect knowledge of what can be leveraged locally at the best cost, what will need to be imported, and sometimes which activities could be groomed locally.

A strong limiting factor of success for local content development is late publicizing of large tenders. O&G operators wait for the final investment decision (FID) from the government to launch the construction phases of capital projects. They cannot commit to multi-billion-dollar investments without government approval. Once the FID is confirmed, O&G operators issue large tenders to international EPCs, which usually have around six to 12 months to answer before earth works start. In other words, the information related to goods, equipment, and services in terms of quantity and quality (specs) usually arrive too late for local suppliers to acquire the required capabilities. Local value-added activities are therefore made difficult for local suppliers to deliver on time. Before the FID, operators are uncertain and do not communicate; after the FID it is too late for local suppliers.

To address such a vicious cycle, the industry needs to rethink its approach to large projects and contract management. Long-term alliances between operators and EPCs could allow on-boarding of EPCs earlier in capital-projects preparation, way before the FID, in order to give enough time for preparing the development of local industries.

Local suppliers need to be supported before they can respond to tenders issued by IOCs. Such collaboration could happen in dedicated business centers that IOCs, EPCs, lawyers, accountants, academia, professional societies and energy and labor ministries could build together. In such centers of exchange, IOCs would share construction and operation planning months or even years in advance, explain the technical and HSE specifications imposed by the industry, describe contractual terms, etc.

Local content regulations could enforce the establishment of such business centers instead of imposing abrupt quotas on people or contracts, generating inflation and missing the great potential of indirect and induced job creation.

Finally, national oil companies (NOCs) are instrumental O&G players that can bypass this challenge of too-short, post-FID lead times of large tenders.
3. The prevailing role of national oil companies in fostering local content

All the examples of successful local content development results reveal the presence of a large national oil company (NOC). Brazil, Azerbaijan, Norway, Ghana, etc., each have a domestic champion. NOCs have been leveraged to develop local suppliers and train generations of local engineers that have benefited the rest of the industry. NOCs’ agendas are to cover both operational and national development objectives. NOCs can be the execution arm of local content regulation, and also guide lawmakers to issue pragmatic regulations.

NOCs are here to last; they have the luxury of time to grow the local economy. Together with their governments, they control the planning of exploration campaigns, drilling operations, new developments, maintenance programs, etc. They are deeply rooted in the economic ecosystem, whose growth is as important for them as production objectives. NOCs can do much more than IOCs can in playing with preferred conditions. IOCs have rigid global approaches to contracts, procurement and technical specifications, while NOCs can be more flexible.

For example, NOCs give an advantage to local companies through favorable conditions to help them compete on an even playing field. Illustrations of such favoritism can be ring-fencing certain product types or services from international competition, support borrowing from banks, guaranteeing volumes of orders to local manufacturers, re-scoping contracts to allow local producers to qualify, or staging the quality qualification criteria for local suppliers over time. This approach is required to allow local suppliers to have a chance to get contracts and grow, especially where limited industrial and financial capacities make local suppliers unqualifiable as per the international oil company criteria.

Figure 3: The prevailing role of national oil companies in local content development

<table>
<thead>
<tr>
<th>GOVERNMENT AGENDA</th>
<th>IOC AGENDA</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Maximize oil revenues in the long run through favorable contractual arrangements and controlled production overtime</td>
<td>1. Maximize operational margins and oil production during the time of the license</td>
</tr>
<tr>
<td>2. Develop domestic technical capabilities and supply chain through preferred conditions</td>
<td>2. Secure technical specifications and align with international or corporate procurement standards</td>
</tr>
<tr>
<td>3. Maximize local employment</td>
<td>3. Control salary level and hire highly skilled operational engineers and workers</td>
</tr>
<tr>
<td>4. Localize operations in the country all along value chain (refineries, petrochem)</td>
<td>4. Secure access to oil export and limit exposure to local market</td>
</tr>
<tr>
<td>5. Engage IOCs in long-term local content initiatives</td>
<td>5. Limit financial commitments in local content prior to FID</td>
</tr>
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NOC AS A CATALYST

1. Balance governmental requirements with the reality of operations
2. Provide preferred contractual conditions to local suppliers more easily than IOCs, and train suppliers over time
3. NOCs are the employers of choice and can take the time to develop engineers’ and technicians’ competencies
4. Can promote local players along the O&G value chain
5. NOCs can take commitment in terms of local content before capital projects start

Source: Arthur D. Little
Most NOCs have applied preferred conditions to local suppliers for many years, especially in countries where reasonable networks of suppliers exist aside from the O&G sector. This is the case for countries such as Saudi Arabia, the UAE, and Kuwait, and largely for South American countries. Have these preferred options borne fruits? Partially, as it is undeniable that large proportions of NOCs’ suppliers are local companies, but there is a flipside. First, these measures have generated dependency on preferential treatment and do not incite the pressure of efficiency that is present in competitive international markets. Ideally, these suppliers should be prepared to progressively move to export activities in order to avoid staying dependent upon a rent of preferential contractual terms. Second, after decades of nationalization, one could have expected that oil economies, such as the GCC countries, would run almost entirely through local suppliers. This is actually far from being the case. Though it is undeniable that NOCs do much more for local suppliers than IOCs do, NOCs tend to be restrained by the same syndrome pertaining to IOCs’ impact: rigidity due to their size and lack of efficiency in contract management. They are overwhelmed with bureaucratic, cumbersome procurement procedures, and consequently, their sense of urgency is not that of their local suppliers, whose cash flows deteriorate when contracts are awarded later than planned.

Just like IOCs, NOCs cannot develop local economies alone. A platform for collaborative and planned development of local ecosystems (or clusters) is mandatory. This includes education, labor and industry ministries, construction companies, lawyers, accountants, professional societies, and local and international EPCs. The concept of collaborative ecosystems illustrated by O&G business centers can have stronger impact when the country’s NOC leads them. More easily than IOCs, and for a larger number of projects, NOCs can share well in advance the contracts that will be awarded along capital projects and operations, detail technical specifications and HSE standards, contractual terms and conditions, etc. As opposed to IOCs, NOCs can plan and communicate forthcoming capital projects and operations well in advance in order to avoid peaks and drops in activity. They are not subject to the mechanism of the FID, which forbids IOCs from committing to contracts before the government has agreed on the overall investment. NOCs can share future planning before tenders’ issuance, and they can give EPCs more time to strengthen local supply chain.

What has become apparent when investigating successful local economies that benefited from the oil and gas sector is that the bedrock of success is not the regulation itself – this can only ever be a catalyst. The success factor is, rather, the intricate net of supportive industries and services and the collaborative approach across stakeholders that span from government entities, NOCs, IOCs, service companies and academia.
Conclusion: local content is here to stay

A common view in today’s “lower for longer” oil-price environment is that local content is a thing of the past, which is a luxury concept that has no place in the low-margin and low-tax-revenue settings we operate in today. In reality, local content continues to challenge operators and governments alike. Governments have to envision long-term views for their industrial development. In most cases, efforts are focused on how to maximize the oil rent from large O&G projects. Instead, the right question is where should the government invest oil revenues to develop other lasting and more job-intensive industries?

Furthermore, oil and gas companies, such as IOCs and NOCs, should share the planning of their projects and operations far enough in advance to allow local investors to prepare the ground. A shift in mind-set is required for IOCs, as oil giants have seldom shown capacity to introduce flexibility in their procurement policies. National oil companies represent the best lever to develop local industries, provided that they do not bear alone the burden of conceiving the industrial development vision that their government should articulate.

Arthur D. Little has developed unique capabilities in assessing the socio-economic impact of large industrial capital projects and operations in upstream and downstream oil and gas, in Sub-Saharan Africa and the Middle-East, South-America, and Europe. This approach has allowed large industrial players to prepare the ground for local content development initiatives, not only to respect regulations, but more importantly, to anchor and distribute project benefits in countries of operations in order to ensure long-lasting presence of IOCs and increased local capabilities at competitive costs for NOCs.

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www.adl.com/LocalContent
E&P cost reduction through systematic technology assessment and roadmapping

A case study in subsea technology identification, roadmapping and aggressive deployment

Cost reductions achieved by adopting new oilfield technologies are critical to improve the resilience of Exploration and Production margins, especially for subsea assets. However, new cost-effective technologies can only be deployed successfully with sustained and targeted R&D efforts. In this viewpoint, Arthur D. Little shows how new ways of engaging and working with technology suppliers to create technology roadmaps in one particular technology area – the subsea arena – helped to significantly reduce costs by phasing emerging technology deployment to allow technologies to mature and be deployed later along the roadmap.

**The oil-price environment**

The oil and gas industry has been subject to strong fluctuations in crude oil prices, with the price of Brent Crude dropping from $110/bbl in 2014 to $30/bbl in early 2016. Since then, prices have recovered, but this has highlighted the need for cost reduction to improve operational resilience. To deliver the many new development projects anticipated over the next five to 10 years in an economically viable manner, a new approach is required for the development and deployment of new technologies that can achieve sharp reductions in capital and operating costs.

**A drive toward cost reduction**

These cost pressures are especially felt in subsea production, an area characterized by higher initial investment and operating costs than any onshore counterpart. The trends within this segment are towards developments further from shore and away from existing production structures.

The greater investments required for these offshore developments has resulted in operators pursuing aggressive technical cost reduction strategies, which include:

1. **Use of existing structures** (e.g., an already-operational FPSO) with long tiebacks to the production area to eliminate the need for new topside facilities. This strategy may be limited by the availability of space on the existing platform, vessel and connecting lines.

2. **Increased use of subsea processing equipment**, e.g., using subsea boosters to pump oil/gas longer distances, and so facilitate longer tiebacks to existing structures or shore.

3. **Reduced diameter chemical and control umbilicals** by lowering the need for some of their functions or moving equipment subsea, closer to the well.

Umbilicals comprise a substantial cost element in any new off-shore asset development, and their budget impact increases as tiebacks become longer. In the case of a 50 km tieback, a conventional umbilical could account for 5 percent of the overall project cost (excluding drilling & completion).

As a result, oil companies are assessing ways of reducing dependency on umbilicals by moving more processes subsea, freeing space on the existing platforms and deploying smaller, cheaper equipment topside.

**Cutting the cord – Towards umbilical simplification**

Chemical and control umbilicals in offshore assets provide four main functions of oil & gas production systems:

1. **Electrical power**: to subsea equipment with varying power requirements (e.g., subsea control systems, pumps, compressors).

2. **Hydraulic power**: used to actuate subsea valves and provide barrier fluids required by subsea pump systems.
3. Communication: used to communicate production data such as temperature and flow rate – also for monitoring, control and safety processes.

4. Chemical injection: used to provide chemicals required for hydrate formation prevention, wax solidification prevention, oil fluidization, asphaltene flocculation prevention, corrosion control and scaling control.

Subsea umbilicals provide a range of disparate functions that cannot be completely eliminated or replaced. However, ADL analysis shows that there is substantial commercial benefit to be achieved from simplifying umbilical functions, as well as from partial removal.

Simplification can be achieved using a number of technologies which wholly or partially replace the umbilical function. In our structured approach to scanning the subsea technology landscape, we have identified a range of innovative enabling technologies under development, which could support the objective of umbilical cross-section reduction.

1. Power: subsea power distribution (SPD) systems to simplify power umbilicals and subsea power generation and/or subsea energy storage to remove the connection altogether.

2. Hydraulics: removing hydraulic-power and barrier-fluid needs from all-electric equipment, e.g., electric actuators and pumps that do not require barrier fluids (“topside-less”).

3. Communication: subsea wireless communication (SWC) as a means to rationalize expensive infield and tieback communication and power lines.

