world energy
We.
OCTOBER 2017

Number 36

BIG deals

World Energy no. 36/2017 - Targeted mailshot

C O N T E N T S

GIANNI
DI GIOVANNI

A heartfelt thank you

With this edition, my journey with *Oil* and *Abo* comes to an end. This is a goodbye after nine extraordinary years committed to creating a unique publication that has made its way into the international conscience of energy. We have sought to bring expert contributors with a high level of technical expertise who are also capable of writing accessibly about their complex fields. They were aided by a scrupulous editorial team that verified facts and sources but encouraged passionate, yet objective, reflection. The editorial staff has served an ambitious and enthusiastic mission, one that provides the debate on the future of global energy with an open editorial platform characterized by intellectual honesty and integrity. Our audience will know if we have succeeded in our intention to offer intelligible information on complex subjects while anticipating key trends and developments, from multiple perspectives.
If your assessment is positive, it is due to the fundamental contribution of the Eni Board, the members of the Editorial Committee, the editorial staff and Agenzia Italia, as well as the contributors who, over the years, have been featured on our pages, and to whom my most heartfelt professional and personal thanks must go. I leave the new director, Mario Sechi, a "used but good as new" machine, which with its more comprehensive title will now extend its gaze toward the new frontiers that the energy sector will conquer. I am certain that he will be able to steer "**we** – world energy" effectively toward ever more ambitious goals.

world energy **we**

Quarterly
Year 10 - N. 36 October 2017
Authorization from the Court of Rome No. 19/2008 dated 01/21/2008

Publisher **eni spa**
Chairman: Emma Marcegaglia
Chief executive officer: Claudio Descalzi
Board of Directors: Andrea Gemma, Pietro Angelo Guindani, Karina Litvack, Alessandro Lorenzi, Diva Moriani, Fabrizio Pagani, Domenico Livio Trombone
Piazzale Enrico Mattei, 1 - 00144 Roma
www.eni.com

Editor in chief
Mario Sechi

Editorial Director
Marco Bardazzi

Editorial committee
Geminello Alvi, Robert Armstrong, Paul Betts, Ian Bremmer, Roberto Di Giovan Paolo, Gianni Di Giovanni, Bassam Fattouh, Francesco Gattei, Gary Hart, Roberto Iadicicco, Alessandro Lanza, Lifan Li, Molly Moore, Moisés Naím, Daniel Nocera, Lapo Pistelli, Carlo Rossella, Giulio Sapelli, Lazlo Varro, Enzo Viscusi

Editorial team
Coordinator: Clara Sanna

Evita Comes, Simona Manna, Alessandra Mina, Serena Sabino, Giancarlo Strocchia, Manuela Iovacchini

Authors
Phillip Cornell, Antoine Halff, Paul Kralovic, Elenoire Laudieri Di Biase, Naki Mendoza, Andreas Raspotnik, Nicolò Sartori, Marco Siddi, Mark Smedley, Lello Stelletti, Davide Tabarelli

Thanks for collaborating in the creation of maps and charts: Anna Capalbo, Marika Novaglia, Simona Serafini, Pierluigi Spano, Francesca Vendrame – Eni

Editorial Staff
Piazzale E. Mattei, 1
00144 Roma
tel. +39 06 51996385
+39 06 59822894
+39 06 59824702
e-mail: info@abo.net

Social:
About Oil
@AboutOil
About Oil
aboutoil
Storify AboutOil
YouTube About Oil
@AboutOil
@about_oil

Authors' portraits
Stefano Frassetto

Photography
Archivio Eni, Contrasto (Reuters; Redux); Getty (Corbis); IPA (Alamy); Sie Masterfile

Design
Cynthia Sgarallino

Graphic consultant
Sabrina Mossetto

Graphics and layout
Imprinting www.imprintingweb.com

Printer
Stab. Tipolit. Ugo Quintily S.p.A. viale Enrico Ortolani, 149/151, 00125 Roma

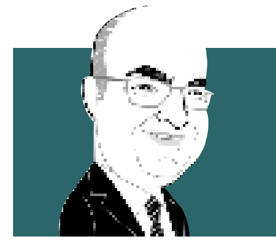
Translated by:
RR Donnelley

FIEG

Sent to press on October 9, 2017

MIX Paper from responsible sources FSC® C100565 www.fsc.org

Paper: Magno Natural 100 gr.



MARIO SECHI

A Story of Energy

Do you want to find out where the world is going? Look to see which way energy is going. Do you want to help your neighbor? Help him discover energy. Do you want to be successful? Put lots of energy into it. Do you want to get to the very end of everything? Go where your energy (and heart) take you. A five-year-old child looking at a compass said: "something behind things, something deeply hidden." Energy. That child was Albert Einstein, who established the mathematical formula of our "short century" (coined by the great historian, Eric Hobsbawm) and changed it forever with a mathematical leap into the future: $E=Mc^2$. Mass and speed, the ultimate outcome is the origin of everything: energy. The formal elegance of that Einstein equation struck me as a child, its simple force, its nuclear depth summed up in a glow of light, the beginning and the end, the Big Bang, a sensation manifestly represented by the only true artistic and literary stream that Italy has ever had: futurism, the movement of a mass that seems to have sprung from a painting by Umberto Boccioni. Energy. The world moves: speed, mass, energy. **we**—world energy—tells it as a sudden movement, a pause, a jump, a vibrant zigzag. This journey is a unique observation tower. We're talking about genius, work in the making, construction, projects, today and, especially, tomorrow. Until yesterday, this story was driven with style and wisdom by Gianni Di Giovanni (it is true, Gianni, it is a "used but good as new" vehicle, thank you). Now, it is my privilege to attempt to take a leap forwards under a new name: **we**. Us. A choral work of which the men and women of Eni are the beating heart. The future. We help it emerge with the metaphor of the signature and the handshake, an icon of every peace, the end of all wars, construction and common good. "Big Deals" is the title of this issue. For us, it is a new start that captures the long-term nature of the agreement, the contract, the mutual benefit, the growth and the essence of all human activity. Energy.

Energy as the primary source of transformation and evolution

In order to understand in which direction the world is going, you need to follow energy, its routes, its vast and powerful paths, such as those of the great rivers on whose banks civilizations are born and die. Large lungs are needed to travel long, far-away distances. The Mediterranean Sea is currently the liquid platform of impressive migrations that remind the advanced world of a commitment not to be missed: the future of Africa. Energy is the greatest transformation factor, an opportunity to build education, culture, state and well-being. As well as peace. It is the reality of nation-building, based on the creation and distribution of wealth. Energy. An interview with Tarek El-Molla in these pages captures the titanic proportions of the challenge, the catapult into tomorrow. Egypt's Minister of Petroleum and Energy outlines a picture that is not merely a plan of extraction and distribution, achieving energy autonomy, exploiting the Zohr and Noor mega gas fields, but a plan for product transformation and radical innovation. Egypt is preparing its industrial revolution. An ancient and magnificent civilization that emerged on the banks of the River Nile rediscovers its primary source: creating.

The principle of everything: supreme human activity

All this is possible thanks to the presence of men, women, technology, the combination of production factors, business. Defining energy as a "sector" is a semantic error. It is a reduction of its dimension to an "operation," instead of a grand design, a vision. Enèrgheia was a word coined by Aristotle to capture something that is present in space and produces effects. A combination of dynamis and enèrgheia. A sector? No. We are at the beginning of everything, philosophy, politics and supreme human activity. The dimensions in this planetary game of discovery, distribution and transformation of energy are fundamental. As Moisés Naím recalls in **we**, USD 3 trillion has been invested in the last 15 years in mergers and acquisitions, coming first in the ranking of global transactions. The reasons are manifold, not always dictated by certain calculations, by a secure advantage, but by factors such as the technological leap (Schlumberger which acquired Cameron for USD 16 billion, for example), the rationalization of the corporate and management chain (India and Russia putting order in their business scenarios), the attraction of new capital, the global trend towards fuels with a lower environmental impact, industry's imperative (businesses make things, while the technological evolution sets the standard) to reduce carbon dioxide emissions and the rapid transformation of "oil companies" into "gas companies," the energy source for transitioning to another world which we are still unable to →

plan with precision, but which we see in the long-term perspective, in the prospect of mega-trends in history of which renewable sources are a permanent element. It is a fascinating scenario that is played in advance, a construction forwards not to go backwards, a continuous reading of tomorrow.

On the roller coaster of trade, between adrenaline and disillusion

At the center of everything are the market: supply and demand, the cost and final price of energy and finance, trading, the physical and metaphysical dimension of Wall Street's daily sales and purchases. Davide Tabarelli gives us a fascinating tale of this come and go, starting with the milestone of the Sherman Antitrust Act and the decision of the U.S. Supreme Court in 1911 to uphold the breaking up Rockefeller's oil empire in order to ensure market competition. He recalls the historical phase of the $10 barrel in 1998, the skepticism (incorrect, as it later became known) of creative finance on the conservative oil world, and the climate where "those who worked in the oil industry felt ready to be fired, as if there was no need for them in the old companies," the catastrophic illusion of an immaterial world that could do without material, concrete, labor, drilling, pipelines or humans. A *Bonfire of the Vanities* (Tom Wolfe) confused in the astonishing and illusory *Bright Lights, Big City* (Jay McInerney), two essential books for understanding the climate of that era and its deviations, the rise and ruinous fall of strange creatures such as Enron, the thousand blue bubbles of Wall Street. A Leopardian massacre of illusions. Then, suddenly, again, an upsurge, rise, high profits and then down again, on the roller coaster of trade, the contained and

THE WORLD RUNS
"Energy is the greatest transformation factor, an opportunity to build education, culture, state and well-being."
In the picture, Umberto Boccioni, The City Rises, 1911 (Museum of Modern Art – New York).

rapid industrial transformation, necessarily short and accelerated, today's restructuring and mergers for tomorrow. Yet the bet is on the table: the barrel at $100 again. Is this possible? It seems unlikely, but, in reality, no one can know for sure, just as no one could have imagined in 2013 that, in three years, the price would drop to $50. Never play too much with fate. You have to respect it, watch it with caution, accelerate only when spaces open up for a new race.

Snapshot of a new world in search of new balances

In the upstream and downstream markets, there are correct and incorrect analyses, risky bets and predictable forecasts. It is a world where the dream is, every day, a reality. The panorama that emerges from the pages of **we** is that of a movement that is the product of an accelerated society (read *Social Acceleration* by Hartmut Rosa to get an idea of the world in which we live) in which "perception" and "instant" change the curvature of space. We run. But what is more important is knowing where to go. Between 2012 and 2017, the value of transactions in upstream oil & gas amounted to over USD 3 billion. In 2016, the value of deals doubled. The wonderful map of deals published in we says the scenario will undoubtedly change. How? Investments in Africa have resumed but are still far from the level of four years ago; Europe is beginning (again) a new Arctic era; the United States is a giant with a radical policy transformation (including that of energy) in progress; Russia and the Caspian Sea still represent land of the Great Geopolitical Game (read *The Great Game* by Peter Hopkirk); Canada, this giant of forests and lakes and infinite natural resources, is in limbo and its exceptional year was 2012, sixty months ago; Latin America is experiencing a season of political upheaval: giant Venezuela is burning democracy, while Brazil is seeking its permanent center of gravity which it has not yet found; Australia is looking for a gas route in a rich and fragile ecosystem. We are faced with increasingly complex challenges in an accelerated world where old paradigms are rusty. Great courage, culture and imagination are needed.

The Grand Slam of globalized energy

Our map is an open and closed space, a border, state, policy. The map is "the revenge of geography" (the title of a wonderful book by Robert D. Kaplan), it is the change of an era, a springboard to another scenario of which we have only seen the first glimpses. Roberto Di Giovan Paolo recalls this in an article that hangs on the nail of the Paris Climate Change (dis)agreements, COP21, the blurred photo of the end of the twentieth century with the election of Donald Trump and Emmanuel Macron (two party-less leaders), a Brexit that is not dictated by the economy but by a culture ("every Englishman is an island," said the poet Novalis) and an instant messenger barrage of uncertainty and continuous challenge. We live in interesting times. Maybe too interesting. Vladimir Putin and Xi Jinping, the presidents of Russia and China, during the latest summit of the BRICS countries in Xiamen, China, traced, in their dialogue, the outline of a new world order in which energy and technology are the driving force of transformation and artificial intelligence, as a tool "to dominate the world (verbal statement by Putin). All this is called contemporaneity, the spirit of time, Zeitgeist. This is the world in which we move. Energy is the number one Grand Slam game in globalization (there are two, an old and a new, as brilliantly explained by Richard Baldwin in *The Great Convergence*, a book published in 2016 by Harvard University Press), giving movement and strength to the winners, but not allowing (as we have seen) the existence of the losers to be forgotten. **we** tells of this new world, without forgetting the great (and small), good (and bad), useful (and useless) of the past. History is the teacher of life, while we are its distracted students looking to tomorrow. Energy is us. **we**.

@masechi

Exclusive/Interview with Tarek El-Molla, Egypt's Minister of Petroleum and Mineral Resources

A Fast-Approaching Future

Thanks to major gas discoveries in the Mediterranean and a vast infrastructure upgrade plan for its crude oil conversion system, Egypt has the opportunity to become a regional energy hub and reach its goal of energy self-sufficiency by 2018

Tarek El-Molla

Mr. El-Molla has been Minister of Petroleum and Mineral Resources of Egypt since September 19, 2015, when his predecessor, Sherif Ismail, was appointed Prime Minister. He worked previously for Chevron, where he was regional director for Central and South Africa, and for the Egyptian General Petroleum Corporation (EGPC), where he served as President.

GIANCARLO STROCCHIA

A journalist, he has contributed to newspapers like *La Voce* di Montanelli, *Euronews*, *Rai Format*. He worked at the Department of Public Information of the United Nations in New York and has practiced corporate and CSR communication.

Cordiality and firmness. In the eyes and words of Tarek El-Molla, Egypt's Minister of Petroleum and Mineral Resources, the country is using all of its willpower to take full advantage, now and in the coming years, of the opportunities offered by its domestic energy industry. Huge gas discoveries in the eastern part of the Mediterranean have led to broad ambitions for the entire sector, and those ambitions are manifest in specific, innovative projects. Moreover, the recent doubling of the Suez Canal has, for Cairo, been another launchpad to project the country towards a future of sought-after and necessary growth. El-Molla is fully aware of the potential offered by these developments and intends to focus his efforts toward taking full advantage of them.

Minister, what are the main energy challenges that your country is preparing to face over the next ten years?

My country has already started working on an energy industry change strategy, launched in 2013, which aims to close the gap between our energy production and local consumption and demand. This strategy is implemented through various actions to accelerate projects already under way. Secondly, our continuing goal is to increase the number of bid rounds so that over the year we enlarge our global exploration agenda and conclude a significant number of concession agreements →

Energy Dynamism

Each year, the Egyptian oil industry offers international tenders and agreements to increase oil & gas activities and national hydrocarbon production.

2016

Egyptian General Petroleum Corporation (EGPC)
Five licenses in five regions in the Gulf of Suez and the Western Desert, with a total investment of at least USD 154 million for the drilling of 30 wells.

Ganoub El Wadi Egyptian Holding Company
Bidding still in progress, results by the end of 2017.

2017

San Misr, a subsidiary of the Egyptian Ministry of Petroleum, has renewed its agreement with the Iraqi state-owned company **South Oil** and the **Zubair Corporation**, which manages the Zubair oil field in the province of Basra, Iraq. The agreement covers maintenance work on the mechanical and electrical structures of the new production facilities in the Zubair oil field, work managed by Eni and other companies.

Egyptian General Petroleum Corporation (EGPC) and Iraqi company **Somo** have signed an agreement to import a million barrels of oil per month from Egypt. The agreement is a prelude to a more extensive future collaboration between the energy industries of the two countries, a collaboration sanctioned by a protocol signed by the two governments.

An agreement between the company **Southern Valley Egyptian Petroleum Holding (GANOPE)** and the companies **Schlumberger** and **TGS** for the execution of two geophysical survey projects in the Egyptian Exclusive Economic Zone (EEZ) in the Red Sea and in the south of Egypt, with investments amounting to more than USD 750 million. The plan follows agreements for reviewing sea borders in the Red Sea between Egypt and Saudi Arabia.

and contracts. At the same time, we want to adopt a plan to improve our refinery system by expanding and modernizing certain plants. Because this is a project that is already in progress, we will soon be in a position to face the challenges that may arise in the future, problems related to exchange rates, price fluctuations and the increase in consumption and demand. Therefore, in 2014 we began a period of transition that will continue for another five years, combining adequate local production, the structural upgrading of the refining system and governmental reform. This period will see subsidies rationalized and improvements in the product value chain. This in turn will lead to greater efficiency, and therefore, allow us to be ready to address the ambitious plan we have undertaken.

What bearing does the energy industry have on future projects related to your country's economic relaunch?