4. Chemical injection: flowline heating by active thermal management (ATM) reduces the need for flow assurance chemicals by heating production lines. Subsea chemical storage & injection (SCSI) systems can eliminate the need for chemical umbilicals by moving storage and boosting systems for all chemicals near to the well subsea.

The time needed for these technologies to be available for deployment depends on their technology readiness levels (TRLs), which represent how developed and reliable a technology is (in below illustration).

In our technology scouting, we identified a full list of potential solutions, engaging with each contractor to assess:

- The readiness level of each enabling technology and its ability to provide oil & gas operators’ typical requirements.
- The strategy adopted to work on its development (i.e., independent work, joint industry programs).
- A reasonable time frame to forecast availability for infield deployment.

The below illustration shows that the technology readiness level and number of solutions available varies significantly between the enabling technologies. SWC stands as the most advanced technology currently, with 12 identified solutions at TRL 7, and many solutions having multiple years of in-field use. Despite this, many operators are reluctant to use SWC because of issues such as reliability, latency, and bandwidth.

These technologies would need to be supported with the use of additional highly innovative systems. For example, edge-computing technologies are being developed to move analytical function subsea and reduce the demands on bandwidth and latency by using communication links to send “information” rather than raw data. Artificial Intelligence could also reduce the amount of data to be transferred and enable the implementation of subsea automated safety instrumented functions, therefore relaxing latency requirements. At the lower end of the TRL spectrum lie technologies such as SCSI. Implementing SCSI would reduce dependency on umbilical chemical lines, which typically make up a large proportion of an overall umbilical cross section and weight. However, this technology is only possible when supporting technologies are implemented, to reduce the volumes of chemical needs and flow rates. For example, supporting technologies such as active thermal management and digital optimization of chemical injection to reduce the required chemical volumes can make SCSI viable.
A subsea technology roadmap

Through our analysis of enabling technologies, we at Arthur D. Little propose a staged approach to reduce the dependence on existing technology (e.g., umbilicals) over time. This links with an organization’s ongoing R&D program and involves engagement with subsea technology vendors from a very early stage in order to understand current capabilities and the expected evolution of enabling technologies.

Our assessment is based on structured and validated interview and data analysis from 30 leading technology vendors. Our approach considers the expected time frame of ongoing R&D activities, the TRLs of required solutions, and interdependencies across solutions and key enablers. Based on this analysis, our summarized roadmap for deployment of these technologies identifies the steps needed to achieve a challenging cost reduction target. The illustration below provides an example of a stepwise approach to umbilical simplification which specifically builds value for investments that can support increasing levels of cost reduction by recognizing the benefits of future technologies.

1. **Active thermal management** of the flow lines, powered from the topsides, can bring significant cost improvements by reducing methanol and other flow assurance chemical volumes and flow rates (40 percent+ reduction in methanol volume). **Electric actuation** can remove hydraulic lines in the umbilical. These are currently used to actuate subsea equipment valves – either all at once or in multiple steps, in order to minimize risk (first on low-pressure hydraulic actuators, and then on high-pressure hydraulics devices).

2. **SPD** is a key technology that enables the deployment of high-voltage subsea solutions, with a limited number of topside connections: due to this technology, the number of lines in the main umbilical can be reduced and subsea boosting equipment may no longer require separate umbilicals. It is necessary to enable SCSI.

3. **SCSI** systems completely remove the need for chemical lines in the umbilical; if requirements for flow assurance chemicals are high and not mitigated in other ways (e.g., MEG injection), this has to be implemented alongside active thermal management of infield lines to further reduce chemical needs. SPD is also required to carry power subsea and distribute it at the required current and voltage, especially on long tiebacks.

4. **Wireless acoustic vertical link** from a central hub on the seabed to a buoy, and then wireless to topside equipment (e.g., via satellite), could further simplify the umbilical. Depending on the configuration of the seabed installation, connection from the Christmas trees to the central hub could be wired or wireless. O&G operators should study the application of wireless solutions to their specific cases, e.g., as backups/secondary links, to test their dependability.

After this stepwise implementation plan, the only connection left from the topsides would be the power lines; electrical power could be supplied via diesel generators on a small floating platform (which would include the vertical link) and carried subsea to completely remove the umbilicals.

The cost reduction potential

To determine the potential cost savings associated with the proposed technology roadmap, we demonstrated the cost reduction potential based on a typical use-case scenario comprising a ~50 km tieback to an existing FPSO.

Above illustration shows the estimated cost savings for each stage of the proposed technology roadmap (excluding drilling, completion and abandonment costs). The largest cost savings are found in the first phase of the roadmap: i.e., implementation of active thermal management and electric actuation. This provides capex savings of over 8 percent, resulting from significant reduction in the umbilical diameter. This initial option will be attractive for many operators due to the high technology readiness level of active thermal management solutions and the sustained interest from vendors in the development of electric actuation solutions.
Additional considerations needed to realize the benefits of aggressive technology deployment

In addition to the implementation of novel technologies in the pursuit of cost reduction, there are a number of additional considerations that operators should take into account:

1. **A shift in mind-set** is needed to effectively target cost reductions. Operators must be incentivized to move away from the conservative mentality of the previous decades. Solutions should be considered even if they do not have extensive records of accomplishments, and alternate vendor routes should be researched.

2. **Increasing joint efforts of industry players** (i.e., operators, subsea technology development organizations and smaller vendors): enhanced collaboration will be required to overcome the substantial challenges facing all players within the oil and gas industry.

3. **Embracing digital solutions** to optimize production functions, which are often over-engineered, would help to deliver further cost reduction. Examples include real-time monitoring and optimization of chemical injection, active thermal management and flow rate using distributed sensors. The effective localized application of AI solutions may also be of substantial benefit.

Conclusions

The low-oil-price environment has led many leading operators to seek out technical solutions to enable cost reductions in a range of assets. Arthur D. Little’s approach to these challenges is to carry out wide technology solution scanning, systemic analysis and aggressive technology deployment.

In the case of umbilicals, the large variability in the technology readiness of enabling technologies needed to replace or eliminate the need for the four main umbilical functions meant we could identify significant and increasing potential cost savings through a stepwise implementation approach which incorporates the benefits of future technologies.

However, additional considerations must also be taken into account, such as incentives to shift away from over-conservative and costly approaches, increasing joint efforts within the petroleum industry, and embracing new digital technologies such as distributed sensors and real-time optimization.

Authors

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www.adl.com/E&PTechRoadmap
In praise of perpetuity

National oil companies manifesto

Executive Summary

Perpetuity is every national oil company’s mission. Their articles of incorporation proclaim that they must toil for future generations. While international operators can wander from one country to the next according to the circumstances and various regulatory frameworks of producing countries, national oil companies cannot be so versatile. Neither can they pick and choose geologies; they remain attached to the hydrocarbon heritage exploited on behalf of their people. This praise of perpetuity is a tribute from ARTHUR D. LITTLE (ADL) to national oil companies, which strive to forge a path in a blurry world towards their historical destiny.

Gaze at the beige shades of dunes peppered by countless wells from your airplane window as you land at Hassi Messaoud airport in Algeria. Make out the drilling barges sprinkled across flooded forests as you fly over West Siberia in a relief helicopter. Follow pipelines and manifolds around the street corners of Kuwait’s residential neighborhoods. You will comprehend the petroleum industry’s promethean work of transformation, shaping on its way to its processing facilities, the land and maritime vistas of our humanity, as we enter a new Anthropocene.

States, multinational corporations and non-governmental organizations aggregate in financial, logistical and information networks that send men to extract hydrocarbons in the Arctic, the Gulf and the Appalachians. In this game of wars and alliances that blends politicians and industrialists, national oil companies stand out. They carry out, as either operators or regulators, the production of domestic hydrocarbons on behalf of their nations and for the sake of future generations. Many arose out of nationalization movements prior to the first oil shock of 1973. Today, they represent 75 percent of global production, and they control about 90 percent of global reserves. They sustain national industrial agendas and maintain, thanks to the diversity of their activities, the largest employment areas in their economies1.

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1 See Silvana TORDO with Brandon S. TRACY & Noora ARFAA, National Oil Companies & Value Creation, World Bank Working Paper NO. 218
1. Heroic figures of the oil & gas industry

After independence, national oil companies were the petroleum industry’s heroic figures. Back then, several industry leaders, some of which still guide their companies today, were young engineers put in charge of production assets overnight – assets that were, until that point, operated by foreign companies. Nationalization, a political decision which was, at times, sudden and without negotiation, made these technicians the men accountable for ensuring the prosperity of their countries. Today, portraits of them in hieratic poses adorn the boardrooms of Sonatrach, Pemex, KOC and ONGC. Their mission was colossal: increasing production levels, executing governmental instructions, recruiting and molding a new generation of technicians, paving roads, and erecting hospitals and airports. The intrusion of politics in the early days of national oil companies’ operations galvanized their leaders, but also exposed them to often-contradictory directions from governmental authorities. They faced an evolving equation of reconciling operating conditions with political instructions. Once nationalization movements were complete, the mandate of every national oil company’s CEO became –and remains today – to untie this double bind.

The celebrations of the 24th of February 1971 at Sonatrach, or the multiplication of shrines such as Burgan’s dream tree for KOC, constitute institutional monuments to the epic of national oil companies. Also enduring, in the interstices of their collective memory, is the experience of those teams who, moved by a nationalistic fervor, organized themselves to seize the oil business from the English, French and Americans. Service companies assisted with managing operations and facilitating the transfer of the knowledge necessary for sustaining production.

Nevertheless, national oil companies also had to turn to management consulting firms – which were emerging during the same period, but under different circumstances – in order to restructure their organizations, which they had inherited from foreign operators, and to take hold of their installations. The expansion of management consulting firms and the creation of national oil companies coincided, without there having necessarily been a correlation. Until the 2000s, ADL’s posters explaining the hydrocarbon industrial chain of Algeria had been hanging in the hallways of Sonatrach’s old headquarters. At KPC, black-and-white pictures of ARTHUR D. LITTLE consultants side by side with Kuwaiti engineers can be found, capturing the drawing of plans (in India ink, much before PowerPoint!) for a future holding federating the totality of the oil & gas sector in Kuwait. It was a time when consultants, wearing wide-collar shirts without ties and hanging cigarettes on their lips, helped Angola create Sonangol out of nationalized assets from Texaco, Fina, Shell and Mobil.
2. Once upon a time, Arthur D. Little chose to support national oil companies...

An ARTHUR D. LITTLE moment occurred in the history of national oil companies. It was contemporaneous with the decline of US production. Resource depletion in the United States, due to the aging reservoirs in Oklahoma, Florida and Texas, resulted in a power shift that favored national oil companies that were emancipating themselves within OPEC. In order to invert the dependency relationship with the West, the leading figures of the oil & gas nationalism chose to suddenly increase the price of an oil barrel. Ideologies clashed, but extraction technologies, budget-planning processes, IT and organizational know-how continued to be exchanged nevertheless...

The consultants who engaged in nationalizing the petroleum industry in Algiers, Luanda and Kuwait City were optimistic. They brought a managerial approach to their customers’ technical problems. ARTHUR D. LITTLE created a model for organization of national oil companies based on four objectives: (i) define a regulatory framework protecting sub-surface development and production; (ii) ensure industrial coherence of nationalized assets through complete control of the hydrocarbon chain, from the reservoir to distribution; (iii) increase production and life of reservoirs; and (iv) develop the competencies necessary for proper operations by establishing a national hydrocarbon school. ARTHUR D. LITTLE contributed to the creation of major national oil companies based on practical knowledge of sub-surface operating conditions and installations, according to a bespoke conception of management consulting – drawing the organizations in wood crayon, not prefilled templates or generic processes. Inspired by their clients’ cause, the consultants preferred a more Socratic approach conscious of the ideological stakes of the time, instead of transactional matrices structured in a conventional way.

Mega-mergers reconstituted the giants that had dominated the oil & gas industry at the beginning of the 20th century: Standard Oil is now Exxon; the Anglo-Persian Oil Company, BP; Royal Dutch Shell, evidently, Shell. The United States became an exporter again, thanks to its shale oil & gas production. Were we actually returning to a situation before 1973’s oil shock, when the E&P industry was American? The clear lines of ideological conflict had faded (the time of the great ideological battles is over!), and national oil companies became nostalgic, but unavoidable E&P actors, resisting the vagaries of international affairs and the emergence of alternative hydrocarbon sources beyond their control. They remain the largest producers and manage the largest reserves. However, their leaders seem to be searching for a reinvigorating domination model in a legalistic world – a world in which the West daydreams of phasing out hydrocarbons in a hesitant energy transition.
3. The evolving equation

The evolving equation between operational constraints and political instructions is at the heart of any national oil company’s agenda. It influences the decisions taken within the domains of action, such as investments, production, contract management and partnerships with international operators. Political and economic interests intertwine in delicate Gordian knots that must be untied by executive committees that lack the ideological clarity of previous generations. CEOs have been secularized; the managerial and technical analysis of operational and investment performance – e.g., OPEX & CAPEX efficiency – replaced martial declarations for national independence announced from the pulpits of oil companies. Faced with multiple simultaneous constraints, they were reduced to tacticians of the evolving equation. Apart from the priority given to the political management of production levels and renewal of reserves, the competition between countries to attract foreign investment forces their leaders to reformulate their visions in positive terms, originally established in the name of the higher national good.

The scale of some projects (heavy oil or natural gas transport infrastructure, for example) demands partnerships that are sometimes difficult to reconcile with a national agenda. Medium and long-term planning requires not only objectives in line with state budget targets and infrastructure projects envisaged for the country’s development, but also action plans, which are often in conflict with the maturity of the reservoirs, the operational requirements, the interests of foreign partners, company procedures and policies, or the contractual relationships with suppliers. The CEO’s role thus effectively became walking a tightrope between industrial needs and political obligations weaved by government authorities. CEOs used to take decisions on behalf of the authorities. Today, they manage risks – institutional, financial, industrial, etc. – by making the best of their circumstances, in a world of standards, conventions and contracts generally disseminated from the United States to the wider petroleum industry. Globalization and competition between regulatory frameworks, reservoirs, investments, etc., are a source of complexity, counterbalance and challenges to state monopolies.

The evolving equation is a manner of running a national company caught in conflicting forces between an unmovable state and erratic investors moving from one country to the next, based on regulatory attractiveness. “States have roots, and investors’ wings.” Some CEOs dedicate themselves to controlling their shareholders’ expectations, while others focus on conducting operations. Only a few occupy a tenuous and dangerous space – “a slippery path of ice,” as described by one of them – where strategy is turned into action, and vision into implementation.

In this context, in order to escape the inertia of internal constraints, the usual consulting firms generally propose a top-down, project management office process tasked with steering the implementation of transformation initiatives. But, all too often, these are plastic toys that dissolve in the stomachs of national oil companies facing field realities. Upstream is an industry for which men travel across magnificent and hostile landscapes, sleeveless workers drill holes several thousand meters deep, and engineers test installations, laying their hands on pumps vibrating under effluent pressure, like fruit farmers touching their trees to feel the coming crop. In oil & gas, outdoor action counts.

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4. Arthur D. Little’s counter model

ARTHUR D. LITTLE aspired to be different. For managers of the evolving equation, it recommended reclaiming the production asset infrastructure and industrial-practice skills of long-lasting national operators. Instead of a top-down, mechanical transformation process, ADL drilled knowledge wells into the many organization layers that irrigated the practice communities with rich, alluvial know-how, which had previously been buried in the memories of engineers and field operators.

As an example, a national oil company in the Middle East undertook a project of digging seven knowledge wells – to continue our metaphor – to restore the pioneering spirit of its early years, in the face of IOC3 partners that intended to impose their own policies and standards. These partners, particularly through their EPCs, wanted to convince the national oil company to standardize its processes and automate the majority of its installations in order to accelerate production. The IOCs were fixated on the short-term cycles of their operating licenses, which promoted standardization and automation, while the national oil company was focused on the long-term cycle of the full reservoir life. The IOC model is influenced by the industrialization (standardization, massification, economies of scale) of American clusters conceived for the production of non-conventional resources – shale oil & gas – whereas the national oil company followed an EOR4 way, customizing operating modes according to the particular maturity of each reservoir.

By the same token, the transfer of a mature field during an operating-license renewal is an ideal opportunity to directly observe the contrast in an IOC methodology versus an NOC philosophy. On behalf of its client, which sought to restore the legitimacy of its national mission and its technical credibility, ADL drilled those seven wells of knowledge. They were anchor points placed in different levels of the organization (CEO, operations manager, asset managers, etc.), and also at key points along the value chain (exploration, drilling, development, production and planning): (i) the memory and narrative identity of the national oil company; (ii) the future of production and reserves renewal; (iii) the maturity of reservoirs and facilities; (iv) the management of contracts with local suppliers; (v) the international cooperation and competition; (vi) the land use management; and (vii) the creation and development of a national petroleum school. The ultimate goal was to outline a vision for the future that would match the prestige of the national oil company’s history by awakening its memory and recording its industrial heritage (not only the resilience of its facilities after a century, but also its know-how, identity and legitimacy).

Another ARTHUR D. LITTLE project, with comparable dynamics but for a different national oil company, was the mapping of the architecture of a production system, from the reservoir’s geology to the production forecast. The objective was to remind the assets, scattered along a 3,000 km diagonal, that they belonged to the same production chain. A third interesting case was the establishment of a national petrochemical company from old distillation units and new steam-cracking plants. The approach was, counter-intuitively, to construct the new with the old, aggregating and harmonizing experience acquired from other plants, in order to accelerate the emergence of an operational memory that combined technical control with the use of automation.

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3 IOC: International Oil Company, NOC: National Oil Company
4 EOR: Enhanced Oil Recovery/Tertiary Recovery Stage
5. National oil companies are unique actors

ADLS consultants retained numerous observations from their missions at the foggy foothills of the Assam mountains, aboard platforms on the offshore fields of Qatar, on the gray plateaux of the Laghouat gas fields and among the moving dunes of Rub’ Al Khali. These notations are snapshots, sometimes even aphorisms, recorded during meetings or discussions, which testify to the traditions and practices of national oil companies. They reveal an intimate knowledge of the identity of these particular enterprises, which a superficial or mercenary gaze would not perceive.

- National oil companies are wardens of their reservoirs’ memories. Their role is to make things last – reservoirs and infrastructure. Maturity is one of their distinctive features.

- National oil companies are slow-footed, but they remain beholden to their reservoirs. This is in stark contrast to new, unconventional operators that favor speed, short-term and massification in their operations.

- National oil companies preserve the memory of their first wells. They conserve the pre-nationalization buildings: in Digboi in Assam, in Irara in Hassi Messaoud, in Ahmadi in Kuwait.

- National oil companies are institutions with a historical sense of protocol. Their leaders’ instructions are handwritten and stamp sealed.

- National oil companies manage frontier territories, they build roads through deserts and jungles, and their logos figure on the miles signs of the paths they open.

- National oil companies have social brownfields in their portfolios, which are operated to maintain employment in remote areas.

- National oil companies offer lifetime employment, but sometimes also short careers.

- National oil companies have a double agenda: to optimize production levels and to respond to the requests inherent to the activities of a state monopoly.

- National oil companies fuel the economies of their countries. They constitute two sources of income: one is the sale of their production on behalf of the state; the other, for their partner suppliers, is their spending, purchases, investments, and supporting the local industrial fabric.

- National oil companies appreciate consultants who, refraining from the transactional amnesia of the Chicago boys⁵, prefer to slip into the memory of their clients’ organizations to understand what they need to perpetuate as the changes they design are implemented.

The games of the traditional relationship between IOCs and NOCs, shaped as far back as the first oil shock, were replaced by an asymmetrical situation created by the American production of shale gas at first, and then of shale oil. US operators have drastically reduced their costs by industrializing their drilling and standardizing their operating practices. This crisis, linked to an abundance of oil available on the market, has led to the emergence of a new model for an oil industry already facing strong environmental pressures and global warming. Did the “shale revolution” and its industrial implications precipitate the roll-out of the energy transition?

Challenging the endurance of the oil industry obviously calls into question the perpetuity of national oil companies. Their industrial raison d’être has mutated while their mandate has remained the same, making it even harder to solve the evolving equation. Their government authorities have set changes in motion: opening up capital to private investors, introducing contractual creativity in partnerships with IOCs and service companies, subsidizing support activities, etc. But such projects cannot proceed without a thorough interrogation of their aspirations.

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⁵ So, shall we call those consultants, byproducts of globalization, who impose on their customers their rigid terms and conditions. Inspired by the Chicago school of economics – University of Chicago, most notably by Milton FRIEDMAN.
The ideology that favored the creation of national companies is long buried. Primary recovery nationalism\(^6\) – at its peak in the 1970s – disintegrated, benefiting an ideology of competition between reservoirs, technologies, men, etc. The evolution of operating conditions towards an increasingly complex secondary recovery has undoubtedly accelerated the decline of hydrocarbon nationalism. Faced with the end of that world, national oil companies hurry to solicit proselytizing consultants to define mechanical strategies. However, the creation of a federating vision, before any strategy, could forge an alloy of memory and future – a dialectic of memory keepers and dream catchers. A vision based on themes common to all state hydrocarbon monopolies: optimization of exploration and renewal of reserves, control of production levels according to the erratic needs of the market, development of a competitive processing industry (integrating refining and petrochemicals), and reformulation of the energy transition in national terms. National oil companies would also become producers of renewable energy, the development of which could be financed through controlled privatization of traditional activities. In other words, the privatization of fossil energy could finance the nationalization of renewable energies.

While such a vision is debatable, it could nonetheless help national oil companies write the story of their future by exploring the *raison d’être*, their memory and ambition. Before deciding, planning, or implementing any strategic action, the objective of this story-telling approach is to restore the choice about their future back to national oil companies – a choice they have lost during the transformations of recent years.

ARTHUR D. LITTLE, a centenarian consulting firm bearing the name of its founder, shares with national oil companies this sense of perpetuity across history. During those years of working on strategy, culture, organization, and performance of state monopolies in Mexico, Algeria, Kuwait and Indonesia, ADL acquired the conviction that national oil companies must embrace their singularity: an amalgam of patriotism, memory and knowledge. It is through the strength of this blend that national oil companies may constructively manage the evolving equation, in relationships with their government authorities. The lesson of this hydrocarbon nationalism, at its peak in the 1970s, remains auspicious today: the future of a national oil company hinges as much on reserves renewal investments as it does on creative decision-making against threats to the oil & gas industry’s sustainability.

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\(^6\) It was at the primary recovery stage that most nationalizations took place

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[www.adl.com/nationaloilmcompaniesmanifesto](http://www.adl.com/nationaloilmcompaniesmanifesto)
Dead end approaches for high-sulfur fuels

Refiners’ time window shrinks - they need to act

Executive Summary

Demand switch to low-sulfur fuels has been uneven across the globe, but environmental and engine regulations are pressing sulfur specs to extremely low limits. Refiners need to act accordingly since there will not be place to sink high-sulfur fuels anymore.

Demand for ultra-low-sulfur on-road fuels rose more than a decade ago in regions on the forefront. Late-comers are pushing towards this tendency and will catch up sooner or later; marine fuel is also playing its part on a global scale. Pressure is rising on refiners and their capacity to almost eliminate sulfur from their products.
1. Environmental drive from multiple angles

Energy-related emissions, and from oil combustion in particular, have been facing stricter and geographically broader limitations for the past decade, and the tendency keeps accelerating.