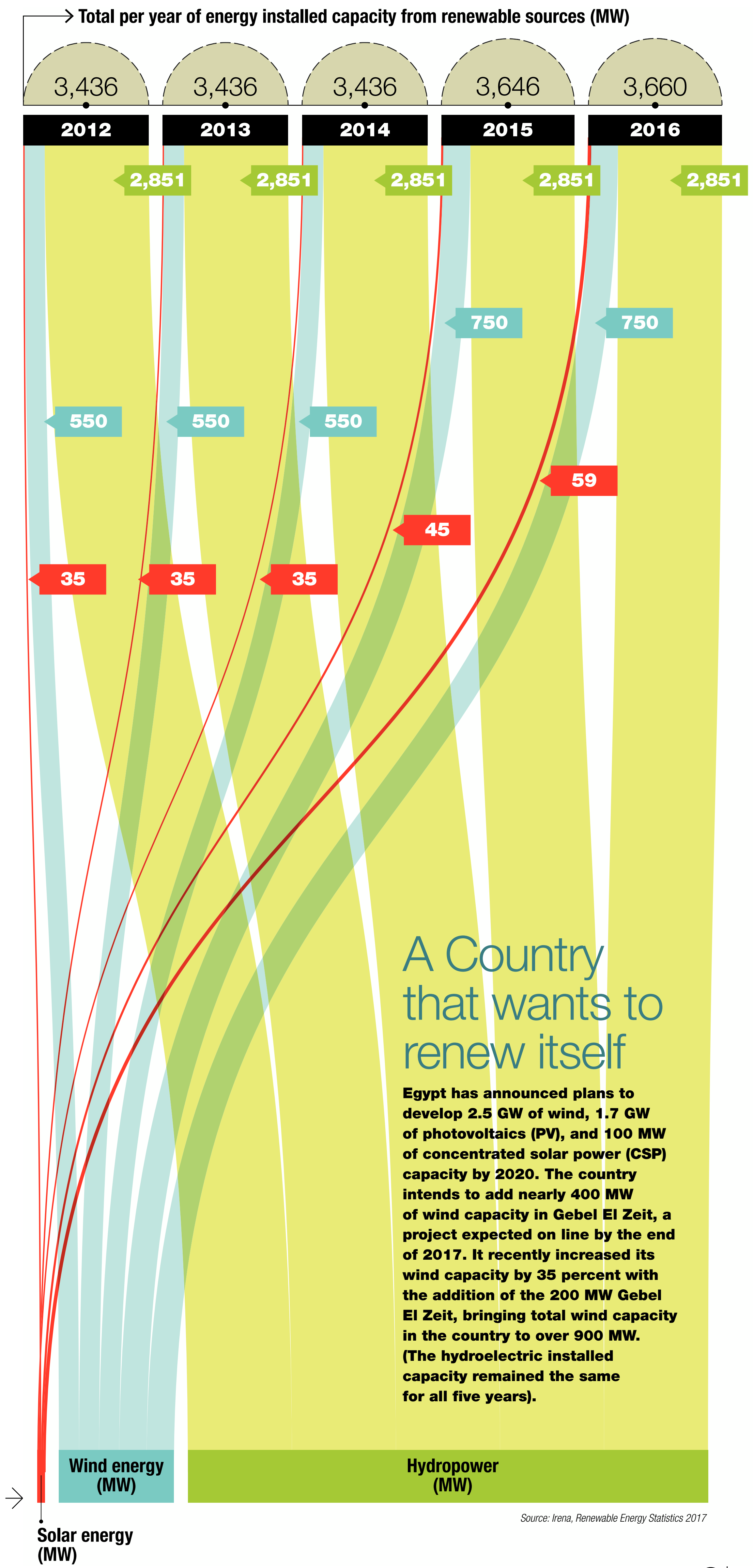
The energy industry is certainly a key element, capable of contributing to the realization of important projects for our economy. This is equally true for any developing nation, as energy is an engine for growth for all such countries and economies in the world. We are seeking development through our gas discoveries and the acceleration of projects related to this resource. We are working hard to close the gap between consumption and production, a gap that currently forces us to import LNG. We will reach self-sufficiency by the end of 2018, an accomplishment that will enable us to supply energy for all of the country's strategic sectors. We have already managed to meet industry demands, and in the future, we will meet all domestic and commercial needs. At the same time, if there is a surplus of production, we will consider two strategies in parallel. On the one hand, we will prioritize our commitments to exports and the contractual obligations that need to be fulfilled. On the other hand, we will try to use any extra gas for added-value industrialization and transformation specifically in the petrochemical industry. We will also expand and modernize our refinery system, which will enable us to achieve some products in line with the most advanced standards, up to Euro 5, so that we can export them. The position we would like to reach is that of a regional energy hub, not only for gas, but also for crude oil and petroleum products. Egypt benefits from a privileged geographic location between the Mediterranean and the Red Sea. We have oil pipelines, thanks to which we already receive the crude oil that is coming from the Gulf Countries, and also the important contributions of the Suez Canal. With these assets, we can achieve the total interaction that a hub has to offer, whether for trading, storing or consumption. The same situation applies to the electricity industry. We will be regionally connected to North Africa, the Middle East and to neighboring Arab countries. We also plan to connect with Europe by an undersea cable through Cyprus. All of the above are important elements for achieving the role we aspire to play.

The recent major discoveries of Gulf fields off the coast of Egypt suggest a great development of this resource in the coming years, making it possible for Egypt to return to being a net gas exporter. Is this what you hope for?

As regards the latest gas discoveries and the way in which we want to go back to being net gas exporters, the answer to this would have to be yes and no. No doubt in the future we will be in a position to achieve energy self-sufficiency—thanks to the work carried out with our strategic partners, such as Eni and BP, we have been able to discover the supergiant gas fields of Zohr and Nooros. With the implementation of the first phase of the project for entering these gas fields into production in 2017/2018, total domestic gas production is expected to exceed 5.5 billion cubic feet a day. Therefore, we will achieve self-sufficiency and we will become an export country; however, this is not what we hope for. What we want to develop through the gas surplus are value-added industries such as the petrochemical products and transformation sectors. Therefore, essentially, we are working in parallel with the development of our industrialization and modernization strategy for the petrochemical sector.

The revolutionary discovery of the Zohr gas field appeared to open a new chapter for your country's, and indeed the entire Mediterranean basin's, energy development. Are we in fact witnessing a new energy era for the entire region?

Within the Mediterranean, Egypt benefits from an excellent geographic position. We have the Suez Canal, and also other important infrastructure, such as the LNG plants in Damietta and Port Said, the refineries on the coasts, the Sumed oil pipeline that travels from the Gulf of Suez to offshore Alexandria, a national gas network and, of course, our natural resources. We are also expanding our refineries and increasing their capacity. The combination of these factors, in addition to the partnership launched with the Eastern Mediterranean countries, will lead to the development of a regional hub for gas production and export. In fact, we are working on developing a legislative framework to move in this direction, both as regards the gas market regulator and in terms



Source: Irena, Renewable Energy Statistics 2017

A Country that wants to renew itself

Egypt has announced plans to develop 2.5 GW of wind, 1.7 GW of photovoltaics (PV), and 100 MW of concentrated solar power (CSP) capacity by 2020. The country intends to add nearly 400 MW of wind capacity in Gebel El Zeit, a project expected on line by the end of 2017. It recently increased its wind capacity by 35 percent with the addition of the 200 MW Gebel El Zeit, bringing total wind capacity in the country to over 900 MW. (The hydroelectric installed capacity remained the same for all five years).

The Giant

The adventure of the large Zohr gas field, located offshore Egypt in the Eastern Mediterranean, began in 2012, when 15 research areas were tendered. Monitoring reveals that block 9 hides a rock-tank and August 2015 marked the sensational discovery that sanctioned the effectiveness of Eni's "dual exploration model," subject to the spin-off between Eni, CNPC and Exxon Mobil. In 2016, Zohr was the key player in a process that resulted in the issuance of minor shares in the Shorouk license with BP and with Rosneft: 30% was sold to the Russian company, while a 10% share went to the English giant.

of legislation for investments that the government is soon expected to approve. We are also working through the Supreme Committee to give an executive perception to this ambitious project, in collaboration with its ministries and state agencies, in order to initiate the implementation process. I think that we are moving in the right direction and we will not be working alone. We have a big market, as well as good facilities and infrastructure. We are also ready to cooperate with the private sector.

The discovery of the Zohr gas field was a testing ground for the use of new and increasingly sophisticated exploration technologies. Do you think it is right to proceed along the technology-sharing path on a regional level?

The discovery of the Zohr gas field has proven that adopting new exploration models can lead to exceptional results. Considering the cutting-edge technologies and the operational approaches used for this successful exploration, this discovery has acquired even greater value since it originated in Egypt. So, I think that the energy potential of the region and of the Mediterranean basin has been released in some way and at the same time I believe that the new technologies make a difference and enable potential resources to turn into concrete results. Proof of this is the announcement of new rounds of bids by all neighboring countries. This is an era of new technologies and new exploration models.

What collaborations have you launched with Eni and how do you expect these collaborations to continue in the future?

Our collaboration with Eni started many years ago. The company has been our strategic partner since 1954, so they have been with us in Egypt for over 60 years. Eni is working in all the most important areas in the country, in the Western Desert, in the Eastern Desert, in the Sinai, in the Gulf of Suez, and offshore. The company has an excellent understanding of the context, the operating environment and the business models in Egypt. I genuinely believe this cooperation will continue for many years to come. We are very happy and proud of this partnership, and we hope to develop it further in all sectors, in the upstream and downstream, and even midstream.

The Arab Fund for Economic and Social Development will provide approximately $80-85 million for the reconstruction of a photovoltaic plant in the Egyptian governorship of Aswan. How important is the development of alternative resources for your country's energy mix?

This is something that we are focusing a lot of attention on. The use of fossil fuels as a primary energy source is not sustainable. Therefore, along with our colleagues at the Ministry of Energy and Renewable Resources, we have adopted a strategy for 2035 with which we aim to increase the renewable component of the energy mix from its current level (9 percent) to up to 30 percent by 2035. Doing so, we will move towards the introduction and expansion of other renewable resources, such as wind and solar power. This will help us to achieve the energy mix the country needs and will also reduce the amount of fuels used in energy production. It is therefore a positive intervention for all. We have to work hard and we are adopting and implementing some of the policies approved by the government, and the Ministry of Energy and Renewable Resources is implementing some policies to encourage investment in renewable resources. At the same time, we have plans for combined-cycle energy production, rather than simple open-cycle plans, so as to improve efficiency. We are all working together through this very comprehensive energy strategy that was approved by the Supreme Council of Energy a few months ago.

Analysis/The objectives and tactics behind major energy agreements

An Effective Tool?

Mergers and Acquisitions can accelerate growth, allow quick entry into a country or sector, provide access to new technology or human capital, or help to stave off rivals. Given the movement away from fossil fuels, however, the question of whether they make sense for today's energy behemoths is worth considering

MOISÉS NAÍM

He is a distinguished Fellow at the Carnegie Endowment for International Peace, in Washington, D.C. and a member of **we**'s editorial board. His most recent book is *The End of Power*.

Mergers and Acquisitions in the energy sector are not that different from those in other capital-intensive, global industries. They are driven by the desire to accelerate growth, to achieve a quick entry into a country or sector deemed to be of strategic importance, or to gain access to a new technology or scarce human capital. Sometimes, these large deals are also used as defensive measures as they seek to raise the barriers to entry for new competitors or limit the market power of existing rivals. Given the large size of the leading players in the energy industry, it is only natural that many of the mega-deals of the last decade have taken place in this sector. But the size and the nature of these deals point to an interesting question: why would so many of the big deals in the energy industry seem to be going against the trends that most experts think will define the industry? While there is a debate about the speed at which reliance on fossil fuels to produce energy will decline, there is little disagreement that in the future the world will use less of these fuels. Yet, the pattern of Mergers and Acquisitions in the energy industry during the last 15 years doesn't seem reflect this trend. The main goal of most of the big deals among oil, gas and coal companies is to increase the proven reserves of the acquiring company or of the corporate entity resulting from the merger. Boosting synergies, economies of scale and production volumes of oil and gas are common drivers of the M&A activity in this sector. Why would the corporate behemoths of the energy industry double–down on fossil fuels, a sector whose weight is bound to decline? One answer is that they are not neglecting to increase their presence in renewables but that the size of the deals is still too small to attract the attention of the general media and the public. In contrast, the large-scale Mergers and Acquisitions in fossil-fuel companies are bound to capture the interest of the media and analysts. But there is more. Many of the mega-deals in the energy sector reflect the race against time faced by this industry's leaders. They need to maximize their capacity to exploit hydrocarbons that in the future may face severely restricted markets, becoming in fact stranded assets. The "big-deals" we have seen in the fossil fuel industry are allowing the market leaders to quickly boost their oil and gas reserves rather than having to go through the lengthy process of exploring for new reservoirs and eventually developing them. For example, the average cost of finding and developing new oil and gas reserves in the United States is roughly twice as much as that of acquiring reserves through mergers or corporate acquisitions. This goal of quickly expanding reserves explains much of what's behind the whopping USD 3 trillion worth of Mergers and Acquisitions that we have seen in the last 15 years in this industry. That is why in the league tables of the world's largest M&A the energy industry ranks first.

M&A: When they take place

1 For easy access to industry-leading technologies.
Example: the acquisition of Cameron, for USD 16 billion, by Schlumberger in 2016. Paal Kibsgaard, President and CEO of Schlumberger, defined the deal as a move aimed at uniting Schlumberger's wells and reservoir technology with Cameron's surface and wellhead technology. According to Kibsgaard, the combination of these resources with Schlumberger's strengths in terms of instrumentation, software and automation gave the company a considerable technological advantage.

2 To create a single energy giant in a country.
Example: in India, the government envisages the formation of a single energy giant through the merger of some of the 18-state-owned oil and gas companies currently in existence. The aim is to create a unified company capable of recording revenues of $140 billion and becoming one of the ten major oil and gas companies in the world.

3 To correct major strategic omissions.
Example: ExxonMobil has realized that it needs to invest in hydraulic infrastructure, shifting its strategic direction from conventional oil and gas reserves. By purchasing, this year, 250,000 acres of shale deposits in the Permian Basin, with a $6.6 billion deal, it has become one of the world leaders in the shale industry.

4 To align the company's strategy with market trends, while respecting the environment.
Example: The most significant "big deal" in this context most likely occurred in 2016, with the USD 64 billion acquisition by Shell of BG Group, a company founded 20 years ago by the privatization of British Gas. This transaction has enabled the company to quickly assume a dominant role in the natural gas segment, the preferred transition energy in a global context of reduced carbon dioxide emissions.

Seeking size and efficiency

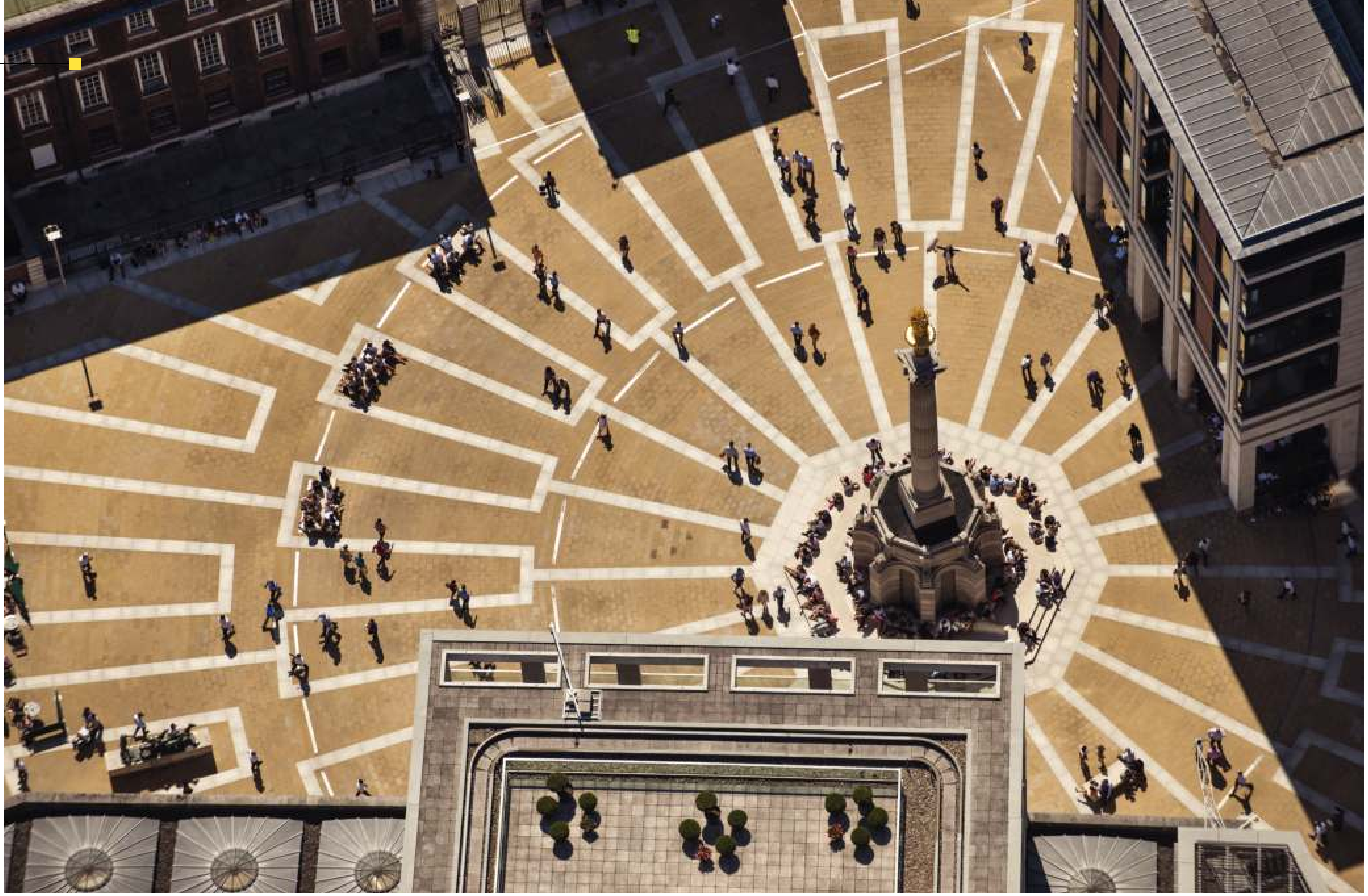
Important examples of this strategy include the case of India, where government plans are advanced to form a single, giant oil company by merging some of the existing 18 state-owned oil and gas companies into a unified corporation that would have revenues of some USD 140 billion and could become one of the world's ten largest oil and gas corporations. This is also the case of Russia, where seven of the ten largest M&A in 2016 took place in the oil and gas sector. Some of these Russian deals also sought to attract more foreign investment into state-owned oil companies. An example of this is the USD 11 billion acquisition of 20 percent of Rosneft made by the Qatar Investment Authority and Glencore, the trading company. In the U.S., the $5 billion merger of Anadarko and Union Pacific that took place in 2000 is another interesting example. Quick access to leading-edge technology is another frequent motivation for M&A. Such was the case in the $16 billion acquisition of Cameron by Schlumberger in 2016. Paal Kibsgaard, Schlumberger Chairman and C.E.O. explained this deal as a move designed to merge Schlumberger's reservoir and well technology with Cameron's wellhead and surface technology. Add that to Schlumberger's existing strengths in instrumentation, software and automation, Kibsgaard held, and you produce a new company with a significant technological edge. The planned acquisition of Baker-Hughes by Halliburton was also triggered by this desire to sustain its technological edge, although the deal ultimately fell through due to anti-trust considerations.

Big deals as a catch-up strategy

Occasionally, companies are driven to rely on acquisitions to correct important strategic omissions. That seems to have been the calculus of ExxonMobil in the case of hydrofracking, the critical set of technologies for the exploitation of shale oil and gas. After having been a latecomer to fracking, the U.S. giant has become one of the world's leaders in this field, thanks to the acquisition this year of 250,000 acres of shale oil deposits in the Permian Basin, located in Texas and New Mexico. This deal, worth USD 6.6 billion, represents the company's largest acquisition since 2009 and a major strategic departure from its reliance on conventional reserves of oil and gas in countries such as Russia, Qatar, Angola and Guyana. Another way in which oil and gas companies are using Mergers and Acquisitions to align their strategies to the trends shaping the industry is through the expansion into more environmentally friendly segments of the business. Perhaps the signature "big deal" of this kind was the 2016, USD 64 billion acquisition by Shell of the BG Group, the company spawned 20 years ago by the privatization of British Gas. This very large deal represented a significant reshaping of Shell's traditional strategy of growth. It was the largest deal ever done by Shell. It was driven by what Gerald Paulides, the leader of the coordinating team, clearly defined as the need to respond to a strategic discontinuity in the energy sector, rather than by the desire to add new traditional oil and gas reserves. Mr. Paulides explained that with this deal, Shell was making a "deliberate move to emphasize the company's strategic goals in certain segments, such as Liquefied Natural Gas." With the BG acquisition, he said, Shell achieved the goal of what could have been a ten year strategy in just one year. Although the acquisition did place Shell as the second largest oil and gas company in the world, its basic motivation was not to increase its size but to quickly become a dominant player in natural gas, the transition energy source of choice as the world moves into a lower carbon energy environment.

Is the oil and gas sector's adjustment to a low carbon economy too slow?

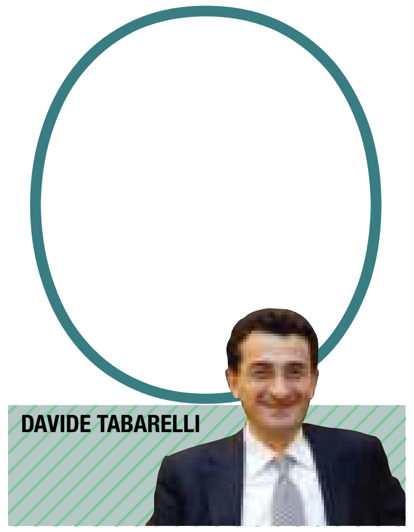
It would seem that large Mergers and Acquisitions by oil and gas companies are emphasizing business as usual, while lagging behind in adjusting to a low-carbon economy. But, is this lag real? Not really. The average size of a merger or an acquisition involving a renewable energy company is comparatively small and thus not as visible as the huge oil and gas deals. The average price tag of a renewable energy company tends to fall under $1 billion. In 2016, corporate Mergers and Acquisitions in wind and solar energy jumped 58 percent to an aggregate USD 27.6 billion. European oil and gas companies are leading in readying the sector for a transition to a low-carbon energy world, mostly through the acquisition of small and medium sized renewable energy companies. Some examples of this trend include TOTAL's strategic decision that calls for one-fifth of its asset base to be focused on low-carbon technologies and the recent creation by Royal Dutch Shell of a New Energy Division. A recent report by Edinburgh based company Wood McKenzie predicts that major energy companies like Royal Dutch Shell, Total S.A, and Statoil, among others, will invest billions of dollars in wind, solar and energy storage projects in the coming decades. Valentina Kretzschmar, Director of Research at Wood Mackenzie, states that such commitments by oil and gas major corporations are due to the fact that they are recognizing renewables as a megatrend, not a passing fad.



Scenario/Learning from the past

No New Wave of Mergers on the Way

Oil prices could still bounce back to $100 a barrel, though that seems an unlikely prospect right now. One thing we can be sure of is that the market will always be unstable; another is that demand is the only factor that matters when defining strategy



DAVIDE TABARELLI

He is chairman and co-founder of Nomisma Energia, an independent energy and environment company based in Bologna. He has always worked as a consultant for the energy sector in Italy and abroad, dealing with all the major aspects of this market. He publishes on major magazines dedicated to energy issues.

On May 15, 1911, the United States Supreme Court found Standard Oil guilty of violating the Sherman Antitrust Act, which had been passed in 1890 but had never been enforced. John D. Rockefeller's company was split into thirty-eight units, including Exxon, Mobil, Chevron and Amoco. Ever since, the oil industry has struggled to reconcile size, which reduces costs but confers market dominance, with fragmentation, which creates uncertainty but favors competition and reduces prices.

Eighty-seven years later, in 1998, oil fell to $10 a barrel. This triggered a wave of mergers, and the two biggest remnants of Standard Oil, Exxon and Mobil, fused to create what is still the biggest private-sector oil company.

Today, two decades later still, prices and profits have been low for more than two years. Supply continues to exceed demand, and we might expect this uncertainty to result in more megamergers.

The Future of M&A lies outside the United States

Mergers and acquisitions have risen in 2017, but these have been marriages of convenience between small to midsized companies, and there is no immediate sign of any major deals like those of yore. In the U.S., the biggest and most profitable market, midyear M&A volumes stood at USD 43 billion, up 35 percent on the USD 35 billion for the whole of 2016.

The spotlight is still on big companies operating outside the country, which show little sign of entering into deals like those of twenty years ago. This is mainly because the context is very different and the prospects less gloomy.

In late 1998 and early 1999, *The Economist* published a detailed review of the energy sector, claiming that the →

MAJOR OIL INDUSTRY ACQUISITIONS, 1995 TO 2016

Source: Data processed by the author

YEAR	ACQUIRER	ACQUIRED	USD billion
1998	Exxon	Mobil	117.3
1998	British Petroleum	Amoco	85.4
1999	Total Fina	Elf Aquitaine	81.5
2015	Royal Dutch Shell	BG Group	70.1
2012	Rosneftegaz	TNK BP	56.5
2000	Chevron	Texaco	52.5
2005	ConocoPhillips	Burlington Resources	42.7
2006	Statoil	Norsk Hydro	35.4
1999	BP Amoco	Atlantic Richfield	35.2
2016	General Electric	BakerHughes	32

-10 10 30 50 70 90 110 130

oil industry was out of date, a tangle of rusty pipes that risked being swept away by the new kind of organization typified by Jeffrey Skilling's Enron. Enron was the new star in the U.S. financial firmament, though its luster was already tarnished. Created in 1985 by merging two gas pipeline companies, Enron grew up during a period of electricity market liberalization and became a major innovator before the dot-com bubble burst. It exemplified the new business model that traditional oil companies could never aspire to, despite the urgings of strategy consultants, because they were too closely tied to physical assets like oilfields, refineries, and petrol pumps. The fact that no one really understood what Enron did was neither here nor there— but then everything became blindingly clear in December 2001, when it became the biggest bankruptcy case in the history of capitalism.

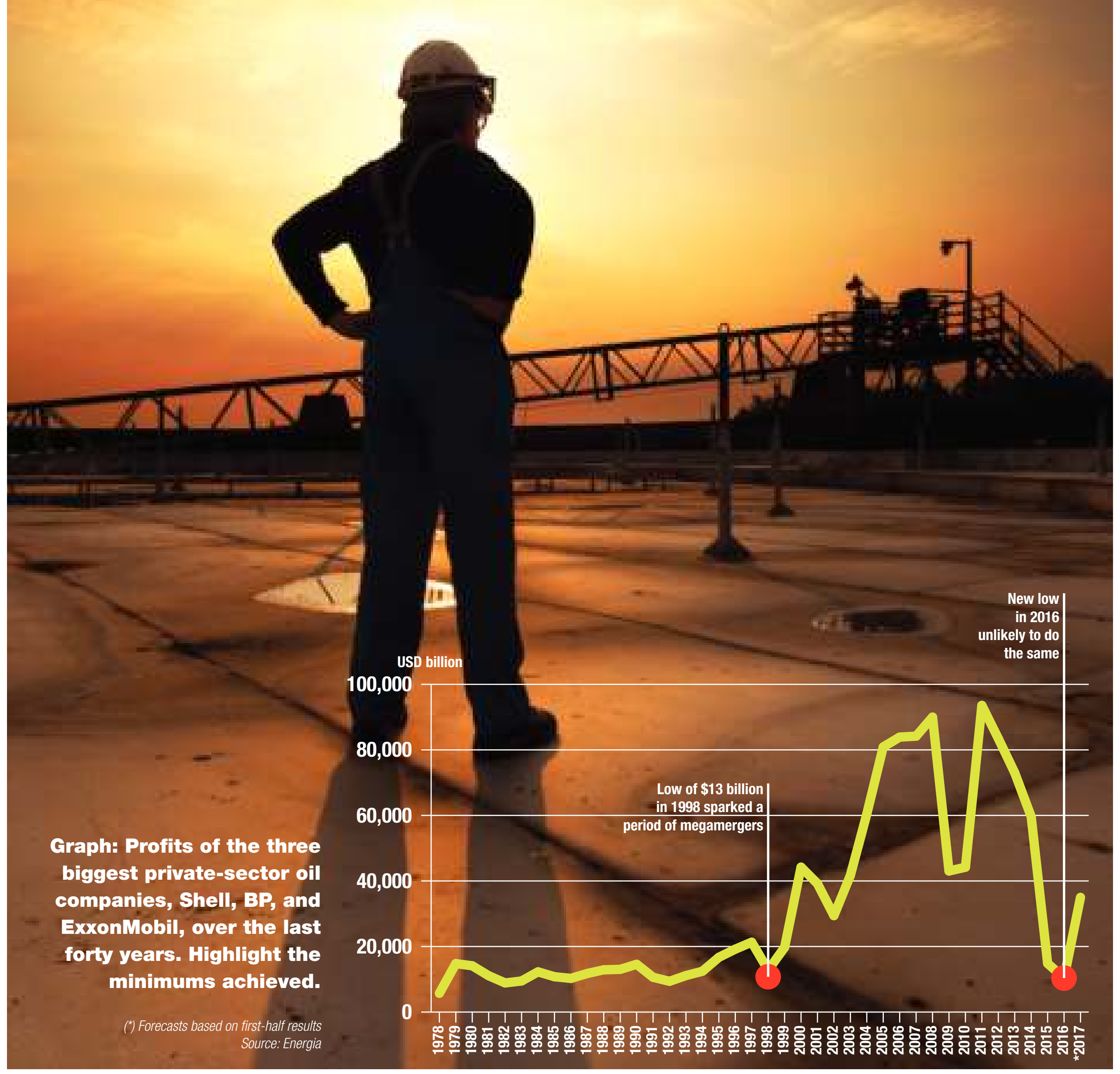
During the confusion of the late 1990s, banks made lots of money from large-scale investment in Enron's high-tech trading. They looked askance at the old oil industry, constantly criticizing its supposed lack of foresight and innovation. The Asian recession of 1998 had reduced demand for oil, and Iraqi output was coming back onstream after the first Gulf war, thanks to the oil-for-food program. This created excess supply, and prices fell to $8 a barrel, the lowest figure in real terms since the 1930s.

One famous *Economist* cover in March 1999 suggested that the world was drowning in oil, as the price fell below $5. Profits slumped, and even the most optimistic forecasts showed prices staying below $30 a barrel for the next twenty years. Huge numbers of people lost their jobs and could be excused for thinking that traditional oil companies had had their day, now that gasoline was cheap, abundant, and sold online. They must have envied their more enterprising or fortunate friends who had gone to work for big-name traders like Enron, or for companies like Edison Mission, Dynegy and Entergy, firms that have since shut down or now serve limited areas of the United States.

Life was not easy for the people running these companies. Profits were low, and analysts were urging them to cut costs and innovate, as some gas and electricity suppliers were doing in the face of competition from energy traders.

The oil industry adapts to a new era

The first company to respond was BP. In August 1998, it acquired its U.S. rival Amoco, another relic of the dismantled Rockefeller empire. This came as a surprise, partly from a financial viewpoint but also because it marked a British incursion into American territory and an industry of strategic importance to the country's energy supply. BP has not always had an easy ride since then, especially when it was forced to pay huge fines following the Deepwater Horizon oil spill in 2010.



Graph: Profits of the three biggest private-sector oil companies, Shell, BP, and ExxonMobil, over the last forty years. Highlight the minimums achieved.

(*) Forecasts based on first-half results
Source: Energia

This opened the floodgates for a series of mergers: most importantly between Exxon and Mobil, then Total and Fina, then Chevron and Texaco. After that, there were none of similar size until 2015, when Shell acquired BG Group (BG) after eyeing it for over a decade. However, this was more an acquisition of complementary operations, mainly in the gas sector, which gained it political support in Great Britain and allayed the concerns of the antitrust authorities. The takeover was also eased by BG's growing difficulty in making the transition from British monopoly to major international company.

The 2014 collapse in crude prices squeezed the huge profits of companies that had once charged more than $100 a barrel. The long-term fortunes of the three biggest, Shell, BP and ExxonMobil, matched those of the industry as a whole, accounting for 70 percent of total earnings by the big six private companies, which also included Eni, Total and Chevron. Their combined earnings fell from a peak of almost $100 billion to just $11 billion in 2016, a record low in real terms. This put huge pressure on their costs, with the losers being the service providers managing major projects for them.

One of the biggest changes over the past twenty years has been the oil companies' gradual outsourcing of production, which began after the first price crash in 1986. Partly thanks to the rise of the finance sector, they have become leaner, concentrating on their traditional core business of geological exploration and paying other companies to build their production infrastructure. They still have quite a lot of refining capacity, but this is the weakest link in the integrated supply chain, with relatively high costs and low profits. This is a legacy of the past: no oil company has built any new refineries in its existing markets, and some have been shut down.

Big Oil becomes more agile

Oil companies have become more flexible since 2014, with less infrastructure and lower costs – though this is partly down to reduced business volumes and outsourced market risk. The biggest loser has been the service sector. Not surprisingly, this is where the biggest oil industry merger of 2016 took place: the $32 billion fusion between General Electric's oil and gas operations and Houston-based Baker Hughes. The latter company had tried to merge with Halliburton in 2014 as oil prices began to collapse, but this move was thwarted when U.S. and European antitrust authorities objected that there was too much overlap between the two companies' services. This was not a problem for the 2016 merger since GE specialized in compressors and Baker in wells.

In August 2017, Total acquired the oil operations of the $40 billion Danish conglomerate Maersk, which specialized mainly in seafreight and shipbuilding, for $7.5 billion in shares and debt. Total had been expanding fast for several years. Maersk needed to rationalize: it was in difficulty thanks to low demand for freight services and declining charter income. Total used the acquisition to increase its output, with an ambitious target of 3 million barrels of inhouse production a day, and thereby achieve economies of scale.

The wave of mergers that followed the last oil-price crash in 1998 is unlikely to recur because today it is clear that prices could quickly bounce back toward $100, distant prospect though this might seem at the moment. In 2013, when global demand was less than six million barrels a day, no one could have dreamed that oil would cost $50 a barrel within three years. Market instability is the only certainty, which makes life difficult in an industry that invests billions of dollars in projects with payback periods of up to fifty years. The only real factor in defining strategy, whether for mergers or anything else, is the demand for oil. And demand is growing, whatever short-term financial ups and downs the industry may experience.

#deals

Africa, Europe, Russia and Caspian, United States, Canada, Latin America, Australia and Oceania: the world is changing at a pace of the great energy agreements. We analyze, area by area, as the economy is redesigning life on the planet.

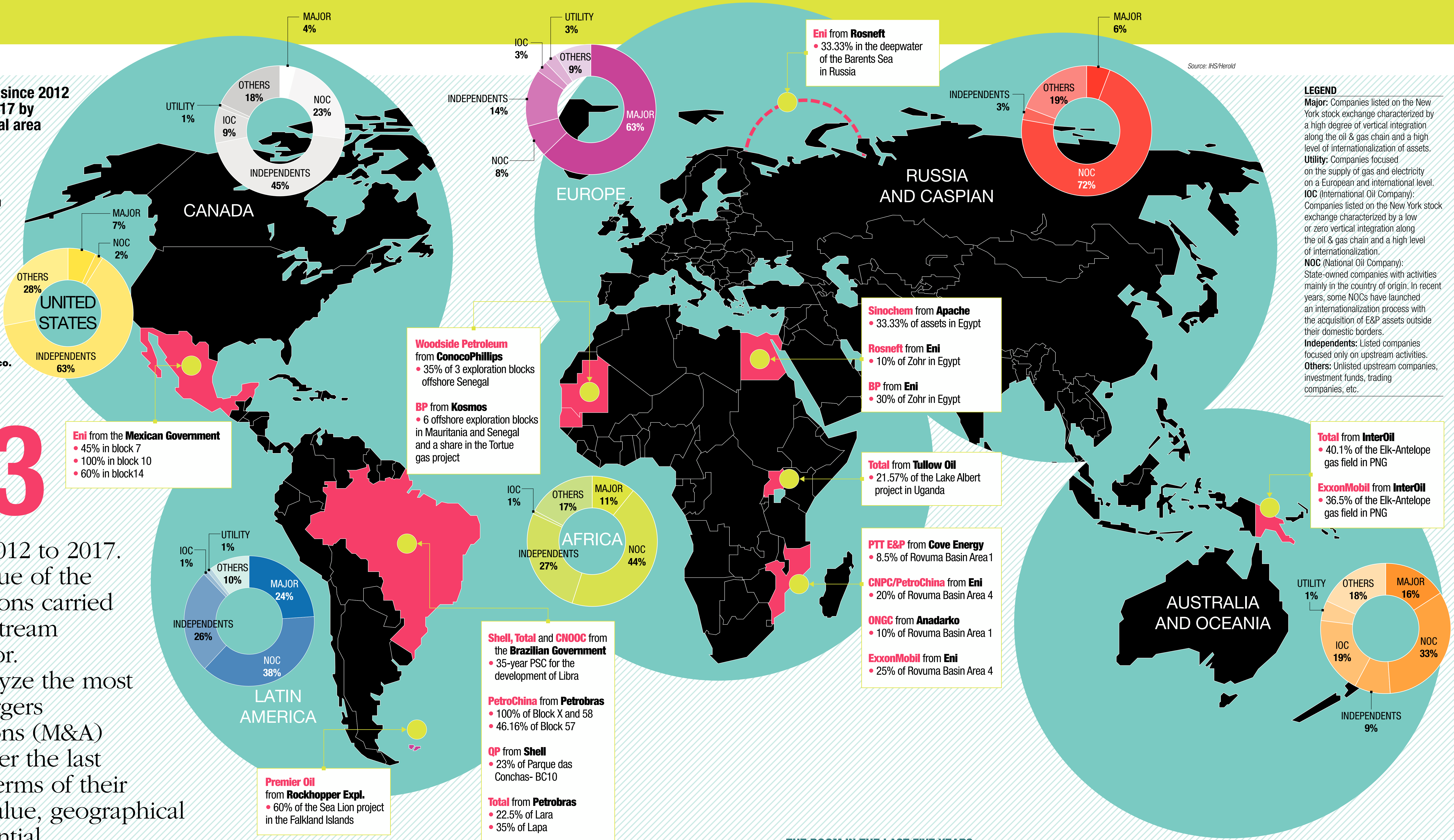
Upstream M&A activity since 2012 as of the first half of 2017 by cluster and geographical area

THE DEALS THAT WILL DETERMINE THE FUTURE

Over the last five years, upstream transactions geared towards productive growth have been focused on Africa and Latin America, first and foremost, the major gas discoveries in Mozambique and Egypt and the major oil discoveries in Brazilian deepwater (pre-salt). However, the launch of new exploration campaigns took place in Senegal/Mauritania and Mexico.