Pressure is not only coming from populations with greater environmental awareness, preaching for a world of clean energy and clean fuels, but also from environmental institutions and governments, which are following population demand.

This rise in environmental concern has supported many initiatives in the land mobility sector, such as:

- Fuel efficiency of on-road fleets: driven mainly, but not only, by engine and powertrain efficiency and vehicle bodywork design
- Installation of cleaner-fuel urban transportation systems and interurban corridors
- Growing penetration of electric vehicles (EVs) supported by subsidies: still incipient but threatening petroleum products demand almost exclusively in certain regions
- Changes in mobility behavior (car-sharing, car-pooling): mostly promoted in metropolitan areas, with the aim of alleviating on-site emissions and traffic congestion

In addition, other petroleum-fuel-demand segments have seen “dirty” products such as fuel oil, the largest destiny of refinery sulfur, displaced by natural gas, which reduces its market size and price. This fact also affects the share of petroleum products in the global energy matrix.

More than 98 MM BPD¹ (million barrels per day) of refined products are consumed in the world, and said consumption keeps growing at around 1 percent annually. Increasing share of natural gas and non-traditional renewable energy sources, plus the strong trend of increasing the use of electricity, have been moderating petroleum products’ demand growth and will continue to do so. This is such that, contrary to what we have believed for decades, peak oil will come from the demand side instead of from the supply side.

Although difficult to predict, both the potential displacement of up to 3 MM BPD of oil products globally by 2030 due to EVs and the availability of larger naphtha volumes of feedstock from the petroleum upstream will challenge refining capacity and product mix, deepening expected relative shortage of diesel.

This EV penetration will, however, be uneven across the globe and more aggressive in countries where bans on sales of fossil fuel cars have been announced. However, these announcements are meant to be effective from 2025 to 2040, and fossil fuel vehicle fleet replacement will take some years to be significant, and challenge mainly gasoline consumption.

Those 98 MM BPD of oil products will continue to have a market, but a large portion of them will need to be much “cleaner” than today to be tradable.

On-road vehicles: stricter limits for ~40 MM BPD

Regulation for reduced emissions is driving development of more demanding automotive engine technology and playing a preponderant role in the push for clean fuels. The impact is immediate for the countries or regions where the engines are produced locally (i.e., Euro V/VI). However, sooner than later, when late-comers discontinue production of less restrictive engines, they will need to adjust their fuel quality regardless of local regulation. Even though regulators are the ones redefining local specs on fuels, it ultimately is the adoption of new engine technology that requires low sulfur fuel to operate in working conditions.

For instance, for diesel-fueled vehicles, the chosen systems for gas exhaust treatment are EGR² and SCR³, the latter of which requires regular urea refills. The major difficulty for this treatment is the trade-off between NOx and particulate matter emissions. To help this equation, the fuel needs to be almost clear of sulfur, a state known as ultra-low sulfur. Otherwise, engine corrosion and catalyst fouling occur, and the soot (particulate matter) increases in volume.

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¹ According to the EIA (US Energy Information Administration)
² EGR: exhaust gas recirculation
³ SCR: selective catalytic reduction
In addition to this technical-based demand, there is also a commercial drive, which means changes in tendency according to what customers demand.

In order to fully eliminate or reduce sulfur from oil products, new refinery units need to be installed. However, these units emit significant greenhouse gases, so in the end, it is a trade-off between greenhouse gases at refineries (which, in some cases, are located close to cities) and contaminant gases and particles spread over the cities and roads.

Local regulations are distributed unevenly across the globe, and while some regions have been operating exclusively on ultra-low-sulfur fuels for more than a decade, lagging regions still offer markets for high-sulfur ones. These regions (mostly Asia, Africa, the Middle East and Latam) have been and still are playing the role of “sulfur sink.” However, the clock is ticking for them, as the era of high-sulfur fuel is running its course.

Marine fuel: ~4 MM BPD subject to IMO regulations

In October 2016 a global regulator, the International Marine Organization (IMO) committee, set January 1, 2020 as the starting date for the new MARPOL regulation. This regulation limits marine fuel sulfur levels to 0.5 percent (m/m – mass over mass) in marine fuels outside the already-much-stricter emission control areas (ECAs). Current marine fuel regulation demands a maximum of 0.1 percent sulfur content inside ECAs and 3.5 percent outside them.

Moreover, international marine trade is expected to continue growing at a 3–4 percent annual rate, as international trade usually surpasses GDP growth and about 90 percent of world trade is transported by ship.

Figure 1: Local sulfur specs for on-road diesel

- **Europe**: 380
- **US & Canada**: 290
- **Asia**: 210
- **China**: 170
- **Latam**: 130
- **M. East**: 70
- **Africa**: 40
- **Oceania**: 20

**Source:** Arthur D. Little

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4. **MARPOL**: Marine Pollution, the International Convention for the Prevention of Pollution from Ships
Fuel oil (the major destiny of refinery sulfur) finds about 40 percent of its market as a marine fuel (~3 MM BPD), which means this oil product will be severely restricted. However, even though its use for propulsion in the sea may be very limited, high-sulfur residues are withstanding and dodging reconfiguration in some places where there are still captive markets for industrial use and power generation with lighter specs than marine fuel. Nevertheless, both uses will get incremental participation of natural gas and renewable sources, motivated to some extent to meet with Paris Agreement commitments.

**Industrial use and power generation: ~ 12 MM BPD still dodging regulations**

The industrial and power generation sector, which is not as strictly regulated as mobility fuels, has been adjusting the sulfur content of what it burns unevenly across the globe. These have been the places of disposal for high-sulfur fuels. However, sooner or later, the SOx emission limits will reach larger, stationary engines, and even if some are located far from urban centers, the industrial and power sector will no longer be able to burn the amount of sulfur it burns today.

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5 Paris Agreement: signed in 2015, committed almost 200 countries to reducing greenhouse emissions so as to limit global average temperature to 2°C above pre-industrial levels
2. Refining segment under challenge

Any refinery product ends up with some content of sulfur because it is naturally present in crude oil. In the distillation of crude oil, sulfur components are dragged down to the largest (or, more accurately, higher-boiling-point) hydrocarbons. This is why the heavier the product is, the sourer it is, for any given processed crude oil.

In order to reach ultra-low-sulfur specs, even the lightest streams require some kind of treatment. Then each stream requires different treating severities depending not only on which refinery process unit it is coming from, but also on how sour the input crude oil is.

With the exception of some regions with recent light oil discoveries, especially unconventional oil, crude oil is not getting any lighter or sweeter for the majority of resource basins, which would imply greater challenges to reach specs.

Even taking into account the growing participation of shale oil and condensates, we estimate that 2035 oil production will be an average of 1.3 percent sulfur versus the current ~1.2 percent. In other words, the industry will have around 5 MM tons of sulfur to remove from oil products annually to reach today’s sulfur specs.

Regulation shows an uneven geographical pattern, and so does treating capacity in refineries to convert “dirty” fuels into clean ones. Regions with 100 percent clean fuels demand have developed enough capacity to treat full-range streams coming out of both distillation and conversion units. In contrast, late-comers show low desulfurization capacity and will eventually need to increase this; however, such developments carry no ease.

For instance, a world-average-size refinery (130 KBD) with medium conversion capacity – having average-quality crude oil as feedstock – placed in a market with ULS on-road fuels and IMO-compliant marine fuel will have to remove around 200 tons of sulfur per day to comply with product-quality requirements. The unit cost for removing would be around 2–2.5 USD/BBL (of refining capacity) in additional OPEX plus CAPEX.

Figure 3: Desulfurization capacity as a percentage of crude distillation capacity (KBD/KBD* 100 percent)
For non-deep-conversion refineries, the fuel oil market has been acting as a sulfur sink, as they have found demand in segments or regions for products with up to and over 3 percent sulfur content. This sulfur-heavy products market will shrink drastically by 2020, when IMO regulations take place.

Key prerequisites to pursue a profitable investment in a refinery are scale and conversion capacity. In a capital-intensive industry facing volatile (and thus sometimes tight) margins, scale is key to secure long-term sustainability, let alone to invest in treatment capacity.

Current scale and refining configuration across the globe is such that, in many cases, further investment will hardly be economically feasible.

Marine fuels will have to be desulfurized or blended with lower-sulfur fuels to enable them to meet the new specifications, but the incorporation of new shipping technology will play a role as well, especially exhaust gas scrubbers and built-in LNG systems.

Fuel oil has been centrally involved in marine propulsion since the early 20th century, and its application is now being challenged. Both demand for refined products and crude oil refining throughput will continue growing, and consequently, fuel oil production will too.

Since the majority of current marine fuel oil does not meet the 2020 standards, low-sulfur fuel oil and other distillates such as MDO\textsuperscript{6} will see its demand increased.

The current global sulfur average content in HSFO\textsuperscript{7} is above 2.5 percent, and with the new regulation, at least 80 percent of it will have to be removed, or some way will need to be found to dilute it with very-low-sulfur-content fuels.

Economics for residue desulfurization favors investment in large-scale refinery units instead of on-board vessel scrubbers, and we expect that this fact, combined with the additional demand for ultra-low-sulfur on-road fuels, will drive refiners’ investments: desulfurization or extra conversion capacity. The timing for adapting vessels for onboard scrubbing is shorter than that for a refinery, so refiners should react first. They cannot wait to see how much the shipping segment will facilitate the regulation compliance by itself.

We foresee a key role for refiners in adapting themselves and the shipping industry as fuel price-takers with relative reluctance to invest for compliance.

**Tight economics for desulfurization**

Desulfurization economics are tight due to CAPEX and margin impact:

- Since a market for sour products still exists, price spread between sour and clean products is relatively small. Also, to some extent low-utilization-rate refineries in some regions would be willing to purchase high-sulfur streams at discounted prices, hydrotreat them and sell ultra-low-sulfur-quality fuel, charging only the variable cost plus a low margin for the transaction.

- New treatment units need to be built, refineries’ hydrogen supplies usually fall short, and new production units are required, as well as extra investment, feedstock and energy to run them.

- A world-scale diesel hydrodesulfurization unit’s (i.e., 60 KBPD) expected CAPEX is around 4–8 MM USD/KBPD. However, a large number of refineries have small-scale streams, so they will require relatively small-scale and very expensive units (in terms of USD/BPD).

- Operating costs are significant, around 1–1.5 USD/BBL; desulfurization is utility-demanding and its hydrogen consumption is intensive.

- Costs are highly sensitive to units’ severity, natural gas – both for fuel and hydrogen production – local price and availability, plus other utilities’ availability (i.e., cooling water and chemicals).

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\textsuperscript{6} MDO: marine diesel oil
\textsuperscript{7} HSFO: high-sulfur fuel oil
OPEX plus CAPEX present value add up to 2–3 USD/BBL for each barrel of the treated stream.

Some factors favor economics of desulfurization investment decisions:

- Logistics sometimes levers the economic equation: In cases for which international trade is possible, an alternative to industrial reconfiguration may be to export sour products and import cleaner ones. Then the savings on logistics expenses provide a return on the investment. So the more isolated the refinery position is, the stronger the lever to payback investments. Said trading opportunities are real, but only temporal since high-sulfur markets keep shrinking every day and are increasingly distant.

- Conversion also helps the economy. Extra distillate volumes cracked and upgraded from heavier products leverage refinery crack spread, and, if conversion is hydro-based, cracked products end up being fully or at least partially desulfurized.

- In cases in which ultra-low-sulfur specs are a novelty, rushing the imminent industrial reconfiguration could bring commercial advantages over local competitors that have to import and blend – at least for a window of time until they catch up.

Estimating CAPEX depends on both regional and local factors, plus the existing configuration in the refinery. Heavy impact factors are:

- Existence of non-hydrotreated existing streams
- Existing treatment capacity and its severity; most of the time units can be revamped to meet specs at high capital-efficiency
- Hydrogen balance: hydrogen-deficit refineries will incur in new H2 plants with both significant CAPEX and OPEX. Naphtha-reforming units can partially supply the H2 circuit, but generally run short of supplying the whole hydrodesulfurization demand
- Ancillary plants: such as amine and sulfur plants, intimately related to regulation of on-site emissions

- Refinery scale
- Engineering and construction cost, highly dependent on local capacity and availability
- Location and infrastructure factors
- Capital cost (especially for high-country-risk-premium locations)

Whether to go for deeper conversion or just desulfurization is often a dilemma: operating hydrocrackers in high severity can secure ultra-low sulfur quality and an increased middle-distillate yield, which leverages the economics if supplying a distillate-deficit market. However CAPEX may be a deal-breaker when compared to current refinery value for these kinds of units.

Worldwide, transportation demands 40 MM BPD of gasoline and diesel, out of which around 25 MM BPD are not hydrotreated; to do so with world-scale units would require 100–110 Bn USD. Additionally, huge investments for ancillary units would be incurred.

Some projects only reach feasibility with the inclusion of deeper conversion or upgrading units (i.e., reforming, alkylation/polymerization or isomerization). Furthermore, desulfurizing naphtha streams come at an implicit cost besides the explicit OPEX and CAPEX; said cost is the RON (octane) loss due to olefin saturation in the hydrogenation process. This limits the blending into the high-grade gasoline unless there is a subsequent upgrading process.

In either case, these types of projects should be analyzed against an acid “do-nothing” case, in which a pseudo-catastrophic scenario is being presented; this implies that some kind of reaction from the refiners’ side is mandatory, and every month counts to maintain the competitive position. On top of that, company value (or at least its downstream business unit) will be wrecked if the enterprise is to stop refining and evolve into a trading company, giving away its refining margin value.

The real question, in most cases, is not of whether to invest, but of the optimal industrial reconfiguration (i.e., finding the proper balance between producing and trading) and the right pace and timing to execute optimal projects.
3. Finding the proper route and timing for compliance

Typical desulfurization challenges on main refinery streams

Some streams are typically difficult for refiners facing industrial desulfurization reconfiguration and forcing them to incur high-CAPEX sums:

- Straight-run naphtha: Highly dependent on crude sweetness, but usually requires some mild treatment and finally upgrading to be blended into the gasoline pool to reduce their impact.
- FCC naphtha: As a major sulfur contributor to gasoline pools, these streams have no other option than to be treated, with an exception in countries where second-grade quality accepts some sulfur content. Since the desulfurization process has the collateral effect of reducing the octane number of the treated stream, octane loss is a major issue for these streams and creates limitations for them as a premium gasoline blending component.
  - There is a global tendency to use selective hydrotreatment, minimizing RON loss in the light fraction (mostly mercaptans).
  - A heavy fraction may end up in the diesel pool if it has too much of a refractory nature (aromatics such as benzothiophenes).
- Coker naphtha: Typically high sulfur, silica and conjugated diolefin content streams. This means such streams have to be hydrotreated, but not before tackling diolefins (foul

Figure 5: Generic alternatives for compliance

Source: Arthur D. Little
treatment reactors) and silica (deactivates/damages catalysts).

- **Kerosene:** In aviation fuel blending, aromatic and naphthalene content are limited, but sulfur spec is rarely limited. Treating the kerosene topping stream will depend on the crude chemistry nature; hydrocracked streams are usually compliant enough to blend into the jet pool (with the necessary additives), although sometimes it is convenient to divert part of them into the diesel pool.

- **Topping gas oil:** Light fractions frequently present no major challenge, but have to be hydro-treated either way, and severity will depend on the processed crude nature.
  - Heavy fractions usually do not meet diesel distillation specs and need further conversion, or are degraded into the fuel oil pool.
  - The same happens to heavy cycle oil and heavy coker gas oil.

- **Light cycle oil/light coker gas oil:** Two must-be-treated streams; their dirty nature may result in not even being compliant enough for the soon-to-be-extinguished 2,500ppm diesel oil. Treatment is usually severe for these streams.

- **Residue:** With quite a negative refining spread, the challenge of stricter regulations, and the very high cost of hydrotreatment, its opportunity cost is decreasing and making refiners reassess their refinery conversion upgrade projects.

### Major considerations for re-configurations

No two refineries are alike, especially if considering their market, geographical positions and access to capital. Each reconfiguration should be carefully analyzed, taking into account its singularities and factors, such as:

- Market demand for every type and quality of fuel
- Local market-specific pricing and margin challenges and opportunities
- Technical restrictions
- Logistics limitations
- Country legislation and environmental restrictions
- Access to capital and its cost
- Company corporate strategy
4. Refiners’ versus shippers’ struggle

How to close the marine specs gap?

Even though the new regulation involves some major challenges, the solutions for these should be expected to come as a combination of the following approaches:

- Inland/refinery fuel blending to meet specifications
- Greater use of MDO/MGO
- Greater use of non-refined oil products
- Inland fuel oil desulfurization
- Ship onboard desulfurization

Thus, the dilemma is clear and, in the end, it will be a struggle between refiners and shippers, since each approach requires actions being taken by different players and all approaches imply investment and higher operational costs (or the use or sacrifice of high-value products) to comply with the upcoming specifications.

Refiners’ perspective

The marine fuel scenario will erode the current competitive position of those refineries processing sour crudes with low residue conversion and limited desulfurization capabilities. For them, it will be tougher to produce compliant marine fuel: residues are already facing negative spread versus crude, and it is unlikely that clean residue production will repay capital cost for hydrotreatment.

Nowadays, non-hydrotreated-residue producers struggle to allocate their output in nearby markets and will be forced to compete in a shrinking high-sulfur-fuel market, which means even further price penalization. As a result, blending higher quantities of distillates for fuel oil production appears to be a temporary alternative, but there will be reluctance to sacrifice middle distillates by diverting them to the fuel oil pool.

Vessel owners’ perspective

- Shippers should expect compliant marine fuel prices to rise, but increased prices will become common across the shipping industry.
- MDO and blended 0.5 percent sulfur fuel will be the easiest options to resort to. However, since their price premiums will be high, shippers will probably think about retrofitting vessels.

- Scrubber installations in both new and existing ships will be increasingly considered as an alternative to continue burning non-compliant, low-demand and cost-efficient high-sulfur fuels.

On the one hand, scrubbers are a relatively fast-adapting technology and may enjoy temporary advantages when compliant fuel prices suffer a major rise.

On the other hand, equipment is expensive (up to 4 MM USD CAPEX, depending on the vessel) and voluminous, taking up a portion of the cargo capacity, and requires regular discharge of residues at reception facilities. Installation feasibility will also depend on the type of vessel. Furthermore, with a proper scrubber and feed-quality combination, SOx emission can be maintained under permitted levels but may not be sufficient for NOx and PM emissions.

LNG-fueled vessels, together with LNG-ready ones (or retrofitted), are a viable approach to the challenge but would initially have fairly low penetration in the shipping industry.

LNG is a competitive fuel alternative and will reduce freight costs compared to low-sulfur fuels. However, LNG equipment is also expensive (around 5 MM USD CAPEX, depending on the vessel) and large, again taking up a portion of cargo capacity. Another hindering factor for LNG-fueled vessels deployment is the need for LNG terminal structures at ports which are yet to be extensively developed. That is why we only foresee feasibility on ships navigating well-defined and usual routes where LNG infrastructure can be warranted on end-to-end ports. This may be the case for routine container ships and some bulk cargo ones, yet it will be mild penetration.

It is worth mentioning that retrofitting vessels (scrubbers or LNG) is only technically and economically feasible in a small portion of vessels, since it depends on the existing vessel’s technology, design, scale, age, consumption, etc.; for the other significantly large part of the fleet, the only option is to run on clean fuels.

Methanol will have quite limited penetration. It faces similar challenges to those of LNG as it needs a retrofit and port infrastructure to be massively spread. It carries, however, the major safety upside of not having to be stored and handled at
high-pressure and cryogenic temperatures; another advantage is that it can be produced from renewable sources. Nevertheless, methanol price is usually higher than that of LNG and its energy density lower, which means more space is required for fuel storage.

Running on biodiesel is another option which will have short diffusion: even though it is produced from renewable sources and can adapt to diesel engines, its major setback is that the price is even considerably higher than that of ULSD, let alone compliant residuals.

Biomass is sometimes brought into question as an alternative to residual fuels. This fuel faces several major barriers: it has limited availability at all ports, price is not always competitive (if available), energy density is substantially lower than that of liquid/gas fuels (which implies larger volume for fuel storage), and biomass has significant emissions with regard to particulate matter (depending on its source).

Electric ships have been catching attention lately, and some projects are under way. Major drawbacks for this technology are the initial cost of batteries and engines, plus the operational limitations of the shorter range and charging time.

Outcome of the refiners’ versus shippers’ struggle

All above-mentioned solutions for ship owners are costly in terms of initial investment and face the short-scale challenge of investing in one ship at a time, with virtually zero effect worldwide. Solutions with no investment involved end up running on expensive fuels. Nonetheless, retrofitting a vessel is a faster process than reconfiguring refineries, and shippers are taking a spectator role to some extent, watching for outcomes before reacting.
Insights for executives

- Worldwide tendency to move to ultra-low-sulfur fuels – uneven among regions, especially time-wise
- Demand for clean on-road fuels coming from engines; fuel regulators mostly playing a messenger role
  - Engines’ technology does follow an environmental agenda
- Marine fuel regulations limiting marine fuels’ sulfur content to 0.5 percent outside the ECA in 2020 will set greater challenges to refiners rather than shippers
- Residual fuels may still find a non-marine-fuel market, but for a very limited time
- Price spreads between clean and dirty fuels are relatively low, and both CAPEX and OPEX are significant for fuel treatment, thus economics are tight
- Investment may be phased and part of it minimized with some trading activities in the short run
- Scale is key to leverage reconfiguration projects’ economics; many refineries will have serious competitive positions and survival challenge
- Environmental trend has already eroded present value of global refining business. Refinery value may be protected by identifying optimal actions and investments, but every month counts for survival – company value could be more eroded than expected
- Transformation formulas should be tailor-made since a combination of operational adjustment and new units may be the fittest solution. In some cases new conversion and upgrading units, rather than only hydrotreating, can bring the most profitable return on investment

How can Arthur D. Little support the key players?

- Feedstock supply, valuation and strategy
- Refining industrial, commercial, supply and trading strategy
- Desulfurization configuration design and feasibility
- Upgrading conceptual design and feasibility
- Long-term demand-supply trends for petroleum products

Authors
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www.adl.com/HighSulphurFuels
Innovation through contracting in the oil and gas sector

How contracts with external partners drive innovation in the oil and gas sector

Executive Summary

An increasing number of CEOs see innovation as a key lever for growth and critical to achieving sustained competitive advantage across the oil and gas sector. To be more innovative, firms increasingly complement their internal innovation capabilities with solutions, ideas, and technologies from external partners such as suppliers and service providers. It is critical to appraise the contract’s potential in order to foster innovation and understand the conditions under which this potential can be fully exploited, given the increased use of outsourcing and external partners in the oil and gas sector and their importance in driving innovation in outsourced service delivery.

Most recently, oil and gas companies have started using performance-based contracts (PBCs). PBCs underline the output, outcome and quality of the product/service rather than prescribing how it is delivered or which resources to use, and may tie at least a portion of the external partner’s payment to its accomplishment. An important element in PBCs is therefore the clear separation between the buyer’s expectations (i.e., performance goal) and the external partner’s implementation (i.e., how it is achieved). PBCs are typically characterized by a relatively low degree of contractual detail, as the focus is on the external partner’s outcome and a high degree of partner rewards are linked to its performance. Hence, the organization is dependent on the provider and has interest in choosing the “right” external partner.