1,013

billion from 2012 to 2017. This is the value of the main transactions carried out in the upstream oil & gas sector. Here, we analyze the most important Mergers and Acquisitions (M&A) carried out over the last five years in terms of their commercial value, geographical area and potential.



Source: IHS/Herold

Eni from the **Mexican Government**
- 45% in block 7
- 100% in block 10
- 60% in block14

Woodside Petroleum from **ConocoPhillips**
- 35% of 3 exploration blocks offshore Senegal

BP from **Kosmos**
- 6 offshore exploration blocks in Mauritania and Senegal and a share in the Tortue gas project

Eni from **Rosneft**
- 33.33% in the deepwater of the Barents Sea in Russia

Sinochem from **Apache**
- 33.33% of assets in Egypt

Rosneft from **Eni**
- 10% of Zohr in Egypt

BP from **Eni**
- 30% of Zohr in Egypt

Total from **Tullow Oil**
- 21.57% of the Lake Albert project in Uganda

PTT E&P from **Cove Energy**
- 8.5% of Rovuma Basin Area 1

CNPC/PetroChina from **Eni**
- 20% of Rovuma Basin Area 4

ONGC from **Anadarko**
- 10% of Rovuma Basin Area 1

ExxonMobil from **Eni**
- 25% of Rovuma Basin Area 4

Total from **InterOil**
- 40.1% of the Elk-Antelope gas field in PNG

ExxonMobil from **InterOil**
- 36.5% of the Elk-Antelope gas field in PNG

Shell, Total and **CNOOC** from the **Brazilian Government**
- 35-year PSC for the development of Libra

PetroChina from **Petrobras**
- 100% of Block X and 58
- 46.16% of Block 57

QP from **Shell**
- 23% of Parque das Conchas- BC10

Total from **Petrobras**
- 22.5% of Lara
- 35% of Lapa

Statoil from **Petrobras**
- 66% of the exploration license for block BM-S-8

Premier Oil from **Rockhopper Expl.**
- 60% of the Sea Lion project in the Falkland Islands

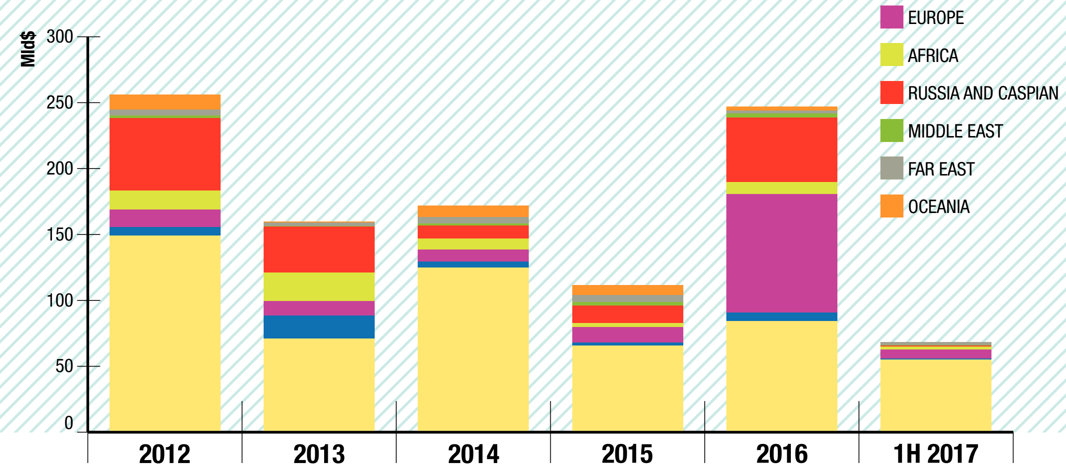
LEGEND

Major: Companies listed on the New York stock exchange characterized by a high degree of vertical integration along the oil & gas chain and a high level of internationalization of assets.
Utility: Companies focused on the supply of gas and electricity on a European and international level.
IOC (International Oil Company): Companies listed on the New York stock exchange characterized by a low or zero vertical integration along the oil & gas chain and a high level of internationalization.
NOC (National Oil Company): State-owned companies with activities mainly in the country of origin. In recent years, some NOCs have launched an internationalization process with the acquisition of E&P assets outside their domestic borders.
Independents: Listed companies focused only on upstream activities.
Others: Unlisted upstream companies, investment funds, trading companies, etc.

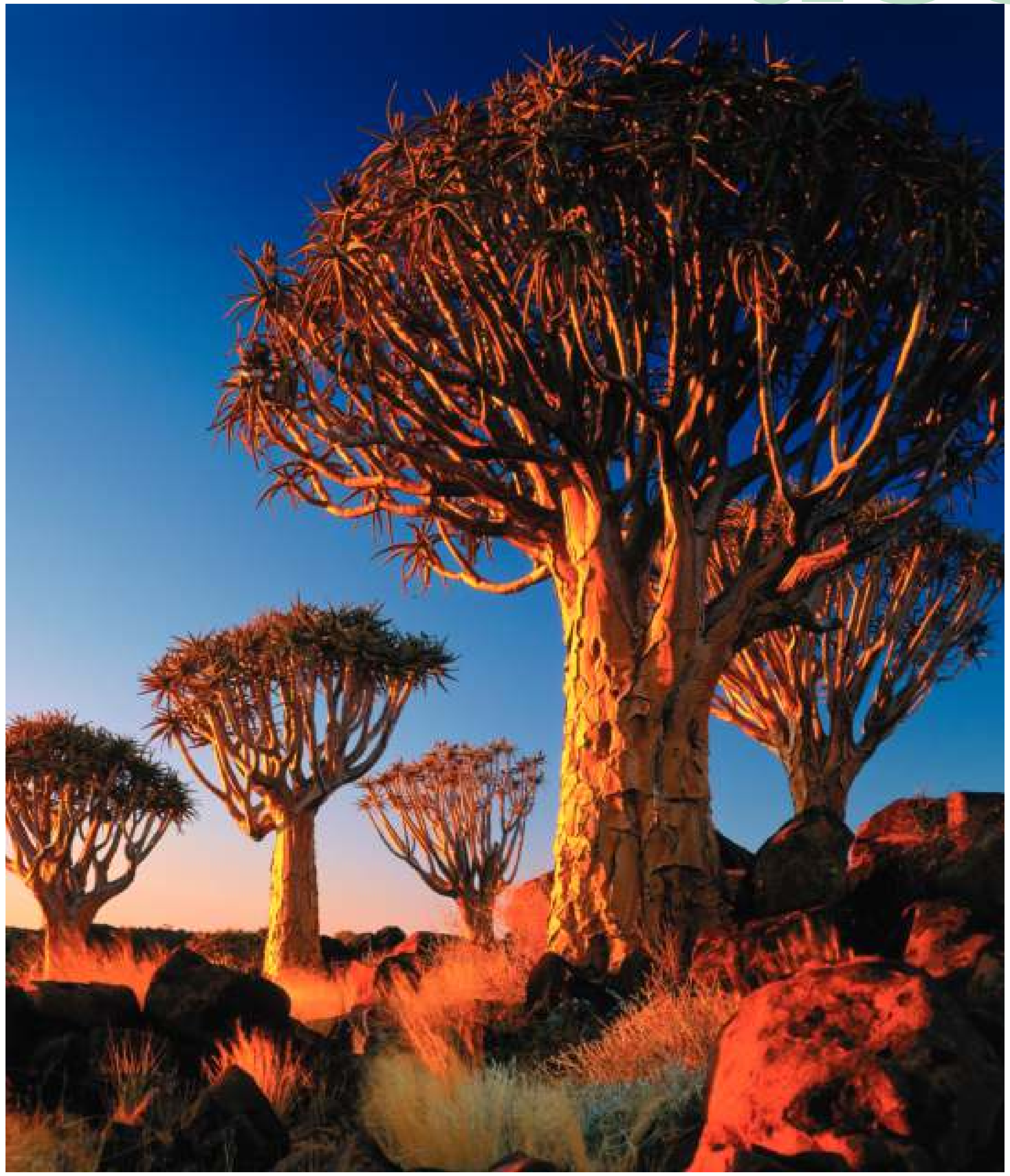
THE BOOM IN THE LAST FIVE YEARS

Acquisitions in the global upstream sector have seen a boom in recent years. In 2016, the value of global upstream deals doubled, increasing to USD 245 billion from USD 110 billion in 2015. Acquisitions in the first half of 2017 totalled USD 70 billion.

Upstream M&A since 2012 as of the first half of 2017 by economic value



A big Bu$iness


#deals



A Land of Challenges/A region of strong potential

Major Asset Deals on the Horizon

The continent has suffered from a fall in investments in mining and production activities since the downturn in oil prices. Now, however, there is a return to investment in many African countries, although at a level still far below its 2013 peak, when deals topped USD 21.5 billion

MARK SMEDLEY

Oil and gas reporter, he is working as editor of the magazine *World Gas Intelligence*. Since early 2016 he has been Africa editor for *Natural Gas World* where he also writes about LNG projects & trade, and the European gas market.

Think of the huge Zohr gas discovery offshore Egypt's Nile Delta, the huge gas resources found in the deep waters off Mozambique, the significant Ugandan oil reserves still untapped in Africa's interior and the oil and gas prospects being appraised offshore Mauritania and Senegal. All involved skilled geologists using the latest technology, but essentially represented an astute bet that reserves would be found outside Africa's traditional producing centers of Algeria, Angola and Nigeria. Some companies in certain countries have found the sweet spots: Eni in offshore Egypt, Eni and Anadarko off Mozambique, UK-based Tullow Oil in Uganda, and U.S. independent Kosmos in Senegal/Mauritania.

For others, offshore Namibia and Liberia for instance, the quest has been elusive. Meanwhile exploration capital expenditure, pruned significantly in 2014-15, is only slowly recovering.

Egypt's Zohr and deepwater Mozambique

The big value transactions of 2016-17 can be seen as paybacks for yesteryear. They include Eni's 2016 divestments of stakes in its own discoveries: 10 percent and later 30 percent of the supergiant Zohr field offshore Egypt to, respectively, BP (USD 525 million) and Russian giant Rosneft (USD 1.6 billion) plus a 25 percent interest in Mozambique's offshore Area 4 for USD 2.8 billion to ExxonMobil, announced March 2017 though still to be completed. At Zohr there is additional potential upside for Eni in that BP and Rosneft have options to buy a further 5 percent equity each in the supergiant field—in which case Eni's equity stake in Zohr will fall to 50 percent. Eni as operator expects Phase 1 of Zohr to begin producing at 1 billion cubic feet (bcf) per day later this year, less than 30 months after its discovery, increasing to 3 bcf/d by late 2019, which will enable Egypt to generate gigawatts of power from local gas. Zohr has 30 trillion cubic feet (tcf), or 850 billion cubic meters (bcm) of gas in place and its full development could cost partners USD 12 billion. While there have been earlier farm-downs offshore Mozambique, the last 18 months has seen only ones by Eni in Area 4, with partners in Anadarko-operated Area 1 sitting tight on their 75 tcf (2.1 tcm) recoverable gas resources. Area 4's resources are 85 tcf (2.4 tcm), of which Eni will retain a 25 percent interest even after the sale to Exxon is complete. Rosneft and Exxon, meanwhile, remain partners in 3 deepwater licenses acquired in Mozambique's 2015 licensing round.

Senegal and Mauritania, evolving mining and production

BP agreed to pay USD 916 million in cash and carried expenses in late 2016 to Kosmos in return for roughly 30 percent interests in the latter's six Senegal/Mauritania offshore blocks and a share in the Tortue deepwater floating LNG venture that is expected to take a Final Investment Decision (FID) in 2018 and export its first LNG in 2021. There is further upside for Kosmos in the BP transaction if oil prices rise. Greater Tortue holds 25 tcf (708 bcm) of gas at 100 percent equity, says Kosmos, with a potential increase to more than 50 tcf (1.41 tcm) of gas. This May, Kosmos announced the Yakaar-1 gas discovery of 15 tcf off Senegal—potentially enough for a second Floating Liquefied Natural Gas (FLNG) project with BP—call- →

Leader in Energy Discoveries

The chart above attests to the role of the great protagonist that the African continent has covered in recent years, with regard to energy discoveries, over the rest of the world. It is a primacy, however, which has not always paid for the exploitation and distribution of the identified resources.

2012	
Africa	10.71
Americas	3.96
Asia	1.84
2013	
Africa	3.23
Americas	1.92
Asia	0.71
Australia	0.22
Middle East	0.92
Europe	0.57
Unspecified	0.32
2014	
Africa	2.23
Americas	0.99
Asia	0.96
Australia	0.2
Middle East	0.19
Europe	0.31
Oceania	0.15
2015	
Africa	6.68
Americas	1.82
Asia	0.4
Australia	0.3
Middle East	0.13
2016	
Africa	1.86
Americas	0.22
Asia	0.32
Europe	0.3
Middle East	0.7

Values expressed in millions of barrels of equivalent oil and gas

Source: PricewaterhouseCoopers

2016
1. Woodside Petroleum from ConocoPhillips • 0.30 Bln $ • 35% of 3 offshore mining blocks in Senegal
2. BP from Kosmos • 0.90 Bln $ • 6 offshore blocks in Mauritania/Senegal and a share in the Tortue deepwater gas project
3. BP from Eni • 0.50 Bln $ • 10% of Zohr (Egypt)
4. Rosneft from Eni • 1.60 Bln $ • 30% of Zohr (Egypt)
5. ExxonMobil from Eni • 2.80 Bln $ • 25% of area 4 in Mozambique
6. Pertamina from Maurel & Prom • 1.10 Bln $ • 24.5% acquisition of Maurel & Prom (assets in Nigeria Gabon and Tanzania)
7. Geron Energy from San Leon • 0.50 Bln $ • Acquisition of San Leon (OML18 and several mining assets)

2017
1. Total from Tullow Oil • 0.80 Bln $ • 21.57% of the Lake Albert project (Uganda)
2. Assala Energy from Shell • 0.90 Bln $ • Production assets in Gabon

Source: IHS/Herold

2015

2014
1. Al Mirqab Capital from Heritage Oil • 2.00 Bln $ • Assets in various African countries
2. Glencore Xstrata from Caracal Energy • 1.30 Bln $ • 3 Production Sharing Contracts in Chad
3. Chad Governement from Chevron • 1.30 Bln $ • 25% concession in Doba Basin

2013
1. CNPC/PetroChina from Eni • 4.50 Bln $ • 20% Rovuma Basin Area 4 (Mozambique)
2. Sinochem from Apache • 3.10 Bln $ • 33.33% asset in Egypt
3. ONGC from Anadarko • 2.64 Bln $ • 10% Rovuma Basin Area 1 (Mozambique)

2012
1. PTT E&P from Cove Energy • 1.80 Bln $ • 8.5% Rovuma Basin Area 1 (Mozambique)
2. Pertamina from ConocoPhillips • 1.75 Bln $ • Production activities in Algeria
3. Oando Energy Resources from ConocoPhillips • 1.65 Bln $ • Assets in Nigeria

Workers on an offshore oil platform. Most of the major fields in Africa are offshore. The main ones are in Egypt, Mozambique, Mauritania and Senegal.

The Transactions
(Bln $)

		Bln $
2012	1	1.80
	2	1.75
	3	1.65
2013	1	4.50
	2	3.10
	3	2.64
2014	1	2.00
	2	1.30
	3	1.30
2016	1	0.30
	2	0.90
	3	0.50
	4	1.60
	5	2.80
	6	1.10
	7	0.50
2017	1	0.80
	2	0.90

The Main M&A

[2012/2017]

In 2012, transactions in Africa stood at over USD 14 billion; the most significant of these involved the acquisition by PTT E&P of 8.5 percent of Area 1 in the Rovuma Basin (Mozambique), from Cove Energy, for $1.8 billion, the sale by ConocoPhillips of its production activities in Algeria to Pertamina for $1.75 billion and the sale, also by ConocoPhillips, of some assets in Nigeria to Oando Energy Resources for $1.65 billion.

In 2013, M&A transactions exceeded $21.5 billion, due to Eni's sale of 20 percent of Area 4 in the Rovuma Basin (Mozambique) to CNPC/PetroChina for $4.5 billion. Also significant was Apache's sale of 33.33 percent of its Egyptian assets to Sinochem for $3.1 billion and, lastly, Anadarko's sale of 10 percent of Area 1 in the Rovuma Basin (Mozambique) to the Indian state-owned company ONGC for $2.63 billion.

In 2014, acquisitions stood at $8.4 billion. The most significant of these was Al Mirqab Capital's of some African assets of Heritage Oil for $2 billion, followed by Glencore Xstrata's purchase from Caracal Energy of 3 PSCs in Chad for $1.3 billion and, finally, Chevron's sale of 25 percent of the concession in the Doba Basin (Chad) to the government of Chad for $1.3 billion.

In 2016, upstream transactions in Africa nearly doubled, rising to $6 billion from $3.3 billion the year before, with eight deals accounting for 93 percent of the total value. In the first six months of 2017, transactions amounted to $2.4 billion.
Most exploration deals involved West Africa. Woodside acquired 35 percent of 3 offshore exploration blocks in Senegal—Rufisque Offshore, Sangomar Offshore and Sangomar Deep Offshore—from ConocoPhillips for $350 million: meanwhile, BP purchased 6 offshore blocks in Mauritania/Senegal and a share in the Tortue deep-water gas project from Kosmos for $916 million.
Also significant were Eni's divestments of shares in its own gas discoveries: 10 percent and 30 percent of Zohr in Egypt, respectively, to BP ($525 million) and Rosneft ($1.6 billion) and 25 percent of Area 4 in Mozambique ($2.8 billion) to ExxonMobil.
The main corporate M&A were the purchase, by Pertamina of 24.5 percent of Maurel & Prom for $1.1 billion (assets in Nigeria, Gabon and Tanzania) and the acquisition by the Chinese investment group, Geron Energy of San Leon Energy for $492 million (OML18 and numerous exploration assets).

In the first months of 2017, the main African transactions concerned the purchase of 21.57 percent of the Lake Albert project (Uganda) by Total from Tullow Oil for $800 million and the sale, by Shell, of production assets in Gabon for $872 million.

ing it the largest hydrocarbon find in the year to date. Kosmos had a short-list of four bidders during its 2016 offer to farm down these interests, from which it eventually chose BP both on price and suitability criteria. The bidding contest shows the strong interest that Senegal/Mauritania has elicited. But there have also been disputes. Australian independent Woodside acquired ConocoPhillips's 35 stakes in 3 blocks offshore Senegal for USD 350 million in mid-2016. A year later, junior partner Australia's FAR referred Conoco to international arbitration, alleging Conoco failed to follow correct pre-emption procedures. An arbitration ruling is due mid-2018. Cairn, operator of the 3 blocks, has since made its eleventh consecutive oil discovery—all at or near its first find, the SNE field. So, the region has become a hotspot, with firms like Total and China National Offshore Oil Corp (CNOOC) stepping up their involvement in nearby acreage.

Chinese eyes look towards East Africa

Another substantial farm-in was undertaken by Total in Uganda, but it was later pre-empted by partner CNOOC. Tullow agreed in January 2017 to farm-down 21.57 percent of its 33.33 percent interests in the oil-rich Lake Albert project covering areas 1, 1A, 2 and 3A in Uganda to Total for USD 900 million, which would have given the French company a majority 54.9 percent stake in the acreage. But two months later, in March 2017, CNOOC exercised its pre-emption rights under the joint operating agreements between Tullow, Total and CNOOC to acquire half of the interests being transferred to Total in Uganda on the same terms—thus denying Total its majority stake in the venture. Tullow, which will still net USD 900 million, is expected to transfer its operatorship to Total upon completion later in 2017. Lake Albert oil, is a much-anticipated project. Tullow has discovered some 1.7 billion barrels since 2006 and has already raised USD 2.9 billion in 2010-12 by bringing in Total and CNOOC as partners. FID was expected this year. The pre-emption by CNOOC may slow that slightly, but neither Tullow, Total nor CNOOC want to lose the momentum from Uganda's April 2016 announcement that it will help develop a USD 3.55 billion, 1,445 km oil export pipeline to the port of Tanga, northern Tanzania. Meanwhile, Malaysian state Petronas is rumored to be eying a sale of the onshore oil field stakes, which it acquired from Conoco in 2012-13 for USD 1.75 billion.. Indonesia's national oil company Pertamina in late 2016/early 2017 wrapped up the purchase of French→

independent Maurel & Prom for USD 1.1 billion, a deal that included its Gabonese oil and Tanzanian gas production. Chinese investor China Great United Petroleum conditionally offered in late June 2017 to buy UK-listed San Leon Energy, whose main asset is an onshore Nigerian field stake, for over £0.3 billion.

Europe still remains at the window

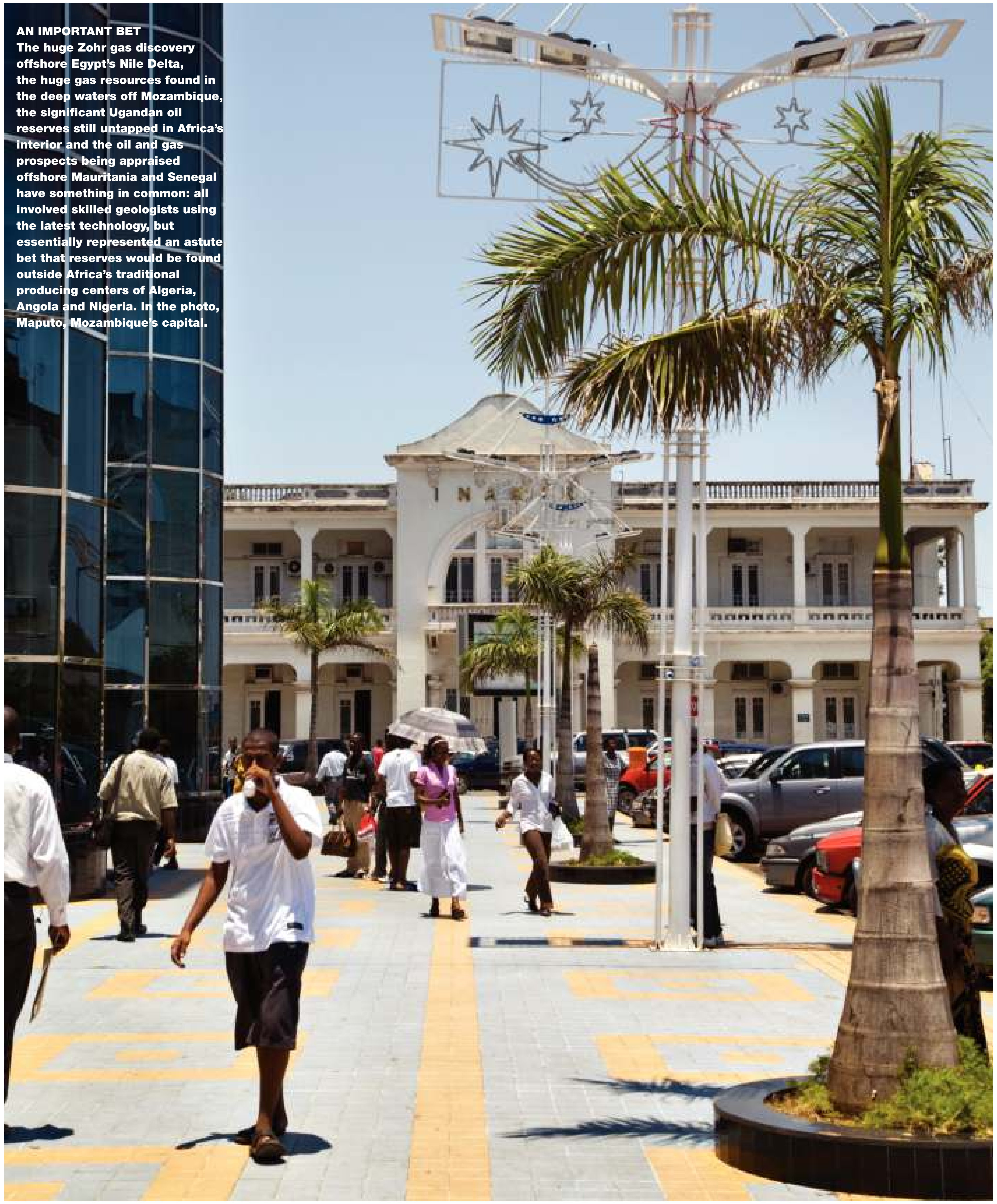
Conoco quit Senegal to pay down debt, and European firms have taken similar actions.

Shell's USD 54 billion acquisition of BG, completed in early 2016, led it to announce plans to divest USD 30 billion of assets, one of which was oil production in Gabon announced for sale in March 2017 to U.S. Carlyle Group's upstream arm CIEP for USD 854 million, including USD 285 million debt. Key BG assets that Shell has retained for now, though, include its 60 percent interest in Tanzania's gas-rich blocks 1 & 4. However, there have been unconfirmed reports that Shell might be seeking a buyer for its Tunisian E&P gas assets. In May 2017, Carlyle said its part-owned Neptune Energy business is in detailed talks with France's Engie to acquire the latter's 70 percent stake in Engie E&P for USD 3.9 billion, most of whose assets are in Europe or Asia. Engie will retain about half (currently 65 percent) its E&P interest in the Touat gas field development of southwest Algeria, due to start production jn 2018 and plateau at 4.5 bcm/year.

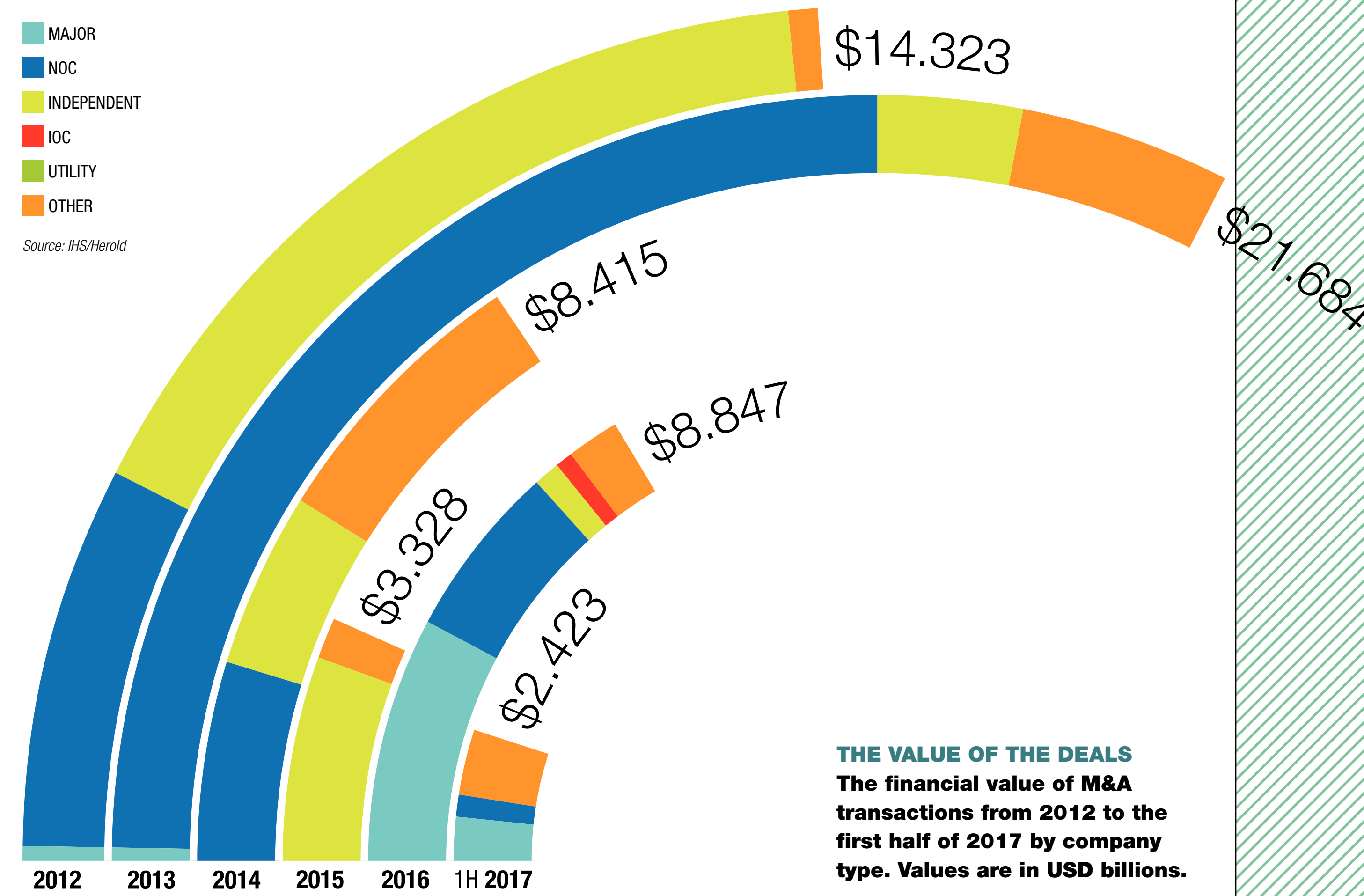
The sale of Maersk Oil, announced this August by Danish parent AP Moller-Maersk to Total for USD 7.45 billion in a share and debt deal, is scheduled to be completed in the first quarter of 2018. While most (85 percent) of Maersk's Oil assets are in Europe, it has stakes in Anadarko-operated oilfields onshore Algeria and also the Chissongo oilfield offshore Angola where Maersk (operator, 65 percent) chose in early 2016 to defer development. Total CEO Patrick Pouyanne hinted his firm may be better placed to proceed with Chissongo, as Total "operates 40 percent of Angolan production" and has "a strong relationship with Sonangol."

Uncertainties remain regarding the Western front

A deal struck in August of 2015 collapsed in 2016: the USD 1.75 billion sale by U.S. independent Cobalt of its 40 percent stake in Angolan oil and gas-rich deepwater blocks 21/09 and 20/11 to state Sonangol. In May 2017, Cobalt referred the case to arbitration and is claiming USD 2 billion damages from Sonangol. BP this July wrote down an Angolan gas find, Katambi, and stakes in the same Cobalt blocks by USD 750 million,



AN IMPORTANT BET
The huge Zohr gas discovery offshore Egypt's Nile Delta, the huge gas resources found in the deep waters off Mozambique, the significant Ugandan oil reserves still untapped in Africa's interior and the oil and gas prospects being appraised offshore Mauritania and Senegal have something in common: all involved skilled geologists using the latest technology, but essentially represented an astute bet that reserves would be found outside Africa's traditional producing centers of Algeria, Angola and Nigeria. In the photo, Maputo, Mozambique's capital.



THE VALUE OF THE DEALS
The financial value of M&A transactions from 2012 to the first half of 2017 by company type. Values are in USD billions.

as it saw no prospects for any near-term commercial development. Nigeria, like Angola, has seen its oil and gas revenues fall steeply since 2014-15 and has also been afflicted by 2016-early 2017 militant attacks in the Niger Delta region that stalled a much hoped-for influx of private investment into new gas-fired power plants. This happened just as falling LNG export prices were giving producers more incentive to sell gas into the domestic market, where prices were firming.Unlike Angola, Nigeria retains a resilient private sector E&P base, and this has soldiered on during the lean times. This summer, U.S. giant Schlumberger agreed to commit USD 700 million of investment to oilfields operated by Nigeria-owned First E&P. Nigeria's Seven Energy is now in talks over a possible acquisition of UK-listed Savannah Energy's exploration assets in neighboring Niger.

The LNG situation and the midstream sector

One interesting industry development was Schlumberger's July 2016 decision to farm into a joint venture, OneLNG, that seeks to develop low-cost gas reserves into LNG. Golar LNG will retain a majority 51 percent interest in OneLNG, but Schlumberger will provide capital and own 49 percent equity.

Golar's particular appeal is that it has pioneered a floating LNG (FLNG). a new approach to liquefying and thus monetising stranded gas, a process especially useful in Africa where large onshore liquefaction projects and expansions over the past decade have all stalled. In autu million 2017, as a ship provider, it will launch Africa's first FLNG venture offshore Cameroon, a project operated by UK-French firm Perenco.

In late 2016, OneLNG and UK independent Ophir signed a shareholders' agreement to jointly develop a FLNG project offshore Equatorial Guinea dubbed Fortuna, with OneLNG holding 66.2 percent and Ophir 33.8 percent. No cash transaction was reported, but expenditure on Fortuna FLNG will be roughly USD 2 billion, with OneLNG expected to carry at least its equity share. FID is due later this year for a planned 2020 start-up, and it will be Africa's second FLNG venture (following Cameroon) and ahead of Eni's 3.4 million mt/yr Coral FLNG offshore Mozambique that took FID this June but will not start exports until 2022.

Africa is also seen as a promising place for floating LNG import schemes based on Floating Storage and Regasification Units (FSRU) and maybe later LNG-to-power projects. Ghana has three such FSRU projects to import LNG, but two are stalled, including one for more than 15 months. Total hopes to launch an FSRU-based venture in Cote d'Ivoire in 2018 with six co-investors including Shell and Azeri state Socar. Egypt has operated FSRUs since 2015, chartered from ship owners Hoegh LNG and BW Gas, but it will probably not retain these engagements post-2020, as it will have more than sufficient indigenous gas once the giant Zohr starts production later in 2017 and ramps up steeply in 2019. At the oft-jilted Kudu gas field offshore Namibia, Singapore-based shipowner BW Offshore is to decide this 4th quarter 2017 whether to earmark one of its floating production vessels (FPSOs) to develop gas that would be piped ashore to generate electricity in Namibia for export to South Africa. BW would earn a 56 percent interest in Kudu, with state Namcor keeping 44 percent of all previous stakeholders having exited Kudu as uncommercial. Namibia is eying LNG imports based on an FSRU if Kudu fails.

Asset deals in the field of refining

Glencore announced October 6 a proposal to buy a 75 percent interest in Chevron's South African downstream oil joint venture that includes a 100,000 b/d refinery at Cape Town for $973mn; the deal – replacing an earlier planned sale to China's Sinopec that stalled – would also give Glencore a downstream presence across South Africa and neighbouring Botswana. Total also expanded its filling station network in East Africa earlier in 2017 through a much smaller transaction.