In PBCs, the overall compensation to the external partner, consisting of the base price and an incentive, may be higher, because the risk has shifted to the partner and premium is explicit rather than absorbed into the owner's operating expenditures. The main benefit of a PBC is that it allows freedom for the external partner to deliver the product/service as it sees best. This results in more freedom for the external partner to engage in innovative activities as the partner is stimulated to lower its costs. In addition, this contract requires little information and knowledge on the inputs and processes required to deliver the product/service. However, it is extremely important to detail and measure the outcome/performance of the external partner. To successfully implement such collaborative contractual frameworks, oil and gas companies should emphasize three important stages of engaging with external partners when they want to stimulate innovation: the partner selection phase, the contract design phase, and the contract execution phase.
1. Importance of innovation is increasing, but few oil and gas companies focus on it

“Innovate or die” has become a well-known urge for large and small corporations regardless of the industry, as innovation in products and services – whether radical or incremental – is critical for companies’ sustained competitive advantage and long-term survival. For firms in the oil and gas sector this could not be more true; as the overall business structure changes, it is crucial to stay ahead of the curve through innovations. Innovation in the oil and gas sector plays a key role in reducing production costs, increasing production efficiency, supporting exploration, and ensuring that decommissioning activities are carried out effectively. Nevertheless, the oil and gas sector lags behind in developing innovative capabilities, commercializing inventions and benefiting from technological inventions from other industries. Figure 1 shows that the oil and gas sector is ranked only 12th (out of 13 industries) when it comes to being innovative.

<table>
<thead>
<tr>
<th>Industry</th>
<th>% of total</th>
<th>2014 volume¹</th>
<th>2013 volume¹</th>
<th>% change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Information technology</td>
<td>30%</td>
<td>380,325</td>
<td>367,028</td>
<td>4%</td>
</tr>
<tr>
<td>Telecommunications</td>
<td>13%</td>
<td>161,739</td>
<td>153,153</td>
<td>6%</td>
</tr>
<tr>
<td>Automotive</td>
<td>12%</td>
<td>153,872</td>
<td>152,221</td>
<td>1%</td>
</tr>
<tr>
<td>Pharmaceuticals</td>
<td>9%</td>
<td>111,479</td>
<td>99,950</td>
<td>12%</td>
</tr>
<tr>
<td>Semiconductors</td>
<td>9%</td>
<td>112,625</td>
<td>119,098</td>
<td>-5%</td>
</tr>
<tr>
<td>Medical devices</td>
<td>7%</td>
<td>92,462</td>
<td>99,290</td>
<td>-6%</td>
</tr>
<tr>
<td>Home appliances</td>
<td>6%</td>
<td>71,278</td>
<td>71,118</td>
<td>0%</td>
</tr>
<tr>
<td>Aerospace &amp; defense</td>
<td>5%</td>
<td>62,162</td>
<td>63,080</td>
<td>-1%</td>
</tr>
<tr>
<td>Biotechnology</td>
<td>3%</td>
<td>42,584</td>
<td>39,685</td>
<td>7%</td>
</tr>
<tr>
<td>Food, tobacco &amp; beverage</td>
<td>2%</td>
<td>26,333</td>
<td>21,758</td>
<td>21%</td>
</tr>
<tr>
<td>Oil &amp; gas</td>
<td>2%</td>
<td>24,158</td>
<td>23,925</td>
<td>1%</td>
</tr>
<tr>
<td>Cosmetics &amp; well-being</td>
<td>1%</td>
<td>11,017</td>
<td>10,197</td>
<td>8%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>100%</strong></td>
<td><strong>1,251,034</strong></td>
<td><strong>1,220,504</strong></td>
<td><strong>3%</strong></td>
</tr>
</tbody>
</table>

¹ Patents activity
Source: Thomson Reuters Derwent World Patent Index, Arthur D. Little

Firms can engage in innovation through internal innovation practices (e.g., internal development, R&D and corporate entrepreneurship). However, closed innovation activities, in which innovation is initiated based on the firm’s own resources and technologies, limit the firm in responding to changing environments. Internally, firms do not have all the necessary resources to succeed in complex environments and face difficulties when trying to capture the value of their resources. As a result, the full value potential often remains underexploited. Furthermore, internal innovation practices, such as R&D, may not fit the current needs of organizations as they are characterized by high costs and risks, slow time to market and inflexibility. To be more innovative, firms increasingly complement their internal innovation capabilities with solutions, ideas, and technologies from external partners such as suppliers and service providers (in the oil and gas sector this could be, e.g., maintenance providers of refineries or oilfield and drilling services providers). External partners enhance and drive innovation in products and services, as well as service outsourcing contexts in which providers innovate to improve and optimize the daily operations performed for the buyer. Innovation may occur with external partners as result of mutual learning, complementary resources and knowledge sharing. External relationships may, however, suffer from opportunistic behavior or coordination failures that may inhibit good performance and innovation activities. Inefficiencies working with external partners often lead to project delays. Bonuses or penalties for contracted work cannot mitigate delays or the entire project risk because they are proportional to and limited by the scope of the outsourced work. Oil and gas producers use contractual frameworks to manage intercompany relationships, improve efficiencies, and mitigate project delays. Traditional frameworks used by oil and gas companies are procuring material supply and oilfield services on a primarily transactional basis, with services performed or material procured at predetermined prices, rather than performance bases under which the service provider takes a greater share of both risk and reward.

Appraising the contract’s potential to foster innovation and understanding the conditions under which this potential can be fully exploited are critical, given the importance of outsourcing and external partners in the oil and gas sector and their importance in driving innovation in outsourced service delivery. This viewpoint aims to increase our understanding of the nature and form of contract types in the oil and gas sector which have the potential to improve performance and stimulate innovation.
2. Innovation improves effectiveness and achieves long-term economic goals

Innovation is the process of translating an idea or invention into a product or service which adds value and which the customer is willing to pay for. In the context of contracting with external partners, the innovation is initiated by the external partner. There are four common types of innovation, categorized based on the product’s/service’s new or existing market and technology:

**Figure 3: Types of innovation (contd.)**

<table>
<thead>
<tr>
<th>Innovation Type</th>
<th>Definition</th>
<th>General Example</th>
<th>Oil &amp; gas example</th>
</tr>
</thead>
</table>
| Radical/niche innovation | - Taking lessons, skills, and technology and applying them in a different market  
- Risk involved is low due to the reliance/reintroduction of proven technology  
- Requires changing the technology to ensure it is accepted by the new market | NASA’s aircraft cushions which form back to their original shape was later marketed for use in mattresses | Using nuclear magnetic resonance imaging – originally developed for medical applications – to map the amount of oil in rocks |
| Architectural innovation | - Creates new industries or replaces existing ones  
- Involves creating revolutionary technologies for new markets | Even though airplanes were not the first mode of transportation, they revolutionized the way people travelled | Development of unconventional fossil-fuel resources such as shale gas |
| Incremental innovation   | - Type of innovation which occurs most often  
- Utilizes existing technology and increases value to the customers in existing markets  
- Almost all companies engage in some form of incremental innovation | Minor changes to the design of a product or small updates to user experiences | Total’s partnership with Cybernetix to develop a new inspections, maintenance, repair system (SWIMMER) to solve the challenges of maintaining aging deep-water facilities |
| Disruptive innovation    | - Using new technologies or processes for the company’s existing market  
- The new technology – usually after a few iterations of improving ease of use and aesthetics – replaces old technologies and disrupts existing companies | Mobile phones over traditional phones. As mobile phones became cheaper, the sound quality improved and new functions were added. They replaced analogue phones | Use of new drilling techniques (e.g., hydraulic fracturing or fracking) for an existing market (i.e., upstream oil and gas companies) |

**Figure 2: Types of innovation**

Innovation in the oil and gas sector

Recently, the oil and gas sector has become increasingly characterized by lower prices for longer periods of time. This has forced many oil and gas companies to reduce their costs and thereby efficiently and effectively produce oil and gas in collaboration with their external partners (e.g., drilling providers, maintenance service providers, suppliers and others). Although lowering costs is crucial, by focusing only on this need, some firms may not be able to leverage the opportunities that come with a market upturn. E.g., firms that lay off skilled staff may encounter difficulties in replacing them in the future, and businesses that do not keep pace with technological advancements and innovations are unlikely to maintain long-term sustainable competitive advantage. For many companies to survive in the long term, this forces them to maximize efficiencies through harnessing new technologies and innovation. Innovation can either be an overnight game changer or deliver incremental improvements which enhance productivity and efficiency for oil and gas companies. Both are vital to a long-term sustainable profitability. Nevertheless, innovation is not cheap and not easy to achieve. It requires not only smart employees who engage in internal activities, but also...
support and execution from external partners such as service providers. In the oil and gas sector collaboration is especially important due to the high costs and long lead times associated with oil and gas advancements. Collaborative projects between oil and gas companies, oil field service operators and strategic partners, suppliers or universities are becoming the norm rather than the exception. In the oil and gas sector, innovation crosses the entire company. R&D is important around technology and business systems and processes for upstream companies, and around products and services for downstream companies. But it is also important to look for opportunities to grow in areas such as business models and the supply chain.
3. The effects of formal governance on innovation

Defining formal governance and contracts

Incomplete information and information asymmetry prevent firms from writing detailed contracts when outsourcing activities to govern their relationships with external partners. These information problems are seen as sources of costs that motivate organizations to vertically integrate and make the products and services themselves rather than buy them. However, to survive in a low oil and gas environment and sustain competitive advantage, oil and gas companies have started to engage in hybrid organizational forms (e.g., alliances, preferred supplier arrangements, outsourcing and joint ventures) that combine the advantages of outsourcing with the control and oversight of vertical integration. Thus, when vertical integration is not feasible or economical, and when buying from the market cannot meet demands for customization, coordination, and collaboration, oil and gas companies opt for engaging in hybrid organizational forms with external partners and service providers. In order to manage, govern and successfully execute these external partnerships, formal controls (i.e., contracts) are used. Contracts are legal institutional frameworks that specify the obligations of both parties, such as roles, responsibilities, performance expectations, payment terms, monitoring clauses, and dispute resolution procedures. As such, contracts reduce the uncertainty faced by firms and the risks stemming from opportunistic behavior of one or more contracting parties. In addition, contracts serve as a method for coordinating the collaboration by mitigating the risk that misunderstandings will disrupt the collaboration among the parties.

Types of contracts

There are three main and commonly used contract types in the oil and gas sector, including cost-plus contracts, fixed-price contracts and outcome-based contracts (performance-based contracts). Each contract type carries inherent risks and rewards for both parties (the oil and gas company and the external partner), and each contract type is focused on the input, processes, output, quality and/or outcome of the transaction.

Cost-plus contract refers to a contract in which the price to be paid to the external partner is based on the actual cost of production/delivery and any agreed-upon rate of profit or fee. The main benefit of a cost-plus contract is the ease of calculation. Although there are several calculation methods to determine the costs and pricing, the common thread includes the cost of the product/service and adds a profit amount. In addition, little information is required to use this contract type since the price changes dependent on the costs as the delivery of the product/service progresses. An oil and gas company that uses cost-plus contracts can justify price increases when costs rise. This method provides an easy and convenient way for businesses to...
set product pricing. Cost-plus pricing ensures that the provider is shielded from unexpected costs. However, cost-plus contracts largely ignore the role of buyers. If a buyer places a higher value on a product than the set price, the business loses out on profits. Accuracy is a critical component in cost-plus contracts. This contract relies on variable cost and sales estimates; if either of these estimates is inaccurate, then the cost structure is also inaccurate. This contract type also requires that business overhead is estimated accurately. Providers have little incentive to reduce or control costs because as costs rise, revenues/profits increase, resulting in the buyer paying a potentially inflated rate for a product/service.