Europe

#deals

At the Edge of the Pole/The race to the Eldorado beneath the ice

A New Arctic Era

Oil&gas production in the northern areas of the old continent is considered a long-term investment, its viability and profitability vary greatly depending on the costs of retrieving the estimated resources and future expectations of oil and gas prices

ANDREAS RASPOTNIK AND MARCO SIDDI

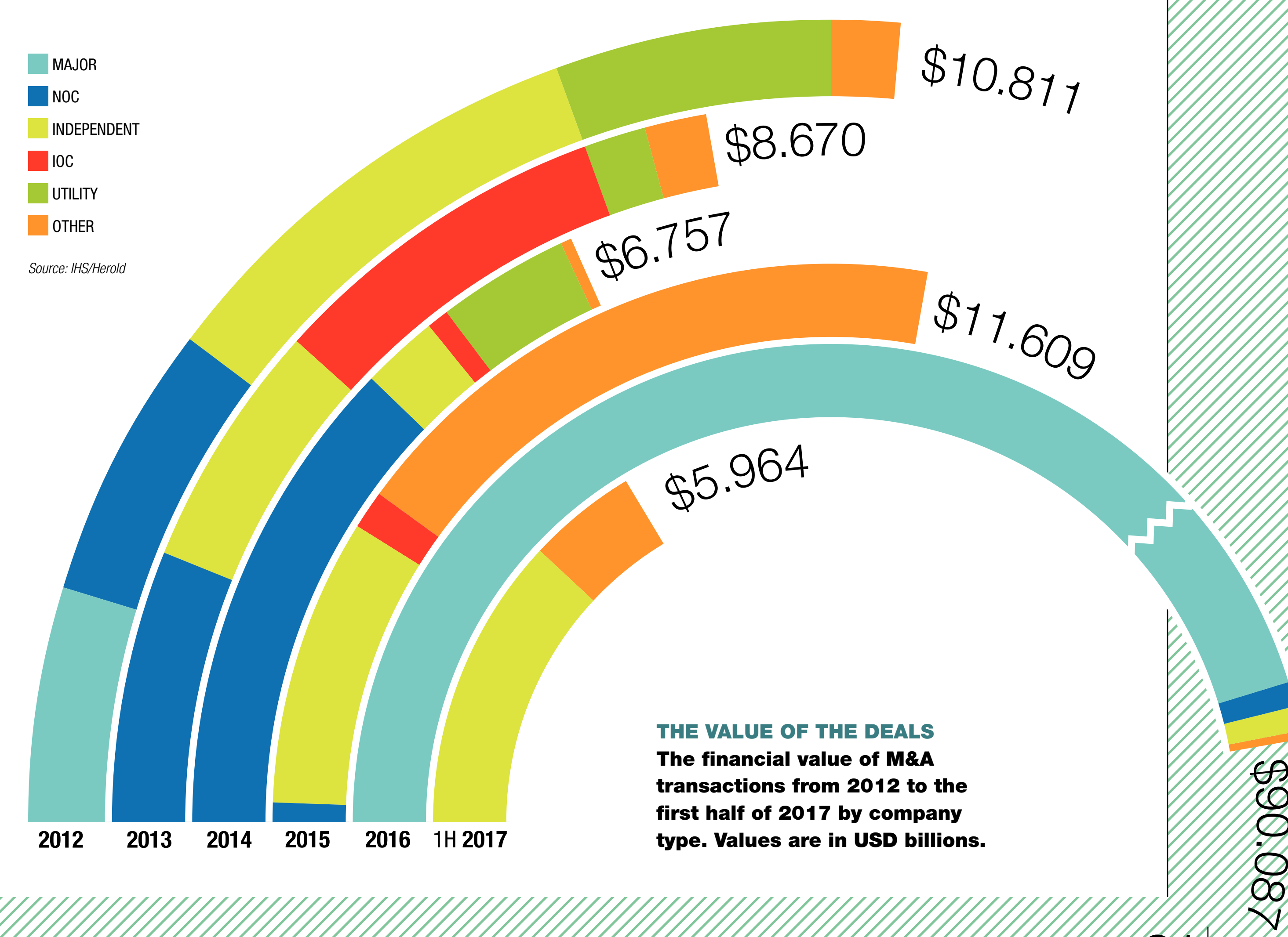
Andreas Raspotnik is a Senior Fellow and Member of the Leadership Group at The Arctic Institute, Center for Circumpolar Security Studies in Washington, DC.

Marco Siddi is Senior Research Fellow at the Finnish Institute of International Affairs in Helsinki, where he focuses on EU-Russia relations and energy politics.

A decade ago, during the summer of 2007, the Arctic region reappeared as a center of world politics. It famously hit global headlines in August 2007 with a blurry picture of a Russian titanium flag, planted more than 4,000 meters beneath the North Pole at the bottom of the Arctic Ocean. Earlier that summer, Greenland—the world's largest island—became the "mecca of climate tourism" when the President of the European Commission, José Manuel Barroso, Italian Prime Minister Romano Prodi and German Chancellor Angela Merkel experienced global warming and the melting of Greenland's ice sheet first hand. And in September 2007, images of an ice-free Arctic Ocean ruled the airwaves as the extent of the Ocean's sea ice reached a record low. It was a period when global climate change captured public interest. The region's (sea) ice was disappearing; and with the melting of the north polar ice cap the "solid state" of the Arctic was called into question. Eventually, the region became a matter of international discussion. Ironically, the very melting of the Arctic ice yielded commodities that have essentially contributed to the ice's decline in the first place: fossil fuels. In 2008, the U.S. Geological Survey published an evaluation of the oil and gas resource potential north of the Arctic Circle. It indicated that the region may contain 22 percent of the world's undiscovered conventional oil and natural gas resources—numbers that created public hype with forecasts of a new "Arctic Gold Rush." It was further estimated that the Eurasian continent holds about 63 percent of the total resources (mainly gas-prone) while the North American continent holds about 35 percent (rather oil-prone).

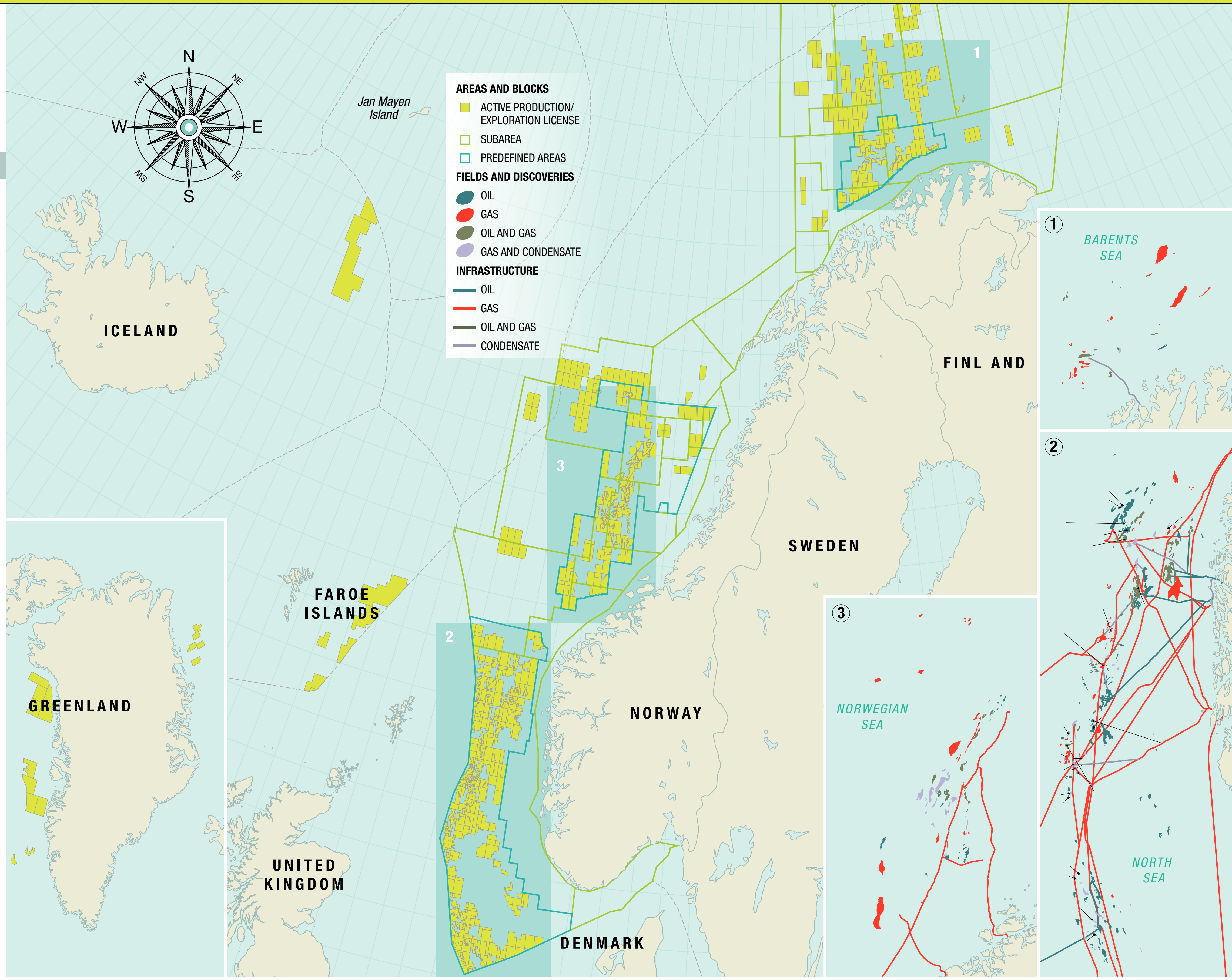
Oil&gas reserves in the Barents, Pechora and Kara Seas

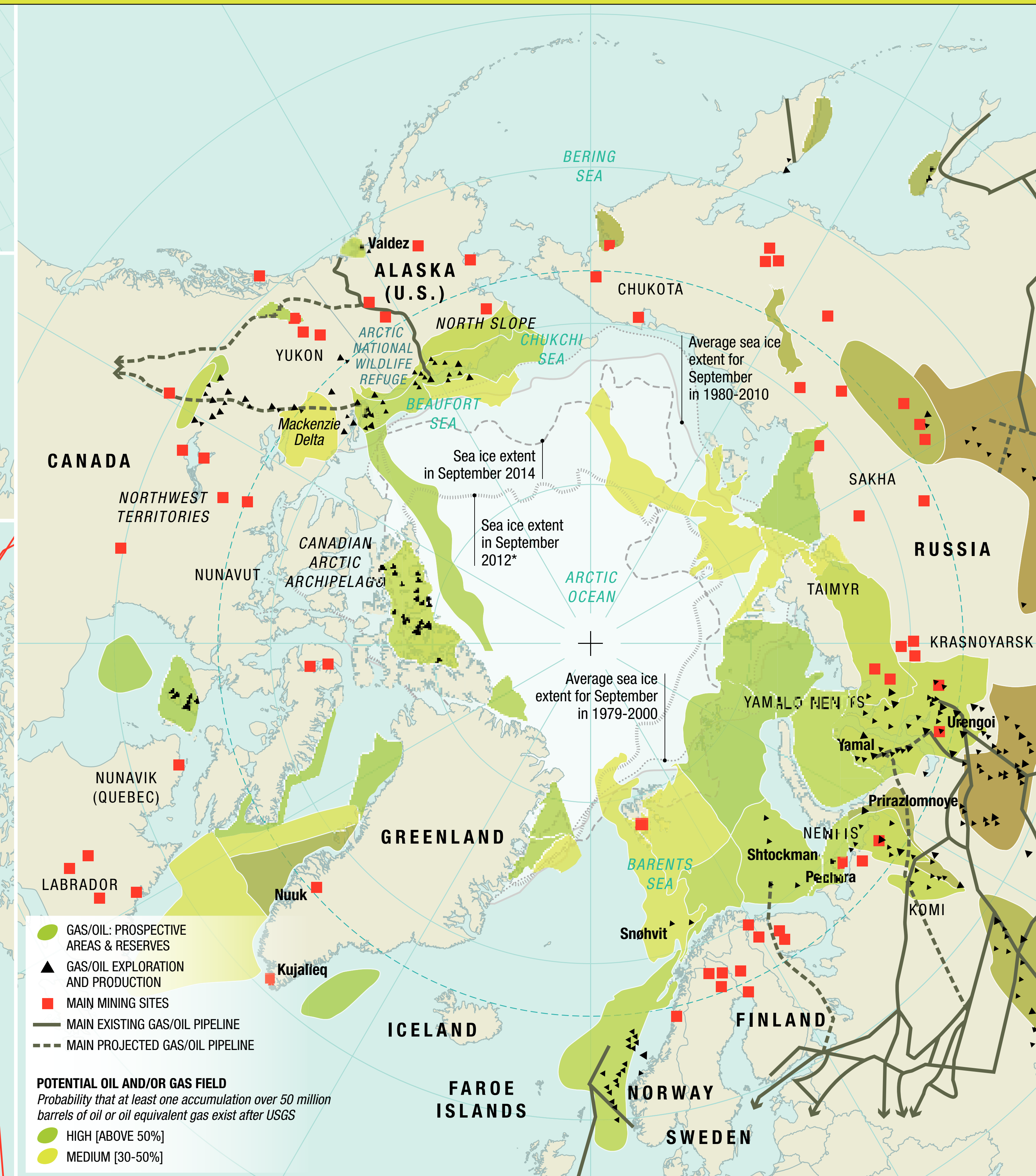
The Arctic, and especially its European part, was quickly branded as the new energy Eldorado, with the discovery of oil and gas reserves in the Barents, Pechora and Kara Seas fuelling Norwegian and Russian optimism about relocating their future energy production further north. For example, discovered in 1981, the Norwegian Snohvit—in the Barents Sea—is Europe's first and the world's northernmost gas field with a connected liquefied natural gas (LNG) facility. Coming on stream in 2007, the gas field had original reserves of 265 million standard cubic meters oil equivalent, with its LNG mainly being delivered to Europe and Asia. On the Russian side of the Barents Sea, the Shtokmanovskoye (Shtokman) gas field, which was discovered in 1988, is one of the world's largest natural gas fields, with proven reserves of 3.9 trillion cubic metres of gas. Yet the field's development is currently on hold due to its high development costs and related questions of profitability. In contrast, the Prirazlomnoye oil field, located in the Pechora Sea and discovered in 1989, →



THE VALUE OF THE DEALS
The financial value of M&A transactions from 2012 to the first half of 2017 by company type. Values are in USD billions.

Europe





Source: Nordregio

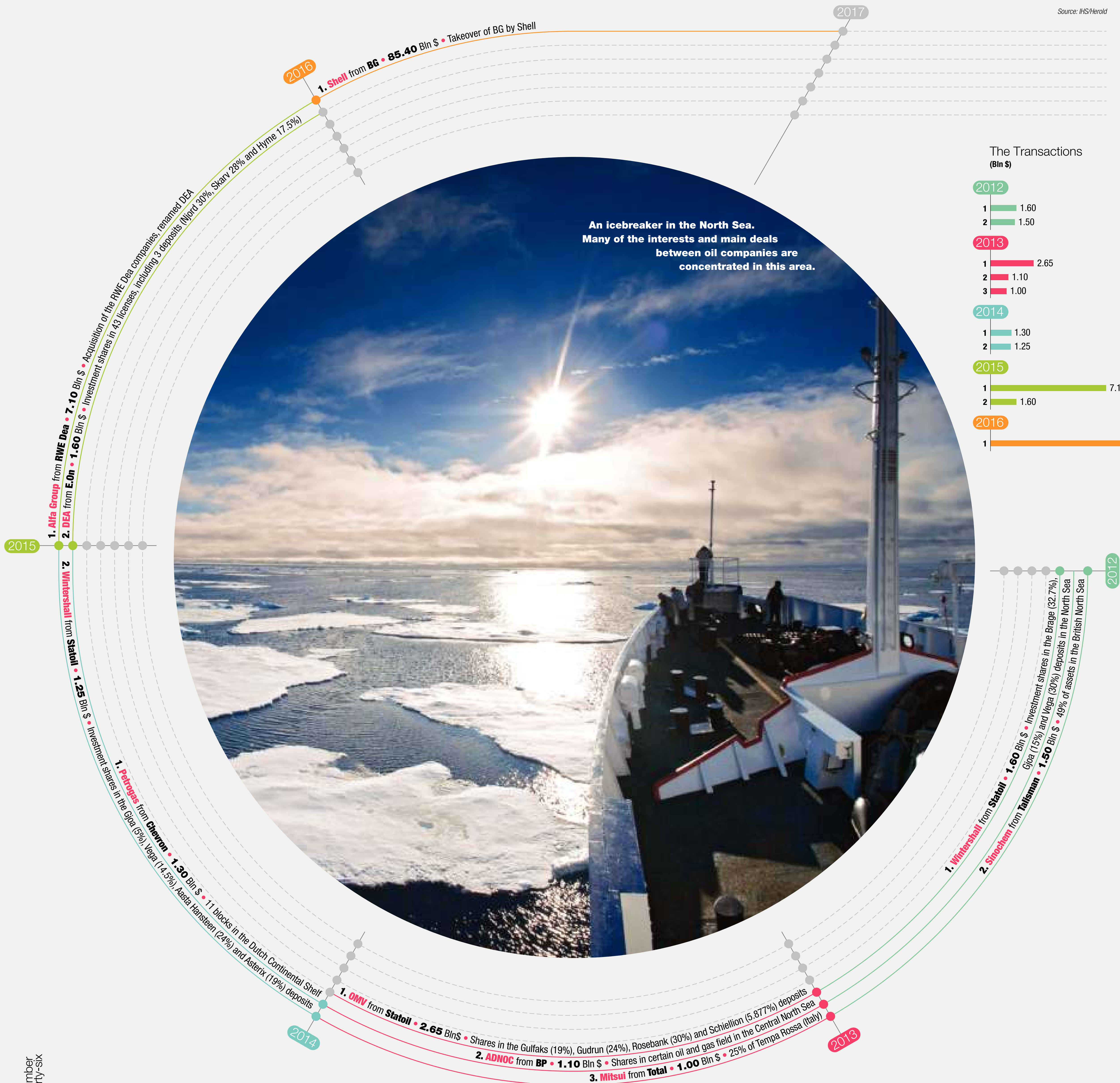
THE MAJOR RESERVES IN THE NORTH

The Arctic area has long been the subject of exploration and drilling activities for both oil and gas. In the map on the left, the European concessions are shown, with a focus (in boxes 1/2/3) relating to the distribution of Norwegian oil and gas fields. The next map shows a global view of the location of the main oil and gas fields and the infrastructure for transporting resources throughout the Arctic.

is the first offshore oil development in the Arctic. It contains over 72 million tons of oil reserves with the first consignments being dispatched in April 2014. Its oil platform now produces 10,000 tons of oil per day. Further east, the Yamal peninsula holds about 26.5 trillion cubic metres (tcm) of gas, accounting for 85 percent of Russian natural gas production, all concentrated in the broader area of the Yamal Nenets Autonomous District. Arctic oil and gas production is typically considered a long-term investment. Its viability and profitability essentially depend on two interrelated pillars: 1) the costs of retrieving the estimated resources and 2) future expectations on oil and gas prices that can be obtained on a global market that is constantly in flux. Accordingly, the European Arctic has experienced many ups and downs, high hopes and tough reality checks, over the last decade. Nevertheless, multinational oil and gas companies remain interested in the exploration and exploitation of Northern/Arctic resources. In the following sections, we explore the main acquisitions that concerned the European North in recent years. We also briefly observe the state-of-the-art in the Russian Arctic and make some considerations on the impact of Western sanctions.

The rise in Northern energy

Between 2012 and 2016, upstream mergers and acquisitions in Europe have oscillated from USD 7 billion in 2014 to a peak of over USD 85 billion in 2016. Among the key commercial operations in the European Arctic in recent years, Wintershall's growing involvement in the Norwegian Arctic and its partnership with Statoil stands out. In January 2013, Wintershall finalized its acquisition of shares from Statoil in the fields of Brage, Vega and Gjøa (Brage: 32.7 percent, Vega: 30 percent and Gjøa: 15 percent), in the Norwegian North Sea. Wintershall thus raised its production in Norway from approximately 3,000 barrels of oil equivalent (boe) to almost 40,000 boe per day. With Brage, Wintershall took over the operation of a major production platform on the Norwegian continental shelf for the first time. In return, Statoil received a 15 percent share in the development project Edvard Grieg (located west of Stavanger in the North Sea) from Wintershall and a financial compensation of USD 1.35 billion. Statoil and Wintershall deepened their partnership and agreed on a further transaction in 2014 worth USD 1.25 billion. Wintershall acquired additional shares in the two producing fields Gjøa and Vega from Statoil. Its total stake rose to 55.6 percent in Vega and 20 percent in Gjøa. Thanks to these acquisitions, Wintershall has expanded its output in Norway significantly and now produces around 60,000 boe per day. In the same deal, Wintershall took over the operatorship of Vega in March 2015. Wintershall also has a 24 percent stake in the development project Aasta Hansteen, which is led by Statoil (51 percent) and also includes OMV (15 percent) and ConocoPhillips Skandinavia (10 percent). Aasta Hansteen is located in the North Sea at approximately 300 km off the Norwegian coast, and has recoverable reserves estimated at 47 billion standard cubic metres. Drilling at Aasta Hansteen is planned to start towards the end of 2017 or the beginning of 2018. Gas will be channeled to Nyhamna in Møre and Romsdal county in Norway through the 480-km Polarled pipeline, a joint project of Statoil (37 percent), Wintershall (13.2 percent), Petoro (11.9 percent), OMV (9 percent), Shell (9 percent), TOTAL (5.1 percent), RWE Dea (4.7 percent), ConocoPhillips (4.4 percent), CapeOmega (2.8 percent) and Edison (2.3 percent). As part of the 2014 transactions, Wintershall acquired 19 percent of the Asterix discovery, where Statoil retained 51 percent ownership and operatorship. Moreover, Wintershall owns a 50 percent stake and is operator of the Maria field, located in the →

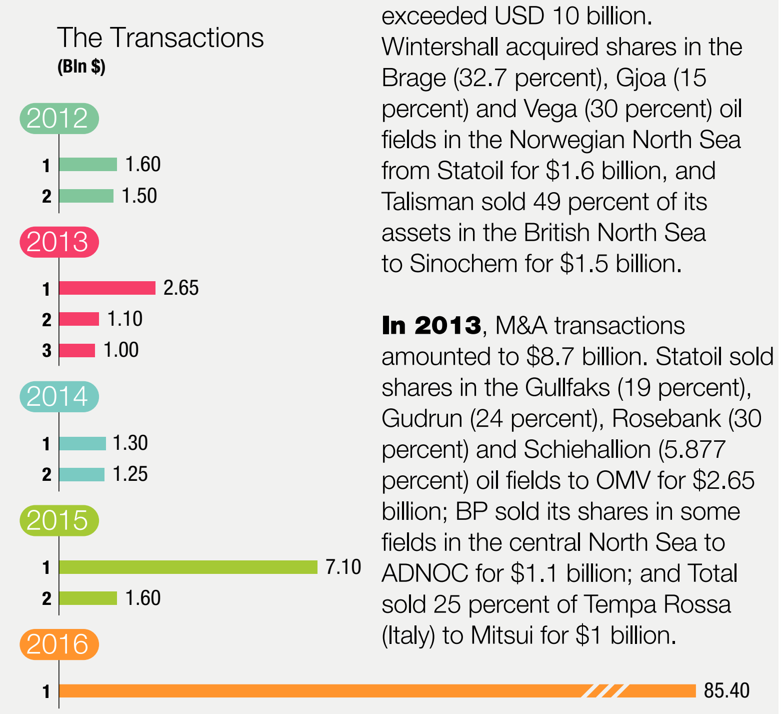


An icebreaker in the North Sea. Many of the interests and main deals between oil companies are concentrated in this area.

Source: IHS/Herold

The Main M&A

[2012/2017]



In 2012, transactions in Europe exceeded USD 10 billion. Wintershall acquired shares in the Brage (32.7 percent), Gjoa (15 percent) and Vega (30 percent) oil fields in the Norwegian North Sea from Statoil for $1.6 billion, and Talisman sold 49 percent of its assets in the British North Sea to Sinochem for $1.5 billion.

In 2013, M&A transactions amounted to $8.7 billion. Statoil sold shares in the Gullfaks (19 percent), Gudrun (24 percent), Rosebank (30 percent) and Schiehallion (5.877 percent) oil fields to OMV for $2.65 billion; BP sold its shares in some fields in the central North Sea to ADNOC for $1.1 billion; and Total sold 25 percent of Tempa Rossa (Italy) to Mitsui for $1 billion.

In 2014, acquisitions amounted to just under $7 billion. Chevron sold 11 blocks in Dutch Continental Shelf to Petrogas for $1.3 billion, Wintershall acquired shares in Gjoa (5 percent), Vega (24.5 percent), Aasta Hansteen (24 percent), Asterix (19 percent) and 4 exploration licenses in the Voring area (10 percent) from Statoil for $1.25 billion.

In 2015, transactions worth $11.6 billion were carried out. Alfa Group acquired upstream activities from RWE (RWE DEA), creating a new company named DEA, for $7.1 billion; E.On subsequently sold its shares in 43 licenses, including 3 production fields (Njord 30 percent, Skarv 28 percent and Hyme 17.5 percent) to DEA.

The largest transaction in Europe in 2016 was the takeover of BG by Shell, amounting to $85.4 billion including debt (cash and stock). With this agreement, Shell changed the focus of its portfolio to two key areas: Brazilian subsalt and the LNG market.

southern Norwegian Sea; other shareholders are Petoro (30 percent) and Centrica (20 percent). The Maria field is being developed for production in 2018 and has an estimated 180 million boe. In 2013, Statoil entered into a partnership with Austrian OMV, with the aim of freeing up cash for large investments in new discoveries. OMV acquired 19 percent of Gullfaks and 24 percent of Gudrun, two oil and gas fields in Norwegian waters. It also bought 30 percent of Rosebank and 6 percent of Schiehallion, two fields west of the Shetland Islands, as well as options for 11 exploration licences in the Faroe Islands. Statoil reduced its ownership share in Gullfaks from 70 percent to 51 percent, and from 75 percent to 51 percent in Gudrun, but retained its operatorship on both fields. For these acquisitions, OMV paid Statoil USD 2.65 billion, making it the largest deal in the Austrian oil company's history. The deal also increased OMV's reserve base by nearly a fifth and boosted its production by about 13 percent.

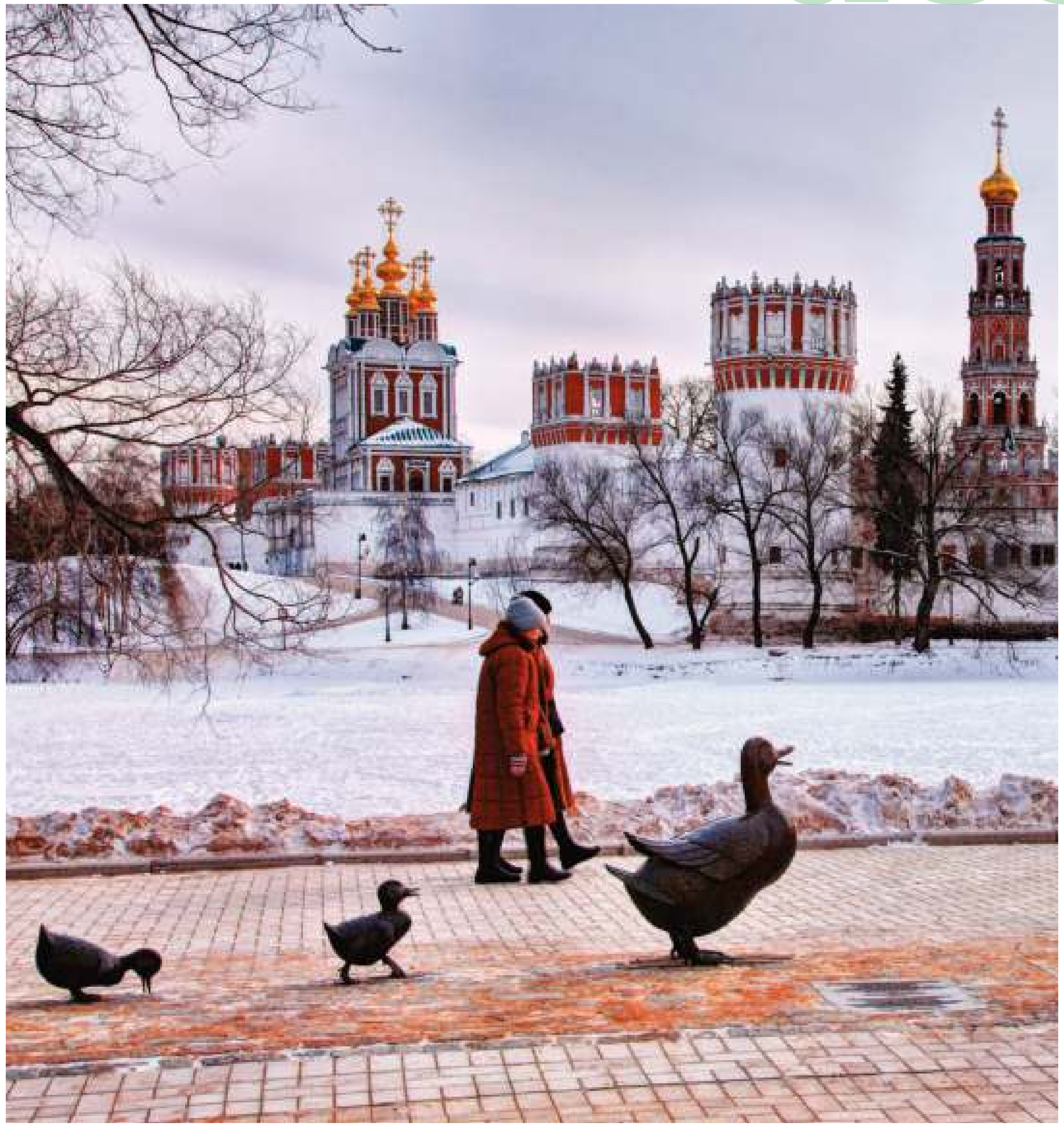
The Dragon's Arctic interest

In 2012 and 2013, two Chinese companies made their first acquisitions in the United Kingdom's offshore fields. In July 2012, Sinopec acquired a 49 percent share in the Talisman Energy's North Sea assets through its subsidiary Addax Petroleum UK. The joint venture deal was valued at USD 1.5 billion. The deal transferred to Sinopec nearly 16,000 barrels of oil per day and gave it experience operating offshore. Moreover, in 2013 the Chinese CNOOC acquired the Canadian Nexen for USD15.1 billion, China's largest takeover of an oil and gas company. CNOOC thus gained control of the Buzzard oil field, the United Kingdom's largest oilfield. Through Nexen, the company also acquired 36.5 percent of the Golden Eagle project, 70 km northeast of Aberdeen, Scotland. According to CNOOC, the deal increased the company's production and reserve base by 20 percent and 30 percent, respectively. Also in 2013, Abu Dhabi national energy company Taqa purchased stakes in three fields in UK North Sea waters, corresponding to roughly 21,000 boe per day of production, for USD 1.058 billion.. Also worthy of notice in terms of growing Asian investments in the European upstream, in March 2013, Total sold to the Japanese Mitsui a 25 percent interest in the Tempa Rossa field, located in the Basilicata region of southern Italy, while retaining a 50 percent share and operatorship (Shell holds the remaining 25 percent). Commercial operations also took place in the Dutch North Sea. In 2014, Chevron sold its interests in 11 offshore blocks on the Dutch Continental Shelf to Oman-based Petrogas. In 2013, the blocks had an average net daily production of approximately 2,000 barrels of crude oil and 41 million cubic feet of natural gas.

The major BG Group-Royal Dutch Shell gamble

The most significant commercial operation of 2015 in the region was RWE's sale of its oil and gas production unit RWE Dea to LetterOne Group, the investment business set up by the Russian Alfa Group conglomerate, for approximately USD 7 billion. The deal led to the creation of DEA. Subsequently, DEA bought from E.ON equity interests in 43 licences including the shares of the three producing fields Skarv (28.1 percent), Njord (30 percent) and Hyme (17.5 percent) in the Norwegian North Sea, thus bringing DEA's production there to about 75,000 boe per day. In 2016, Royal Dutch Shell's acquisition of the BG Group, a Britain-based oil and gas producer, was the largest deal, worth approximately USD 50 billion. The acquisition allowed Shell to become the world leader among listed companies in liquefied natural gas, a field in which BG was a key player. It also enabled Shell to acquire a leading position in Brazilian offshore waters, thereby complementing the company's experience in deepwater oil and gas field in the Gulf of Mexico and Nigeria. The deal was also the largest energy merger since the substantial drop in the oil price beginning in late 2014. The drop in the oil price - and Western sanctions - have not halted investment and production in the Russian Arctic either. Although several oil multinationals, including Exxon Mobil, were forced to halt activities in the region (such as exploration in the Kara Sea), crude oil production in the Russian Arctic is expected to grow by 10 percent in 2017 compared to the previous year. The increase is partly due to the growing capacity at the ice-resistant Prirazlomnaya offshore oil platform, the only one of its kind in the world. In 2016, Arctic oil production accounted for 16.8 percent of all Russian oil production, with an expected slight rise in 2017. On the other hand, Arctic gas activity from the Yamal peninsula accounts—as already indicated—accounted for more than 85 percent of total Russian gas production. Investments in the Yamal LNG facility (launched in 2013, with ownership as follows: 50.1 percent Novatek, 20 percent each for Total and CNPC and 9.9 percent for China's Silk Road Fund) and the export of gas-employing ice-capable LNG carriers via the Northern Sea Route will strengthen Russia's position in the global gas markets.

Russia&Caspian

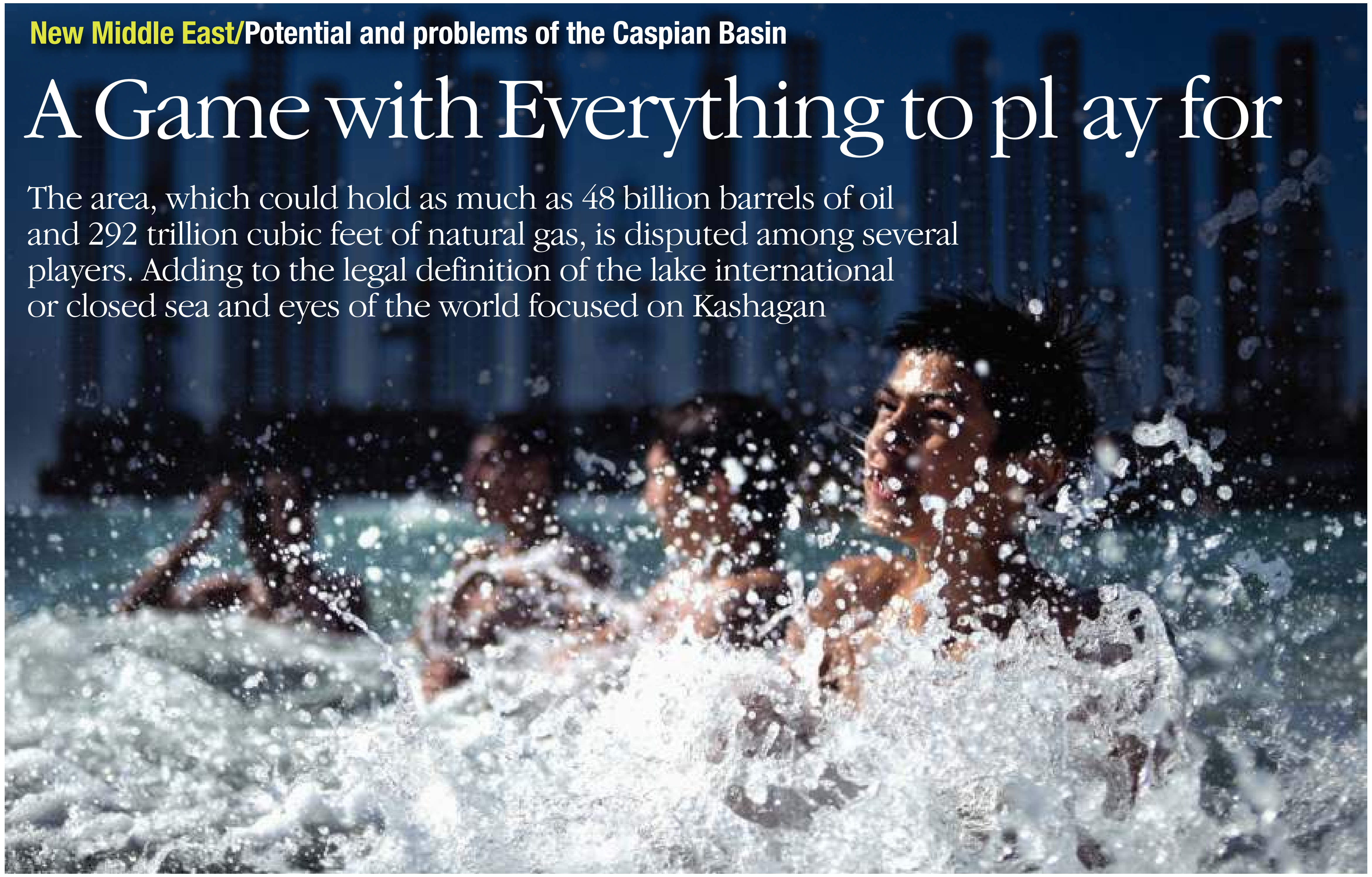


#deals

New Middle East/Potential and problems of the Caspian Basin

A Game with Everything to pl ay for

The area, which could hold as much as 48 billion barrels of oil and 292 trillion cubic feet of natural gas, is disputed among several players. Adding to the legal definition of the lake international or closed sea and eyes of the world focused on Kashagan



LELLO STELLETTI

For more than five years he worked for *Agenzia Nova*, where he deals with energy, defense and Eastern Europe. On these topics he also focused his university studies.