**Fixed-price contract** refers to a contract in which both parties have agreed on a fixed price to be paid to the external partner for the product or service it delivers. In most cases, bargaining/negotiation on the price after the contract has been signed is not permitted. The price is held constant regardless of the cost of production. The biggest advantage of a fixed-price contract is that it allows the buyer to set an exact budget in advance. The buyer is aware of the total costs before the project starts. The fixed-price model typically limits the number of changes that occur during the delivery of the product/service. The seller is able to charge a high upfront cost under the fixed-price model. Once the price has been agreed upon, the buyer does not face uncertain surprises or need to contest the amount owed. As this contract type requires detailed knowledge of the costs and price of the delivery of the product/service, the contract is usually written in detail regarding pricing, costs, processes, roles and responsibilities, and inputs. However, fixed-price contracts are less flexible for managing changes or new requests. Any new requirements that arise during the execution may lead to price renegotiation and changes to the schedule. Excessive focus on maintaining a fixed price may come at the expense of quality, creativity and timeliness, and the value of the work often becomes less important than the price. A fixed-price contract may cost the buyer more than anticipated if the transaction is completed early or materials cost less than estimated. Both contract types, cost-plus and fixed-price, focus on detailing the inputs and processes required to deliver the product/service.

**Performance-based contracts (PBCs)** underline the output, outcome and quality of the product/service rather than prescribing how it is delivered or which resources to use, and may tie at least a portion of the external partner’s payment to its accomplishment. An important element in PBCs is the clear separation between the buyer’s expectations (i.e., performance goal) and the external partner’s implementation (i.e., how it is achieved). PBCs are typically characterized by a relatively low degree of contractual detail as the focus is on the external partner’s outcome and a high degree of partner rewards being linked to its performance. Hence, the organization is dependent on the provider and has interest in choosing the “right” external partner. In PBCs, the overall compensation to the external partner, consisting of the base price and an incentive, may be higher, because the risk has shifted to the

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**Figure 4: Summary of types of contracts**

<table>
<thead>
<tr>
<th>Contractual elements</th>
<th>Cost-plus contract</th>
<th>Fixed-price contract</th>
<th>Performance-based contract</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Contractual detail</strong></td>
<td>High</td>
<td>High</td>
<td>Low</td>
</tr>
<tr>
<td><strong>Payment schemes</strong></td>
<td>Costs plus a profit or fee markup</td>
<td>Pre-determined fixed price based on inputs and processes</td>
<td>Based on output, quality and outcome</td>
</tr>
<tr>
<td><strong>Advantage</strong></td>
<td>Easy to draw up the contract as little information is required to detail the contract</td>
<td>Buyers are shielded from unexpected costs</td>
<td>Goal alignment between both parties</td>
</tr>
<tr>
<td></td>
<td>Ease of calculating price/costs</td>
<td>Allows the buyer to set a budget in advance</td>
<td>Allows freedom to the external partner to deliver the product/service as it sees best</td>
</tr>
<tr>
<td></td>
<td>Providers are shielded from unexpected costs</td>
<td></td>
<td>Requires little information and knowledge on the inputs and processes needed</td>
</tr>
<tr>
<td><strong>Disadvantage</strong></td>
<td>Ignores buyer’s role</td>
<td>Limits the number of changes that occur during the delivery of the product/service</td>
<td>Buyer is highly dependent on the external partner’s knowledge and expertise</td>
</tr>
<tr>
<td></td>
<td>Need to accurately measure costs and sales estimates</td>
<td>Requires detailed knowledge of the costs and price of the delivery of the product or service</td>
<td>Requires detailed knowledge of the required outcomes</td>
</tr>
<tr>
<td></td>
<td>Providers have little incentive to reduce or control costs</td>
<td>Less flexible for managing changes or new requests</td>
<td>Requires the ability to accurately measure outcomes</td>
</tr>
<tr>
<td></td>
<td>Misaligned goals between both parties</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Risk</strong></td>
<td>Buyer bears most of the risk</td>
<td>External partner bears most of the risk</td>
<td>Risk is shared between both parties</td>
</tr>
<tr>
<td><strong>Goal alignment</strong></td>
<td>Misaligned – buyer wants to keep the costs as low as possible and the provider wants to increase them</td>
<td>Misaligned – provider wants to keep the costs as low as possible/buyer wants to receive the product/service within a certain timeframe and with good quality</td>
<td>Aligned – both parties want the same output, quality and outcome</td>
</tr>
</tbody>
</table>

Source: Various publications. Please refer to the reference list at the end of this viewpoint.
partner and premium is explicit rather than absorbed in the owner’s operating expenditures. The main benefit of a PBC is that it allows freedom for the external partner to deliver the product/service as it sees best. This results in more freedom for the external partner to engage in innovative activities as the partner is stimulated to lower its costs. In addition, this contract requires little information and knowledge on the inputs and processes required to deliver the product/service. However, it is extremely important to detail and measure the outcome/ performance of the external partner.

**Effects of performance-based contracts on innovation in the oil and gas sector**

PBCs are increasingly being used for the effective and cost-efficient sourcing/outsourcing of business services and integrated product-service offerings. A well-known and early example of a PBC is Rolls Royce’s “Power by the Hour” contracting type with the US government, in which Rolls Royce is compensated for the availability of the aircraft engines it maintains, rather than for the labor and spare-parts costs associated with the maintenance activities. In the oil and gas sector an example of a PBC is Diamond Offshore’s and GE’s performance-based subsea blowout preventer agreement, in which GE holds full accountability for performance. Diamond Offshore’s Pressure Control by the Hour™ model includes performance incentives to reduce downtime and improve system reliability for Diamond Offshore and its customers. Under the arrangement, GE Oil & Gas will provide “engageDrilling™ Services” for Blowout-preventer (BOP) systems on Diamond Offshore’s four sixth-generation drill ships, including management of maintenance, certification and reliability. The BOP systems included in the contractual agreement will be owned by GE. The performance is guaranteed through payments tied to the rig’s activities and BOP performance. This model shifts capital expenditure up front, with GE taking on more of the risks and burden. In this case, the external partner (GE) has the leeway to benefit through integration, optimization, and performance improvements, while defining the outcome in a way that directly aligns with the overall project. PBC contracts give oil and gas external partners the flexibility to manage execution details. This is contrary to the prevailing practice in the oil and gas industry in which control is retained by specifying execution requirements and material supplies in great detail. Performance-based contracts have two key characteristics which determine whether the external partner engages in innovative activities. First, the extent to which processes and behaviors are specified in the contract (i.e., contractual detail), as PBCs may contain detailed descriptions of outcome indicators and how they should be measured. Second, PBCs reward external partners based on the extent to which contracted performance is actually achieved.

**Effects of contractual detail on innovation**

When contracts are less detailed, and hence faced with less rules and obligations, the focus is more on the outcome than the process of achieving that outcome. As a result, partners have a certain degree of freedom to conduct their work in the way they think is best. A less detailed contract allows the external partner more freedom in decision-making regarding the delivery of the product/service. The external partner can, thus, choose which activities to engage in and which resources to use at its own discretion. As such, for contracts that are characterized by less detail, external partners have a higher degree of autonomy. To ensure that external partners engage in innovative activities, they should not be constrained by contractual rules and obligations. Thus, by granting external partners autonomy, the degree to which they can shape and influence their activities increases and they can quickly respond to changes. This autonomy therefore allows the partner the freedom and flexibility to initiate innovative activities.

All contracts are, to a certain extent, open. Within the range of open contracts, however, there is further variation: the precise degree to which a contract is open may vary across the range of open contracts. As such, contractual openness may be high, or even very high. A very high degree of contractual openness also paves the way for opportunistic behavior (e.g., to seek personal interests at the expense of the collaborative interest, as it results in too much autonomy for the external partner). When autonomy is very high, even the most reliable partners might be tempted to act opportunistically. Opportunistic behavior in the context of open contracts include, e.g., preparation of own competitive activities or selling the generated knowledge to a competitor. Hence, a very high degree of autonomy harms the overall quality and performance of innovative activities. Therefore, there is a certain inflection point at which adding further autonomy proves to be negative.

In sum, although a certain degree of autonomy of the contract is important to make the external partner engage in innovation, too much contractual openness creates a context that stimulates the external partner to act opportunistically by focusing on
its own individual objectives, thereby negatively affecting innovation.

**Effects of payment schemes on innovation**

When contracts are too open, the external partner has the opportunity to engage in opportunistic behavior. As noted above, curbing opportunism by detailing the contract is not considered to be a solution, as such measures will stifle innovation. To illustrate, by incorporating control and coordination mechanisms the contract will explicitly prescribe roles and obligations, determine the content of the transaction, and specify rules for violating contractual agreements. This obviously hinders innovation by setting the stage for a more rigid collaboration and relationship. Furthermore, extensive control and coordination mechanisms may hamper information exchange between the parties due to clear specifications of what is and is not allowed. Finally, increased control and coordination mechanisms can be considered a sign of mistrust, resulting indirectly in a barrier to knowledge transfer. Hence, balance between autonomy and appropriate control and coordination mechanisms is crucial for a successful partnership. An alternative approach to curbing opportunism, while at the same time allowing a certain degree of freedom in the contract, is to implement payment schemes by using compensation systems in which the external partner is paid based on the performance it delivers. In such cases, the rewards of the external partner are linked to its performance through incentive schemes that specify performance goals. In case rewards are only linked to specific behavior or the use of certain resources, partners tend to engage only in activities that are explicitly rewarded, and not in others (such as innovation). In the most extreme case, any new initiative would even be a breach of contract. On the other hand, in case rewards are clearly linked to overall performance, partners have more incentives to engage in unspecified activities that allow them to gain higher performance levels. In this case, innovative behavior is stimulated. Hence, when a partner is paid based on performance, it will exhibit activities in favor of reaching the contracted performance; it will find new and improved ways of delivering the performance to maximize its returns. As such, linking rewards to performance will direct the behavior of the partner towards collaborative goals even when it is faced with contractual openness and could behave opportunistically.
Conclusion

Collaboration with external partners is crucial to accelerating technology advancement, streamlining specifications and enhancing solutions that meet the challenges of the current oil and gas environment and position these companies to thrive in the future. Having a system in place to reward the external partner’s creativity for achieving performance and targets encourages innovation and creates an environment conducive to continuous improvement. When collaborating with external partners, oil and gas companies can use contractual governance to stimulate innovation. In order to achieve this, oil and gas companies should take into account to following:

How oil and gas companies can use contracts to stimulate innovation with external partners:

Oil and gas companies should emphasize three important stages of engaging with external partners when they want to stimulate innovation: the partner selection phase, the contract design phase, and the contract execution phase:

- **In the partner selection phase**, organizations should select partners with the right risk attitude towards engaging in innovation. Hence, there should be a sound partner evaluation and selection process incorporated prior to contracting the partner.

- **In the contract design phase**, both parties should not consider contracts only a safeguarding mechanism. Rather, they should realize that the way they structure the contract also has an effect on outcomes such as innovation. Depending on what type of innovation they want to achieve, they should carefully select a certain contract type and design the degree of contractual detail and the partner’s reward scheme.

- **In addition, during the contract design phase**, it also becomes important to involve not only legal specialists, because important knowledge regarding roles and responsibilities to include in the contract often resides outside of the legal department. Lawyers are less likely to be a crucial part of the relationships that develop at the operational level, and thus less likely to have the knowledge possessed by the employees who are involved in the day-to-day operation of the service delivery. Thus, both parties should also involve employees who will be involved in the day-to-day operations of the service delivery. Thus, both parties should also involve employees who will be involved in the day-to-day operations of the service delivery. As these employees are in the position to actually grant the autonomy to the external partner as stipulated in the contract, they should know how the contract is designed and live up to what is agreed upon during the contract execution phase.

- **Finally, when a less detailed contract is used with an external partner**, the soft elements of the relationship, such as trust, communication and commitment, become important during all stages. Both parties should make sure that there is a good relationship underlying the partnership at the strategic, tactical, and operational levels. It is also important that the formal and informal communication between the parties is set up well, not only to tighten the relationship and increase trust, but also to assure that both parties know each other’s business so mutual understanding and knowledge sharing can take place.
Arthur D. Little is uniquely positioned to support the oil and gas sector in:

- Developing and implementing innovation strategies
- Identifying and implementing innovation contracts
- Identifying possible partners and negotiating terms and conditions of contractual service agreements between parties
- Reorganizing the oil and gas sector and oil and gas companies
- Identifying growth plans for new companies or projects
- Identifying oil and gas business models

We have extensive project experience in linking strategy, innovation, and transformation in the oil and gas sector. Our internal experts combine extensive oil and gas experience with local insight and industry expertise.

Our extensive network of external experts ensures that each client will leverage the best-possible expertise, in line with the challenges and the context the company is facing.
We would like to express our gratitude to all companies with which we have interacted. They have been instrumental in the generation of content for this viewpoint. We would also like to thank the co-authors of the scientific papers from which many of the findings of this viewpoint have been derived:


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Many organizations that have undertaken safety improvement initiatives have found that while easy wins are typically accomplished early on, further progress often becomes increasingly difficult. Safety improvement typically depends on changing human behavior, which is driven by underlying emotion, habit and instinct, and not wholly rational or predictable. “Carrots and sticks” and other traditional methods therefore have limited impact on influencing behavior, and fail to truly engage employees and managers. Leading corporations and government policy-makers are demonstrating considerable success with alternative approaches, which overcome these barriers and achieve more significant and longer-term gains. Such approaches offer reinforcement to established levers for safety improvement.

The safety performance plateau

A common challenge facing organizations across many sectors is to sustain continued safety improvement in line with the expectations of regulators, business partners and shareholders. Executive-led initiatives can yield initial improvements before reaching a performance plateau, which can be hard to escape. Diminishing improvements can trigger loss of motivation and failure to engage middle management, which are critical to long-term success. More fundamentally, behavioral change required for improvement is notoriously difficult, and cited as the most common obstacle to progress. Human behavior tends to be driven by a combination of rational thought and emotion, habit or instinct, resulting in potentially irrational actions that are contrary to good safety practice. Therefore, traditional methods, such as those focusing on “carrots and sticks”, frequently fail. This is because they do not connect with people at these fundamental levels, which means true engagement will be limited.

The MINDSPACE model

In addition to safety, influencing human behavior is relevant to public policy, and the implications of behavioral theory for policy-making have been receiving increasing government attention in the UK. This has led to the publication of MINDSPACE\(^1\), a discussion document compiled by the UK Institute for Government, which reviews the latest developments in behavioral science and explores their potential impact on policy decisions. Much of the insight raised in this paper rings true to our experience working with client corporations as being highly relevant to safety management and culture.

Corporate policy-makers, including those responsible for safety policies, traditionally influence behavior by employing incentives and providing information about risks. A rational decision-maker can review accurate information and positive and negative incentives, and respond as the policy-maker intends. This is all fine in theory; however, real people are not perfectly rational, and their behavior is influenced by a range of factors.

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1 MINDSPACE: Influencing behaviour through public policy, IfG, March 2010
MINDSPACE represents nine of the most robust influencing factors on behavior:

- **Messenger** – who is communicating information
- **Incentives** – how our responses are not always rational
- **Norms** – what others do
- **Defaults** – “pre-set” options
- **Salience** – focus on novelty or relevance
- **Priming** – subconscious prompts
- **Affect** – emotional associations
- **Commitments** – public promises and reciprocity
- **Ego** – feeling better about ourselves

**Messenger**

How employees respond to a message is shaped by the identity of the messenger. This is clearly important when communicating safety policy or initiatives, as the wrong choice of messenger may render the message ineffective. People respond to different characteristics in a messenger, depending on context and desired impact:

- **Authority** – we have observed better results when senior leaders provide clear messages, and do so with authenticity.
- **Expertise** – healthy-living initiatives tend to have more impact when the messenger has biomedical credentials.
- **Peer effects** – if emotional commitment is desired, a messenger to whom the target audience can relate can be effective, e.g., a close relative of a worker who was killed in an accident championing safety improvement.

**Incentives**

Employees will often respond rationally to incentives, although impact can be limited, as *irrational* factors can dominate:

- **Loss aversion** – people are more responsive to potential loss than to equivalent gains. A company may wish to consider charging premiums for safety violations as an alternative to offering safety bonuses.
- **Probability** – people respond disproportionately to small probabilities, exaggerating the importance of an unlikely outcome, e.g., when participating in a lottery. This is also reflected in most people’s disproportionate aversion to high-consequence, low-probability events, which is widely recognized in research into risk.
- **Time** – people are generally more responsive to smaller, more immediate incentives than to larger, longer-term ones. This is frequently observed with healthy-living initiatives, such as healthy eating and quitting smoking, in which people’s actions are not consistent with the long-term benefits of a healthier lifestyle.

A practical example of loss aversion has been observed in the UK following the introduction of a statutory five-pence carrier-bag charge from most major retailers. Although many such retailers had been providing positive incentives for reusing and recycling carrier bags, typically through existing customer-reward schemes, providing a penalty in the form of an added cost for not reusing bags provoked a much stronger public reaction.

**Norms**

People tend to behave in ways that are *perceived* as normal. The ‘Most of Us Wear Seatbelts Campaign’ in Montana, US in 2002–2003 identified that actual seatbelt use was significantly higher than the public perceived it to be, and increased seatbelt use by communicating this fact in public media. We observed a similar improvement in compliance with the wearing of high-visibility jackets at the depots for a major transport operator that we supported in delivering a safety improvement program.

**Defaults**

If an employee is presented with multiple options, one of which is perceived as the default, they tend to be biased towards the default, even if it involves greater effort. The recent introduction of mandatory pension enrollment in the UK, with an “opt-out” option, is based on this principle, to encourage more saving.

**Salience**

People respond to what their attention is drawn to, often by the novelty, accessibility or simplicity of the information presented, while unconsciously filtering out other stimuli. This is often seen in optical illusions and other “mind tricks” in which the brain’s tendency to focus on details that are made to stand out can cause the observer to miss seemingly obvious details. When communicating safety information it is crucial to make sure the important messages are not the ones that the observer misses while focusing on something more salient.
Salience also explains why unusual or exceptional occurrences make a stronger impression, often leading to disproportionate reactions to risks that have been directly experienced.

**Priming**

Priming is when people are influenced by subconscious cues not logically related to their decision-making. Although this may be subliminal, people can also be primed by words, sights and smells. Priming is the least understood of the nine factors identified in the MINDSPACE model, but it does suggest that displaying safety messages and posters in the workplace can subconsciously, as well as consciously, prompt a response.

**Affect**

Affect is the act of experiencing emotion, and it can irrationally influence decision-making. For example, a positive mood can lead to excessive optimism, and vice versa. This can influence decisions relating to risk perception, e.g., the environment when waiting at a level crossing can influence mood, and thereby risk perception and the care taken when crossing. Effective safety messages engage an employee’s emotions.

**Commitments**

Studies have shown that people who commit to specific, achievable goals, especially publicly, are more likely to succeed. This is related to incentives and loss aversion, as breaking a commitment can lead to reputational loss. Commitment devices, such as informal written agreements, can have a tangible effect, as can reciprocity (“I’ll commit if you do”).

**Ego**

Most employees value their self-images and act to maintain them as both positive and consistent.

- Positive – people can be induced to act to create impressions of positive attributes, e.g., taking safety seriously.
- Consistency – people strive for internal consistency, and experience psychological stress when holding contradictory beliefs (“cognitive dissonance”). This can influence our perceptions, as we may deny facts outright to avoid contradiction. For example, “I take safety seriously” and “I can’t be bothered to wear personal protective equipment (PPE)” are contradictory, and may lead a worker to alter their risk perception to downplay the importance of PPE. Consistency can be used for a positive effect, e.g., by asking people to comply with a small request before making a larger, related request. This forces someone to reconcile having already agreed to one request with their unwillingness to do something else similar. It is sometimes used in sales, as the “foot-in-the-door” technique.

**Strengthening established safety improvement levers**

The traditional approach to regaining momentum in stalled improvement initiatives is to focus on engagement of staff. Behavioral science does not replace this, but instead provides further insight from which to strengthen approaches.

From our work with various clients, we have identified a number of keys to unlock further gains and escape the safety performance plateau. These steps can be enhanced by intelligent use of behavioral insight to remove barriers to desirable attitudes and actions.

**Use metrics that make continuous improvement realistic**

Focusing on high-level indicators of safety performance, such as accident rates, can contribute to stagnating improvement as lack of visible gains reduces motivation to push for further success. This creates a state in which failure to meet targets becomes accepted as a new norm. Shifting emphasis to alternative indicators of safety that might more realistically be improved can boost morale and break the norm. Salience is also important here – when communicating a variety of metrics, we want to ensure that managers and frontline staff pick up on the ones on which we want them to focus.

**Reinvigorate branded safety programs**

Launching a second phase of the program that kicked off improvements can create opportunities for further gains, often focused on a smaller set of more local challenges to foster engagement. Careful consideration of the messenger is required – should it be the same as in the original program, someone closer to the frontline, or an ambassador that has delivered success in a particular area? There may also be opportunities to exploit defaults when introducing new initiatives. For example, inviting all staff to take responsibility for a particular area of improvement, but presenting this as the “default” when choosing not to take up such a commitment, is seen as “opting out.” Rolling out suitable media to reinforce the program, such as posters, presents opportunities to use priming, and the tone of the program should be established with careful consideration of its emotional affect.

**Engagement of middle managers**

Lack of engagement at middle management level is a common reason we have observed for stalling safety initiatives. However, it can be remedied with appropriate training and development activity, the holding to account of management personnel, and
the effective sharing of the senior leadership’s vision. Appeal to ego and use of commitment devices can bolster efforts to get middle management on board with a safety program.

A key consideration we have identified when seeking sustained leadership commitment to safety improvement is the extent to which incentives are employed, as people should not be seen to be paid more to do their jobs safely. Sustained results require that the two are not separated, and reframing incentives in terms of penalties for poor performance may appeal to people’s greater sense of loss aversion.

Independent review

An independent review of corporate governance, performance or a specific safety program can provide deep insight that is hard to identify from within. This is especially true of behavioral factors, which may defy logic and be harder to spot if we, as leaders, already have “skin in the game” with previous and current initiatives. Independent review is distinct from audit, taking a broader view that is less focused on rote compliance and more open to identifying cultural, behavioral and organizational factors. We are engaged by a number of organizations, often on an annual basis, to report our independent review to the board.

Summing up

Many corporations face the challenge of the safety performance plateau. Behavioral change required for sustained improvement is notoriously difficult, and cited as the most common obstacle to progress. Behavior tends to be driven by a combination of rational thought and emotion, habit or instinct, resulting in potentially irrational actions that are contrary to good safety practice. Traditional methods, such as those focusing on “carrots and sticks”, therefore frequently fail because they do not connect with people at these fundamental levels. This means true engagement will be limited.

MINDSPACE offers additional perspectives to understanding the drivers of human behavior. Hence, when carefully targeted, it provides options for strengthening established levers for safety improvement.

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