A year ago, in October 2016, the first shipment of crude oil left the Kashagan offshore field in Kazakhstan, the result of a titanic project lasting over twenty years and an investment of just under USD 60 billion.

The history of Kashagan, an offshore oil field in the north-eastern Caspian Sea, just off the coast of Kazakhstan and 80 km south of the city of Atyrau, exemplifies the difficulties encountered operating in a region with huge interweaving economic interests, geopolitical problems and virtually insurmountable environmental difficulties. Eni, under Guglielmo Moscato, was the first company to open the way to Kazakhstan in the 1990s with the enormous Karachaganak onshore field, an opening that allowed western companies to pursue their interests in the former Soviet Republic. A consortium headed by Agip and then Mobil, Total, Shell, and BG Group, reached an agreement with the government of President Nursultan Nazarbayev, who is still in office, to prospect in a country which was striving to emerge from the shadow of the former U.S.S.R. This involved working in a virtually unknown region, in a physical and economic environment which had experienced very little contact with the West, apart from the now remote legacy of the Dutch East India Company.

The explorations lasted many years and used seismic waves of unprecedented power to determine the contours of the geological structure. In 2000, the explorations revealed that under a saline dome, at a depth of 4.5 km below the bed of the Caspian Sea, there were crude oil deposits estimated at 35 billion barrels, 13 billion of which were recoverable. It was an immense asset, but an equally great technological challenge, which ranged from the pressure (which creates serious extraction difficulties) to very high sulfur content and prohibitive weather conditions that include blisteringly hot summers and waters that freeze from October to March. Furthermore, the shallow seawater prevented the use of standard perforating vessels, and wells had to be built on artificial islands created by transporting 11 million cubic meters of rock. This delayed the work but also significantly increased costs, creating obvious difficulties in relations with the Astana government. The international consortium structure changed several times due to the growing costs of the enterprise and the complex relationships with the Nazarbayev government. In 2001, Eni was appointed as an exclusive operator because—so the story goes—the Kazakhs didn't trust the Americans, the British, or the French. After years of delays and various ownership issues, oil production began on September 11, 2013 with plans to produce 8 million tons of crude oil by 2014. The plan was short-lived, however, because the presence of sulphuric acid in the flow turned out to be highly corrosive, causing the pipes to split. Production had to be suspended to replace the pipework. Further expenses and delays followed until, in mid-October 2016, a press release from Eni announced the start of export operations: “Production, which has restarted following completion of the pipeline replacement work, will increase gradually to an initial 180,000 barrels a day, with a target of 370,000 barrels a day by the end of next year.” Eni stated that “considering the size and technical, environmental and logistical features, Kashagan is one of the most complex and challenging projects ever undertaken in the whole world.” The Kashagan project partners are China National Petroleum Corp (8.33 percent, acquired in 2013 for USD 5 billion from ConocoPhillips, through KazMunaiGaz), Impex (7.56 percent) and with a share of 16.81 percent, Shell, Exxon Mobil, Total, KazMunaiGaz, and Eni. Each company has been given responsibility for part of the work. Eni has been entrusted with the so-called "first oil phase,” which is the current stage.

The Caspian Sea challenge

The story of the Kashagan field exemplifies the difficulties of operating in the Caspian Sea region, which has been a focus of the energy strategy of the major international players since the beginning of the 1990s, when it was referred to as the “New Middle East.” However, due to a variety of issues, foremost among them the status of the Caspian (lake or sea? The issue is not only geographical, because there are different international treaties at play), competition between the coastal states and climatic and environmental conditions, it hasn't always lived up to expectations. In 2003, the U.S. Energy Information Administration (EIA) estimated that the basin area could hold up to 48 billion barrels of oil and 292 trillion cubic feet of proved and probable gas reserves. In comparison, the picture for the Middle East area is considerably different, with reserves of over 803 billion barrels of oil and about 2,827 trillion cubic meters of natural gas. This estimate includes Iranian reserves and shows that, while certainly significant, the resources of the Caspian could hardly pose a threat to those of Persian Gulf countries. Regardless of comparisons, the Caspian Basin remains an interesting region, not just for companies operating in the hydrocarbon sector but also for a series of state and transnational actors. The U.S. has long been watching developments in the area and was one of the first countries to set its sights on it, with companies like Chevron and ExxonMobil. The E.U., for its part, has long been seeking to diversify its energy supplies in order to reduce its dependence on Russian gas. Turkey, too, has been closely monitoring developments in the area and can rely on the good relations it has built with the two coastal states of Azerbaijan and Turkmenistan. The Caspian Sea area has also become a focus of interest for Asian countries such as China, India and Japan, all of which (albeit for different reasons) are looking for new sources of gas and oil supplies. The Caspian Sea area is a hub of constantly developing gas exploration and extraction projects. The natural gas sector in particular could enable the region to increase global production by 27 percent over the next ten years. Turkmenistan has proven natural gas reserves of 17.5 trillion cubic meters, and, according to the EIA, has the greatest potential to contribute to production growth in the sector in the years ahead. Turkmenistan's increased production will be primarily sustained by the coming into operation of new exploitation phases of the vast Galkynysh field (in the northeast of the country), the second largest in the world after South Pars in the Gulf, with reserves estimated by Turkmenistan's authorities at 27.4 trillion cubic meters. The recent discovery of a new field in Chelekbay is also significant and fully confirms the country's abundance of natural resources and growth potential. This new field, situated near Galkynysh, whose discovery was announced by the authorities in Ashgabat last December, is thought to have an extraction potential of around one million cubic meters per day.

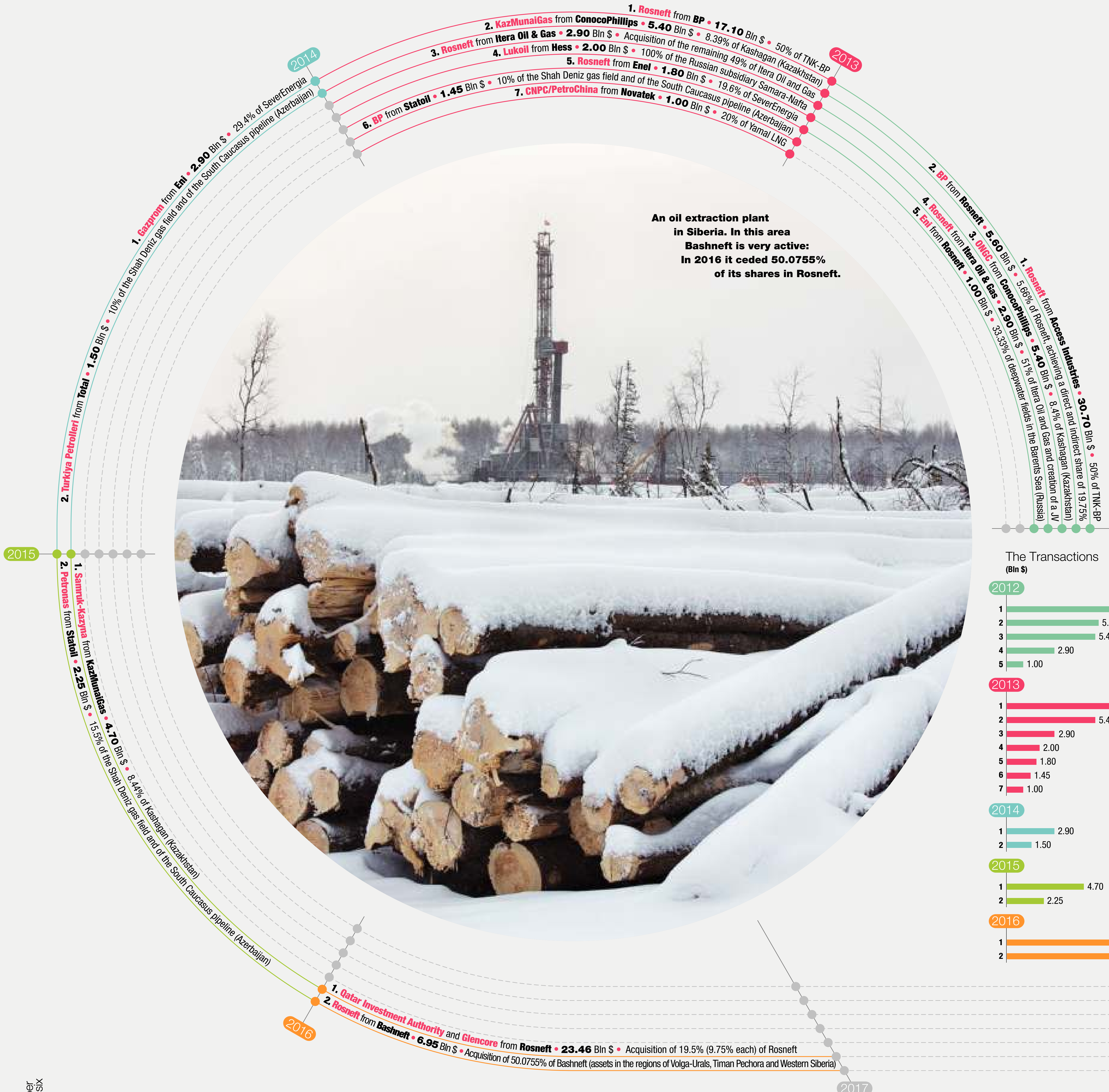
Potential markets for this wealth

Buyers will have to be found for all this gas, and China is at the top of the list, having played a major role in fostering increased production by providing capital investment, technology and transport infrastructure. This relationship, however, has turned Turkmenistan into a debtor nation vis-à-vis China to the tune of billions of dollars, and has turned out to be a double-edged sword. The so-called “Line D,” the fourth section of Central Asia-China Gas Pipeline (CACGP), which already delivers 72 percent of Turkmenistan's gas exports, was expected to take ten years to complete. With the project's completion, CACGP could reach an annual delivery capacity of 85 billion cubic meters of gas, a considerable increase compared to the current 55 billion. But there have been many challenges along the way, and construction work on Line D was suspended indefinitely last March. The new line was due to run through Uzbekistan, Tajikistan, and Kyrgyzstan, and reach north-western China. The countries along the pipeline path would not have benefited from Turkmen gas itself but would have gained revenues by charging transit fees. The project's suspension, albeit temporary, puts a strain on Turkmenistan's struggling economy, which is mostly based on exports of gas whose price has fallen sharply in the last three years. In addition to its debt with China, as yet the only buyer of Turkmenistan's gas, there are also problems with Russia, one the leading actors in the Caspian Basin. In early 2016, Moscow canceled its supply contract with Turkmenistan due to the failure to reach a price agreement. With Ashgabat demanding USD 240 per one thousand cubic meters of gas, Gazprom negotiated two new deals with gas rich Uzbekistan and Kazakhstan at the price of USD 140 per one thousand cubic meters. To make matters worse, Turkmenistan lost its deal with Iran early this year when the latter decided to invest in internal electricity production.

In order to diversify its sources of revenue, Turkmenistan is focusing on two alternatives: India, via Afghanistan, and the European Union via the Caspian Sea and Azerbaijan. While these prospects are appealing, they are also highly complicated. First, Ashgabat needs to attract investments for its infrastructure, which has to be built from scratch. The first option, due to the unstable and uncertain Afghan theater, makes India seem more distant than it is from a purely geographical perspective. The second option is bedeviled by the persisting problem of the status of the Caspian Sea and, without a solution to this question, Russia will never agree to the construction of a trans-Caspian gas pipeline that would become a serious competitor for its supplies to Europe.

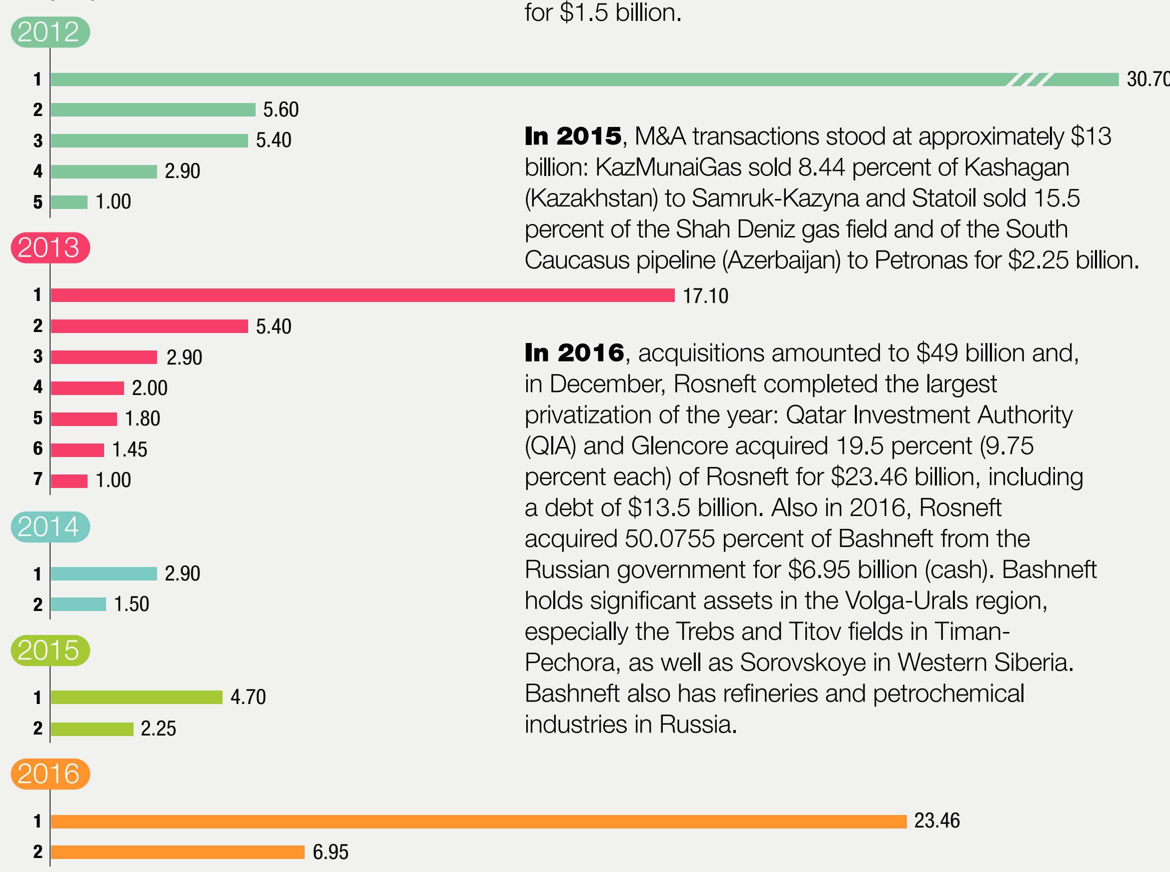
The decisive role of Russia

Russia's soft power in the area, thus far, remains very strong and hinders Turkmenistan's great potential. Russia is currently very interested in developing its continental resources in order to expand its gas and oil extraction potential. In recent years, as one of the world's largest hydrocarbon exporters, Russia has begun to seek a viable alternative to its western Siberian fields, whose production levels are gradually and inevitably declining. This alternative is the Caspian Sea, bordered by the Russian region of Astrakhan, famous for its hydrocarbon deposits consisting of natural gas and condensate as well as oil. Its onshore resources amount to almost 6 trillion cubic meters of gas and over one billion tons of liquid hydrocarbons. Unlike Azerbaijan, Kazakhstan, and Turkmenistan, Russia decided to begin development of its offshore oil and gas fields in the Caspian Sea quite late in the day. During the Soviet era, the northern and central areas of the Caspian Basin, over which Russia has exclusive sovereignty and hydrocarbon exploration rights, were not deemed very promising. The emergence of the Astrakhan region as a “land of conquest” for Russia's energy players is therefore fairly recent. LUKOIL did not start its exploration program in the northern portion of the Sea until 1994, and for many years it was the only large company operating in what was regarded as a low profit area. Never-→



An oil extraction plant in Siberia. In this area Bashneft is very active: In 2016 it ceded 50.0755% of its shares in Rosneft.

The Transactions
(Bln $)



Source: IHS/Herold

The Main M&A

[2012/2017]

In 2012, transactions amounted to approximately USD 55 billion: Rosneft acquired 50 percent of TNK-BP from Access Industries for $30.7 billion; BP bought 5.66 percent of Rosneft for $5.6 billion, increasing its stake (direct and indirect) in the Russian company to 19.75 percent; ConocoPhillips sold 8.4 percent of Kashagan (Kazakhstan) to ONGC (Indian state-owned company) for $5.4 billion; Rosneft acquired 51 percent of Itera Oil and Gas for $2.9 billion and Eni acquired 33.33 percent of deep-water fields in the Barents Sea (Russia) from Rosneft for $1 billion.

In 2013, M&A transactions amounted to approximately $35 billion: Rosneft concluded its TNK-BP transaction by acquiring 50 percent of BP for $17.1 billion; ConocoPhillips sold 8.39 percent of Kashagan (Kazakhstan) to KazMunaiGas for $5.4 billion; Rosneft then acquired the remaining 49 percent of Itera Oil and Gas for $2.9 billion. Lukoil acquired the Russian subsidiary Samara-Nafta from Hess for $2 billion and Enel sold 19.6 percent of SeverEnergia to Rosneft for $1.8 billion. Statoil sold 10 percent of the Shah Deniz gas field and of the South Caucasus pipeline (Azerbaijan) to BP for $1.45 billion and Novatek sold 20 percent of Yamal LNG to CNPC/PetroChina for $1 billion.

In 2014, acquisitions totaled approximately $10 billion: Eni sold 29.4 percent of SeverEnergia to Gazprom for $2.9 billion and Total sold 10 percent of the Shah Deniz gas field and of the South Caucasus pipeline (Azerbaijan) to Turkiye Petrolleri for $1.5 billion.

In 2015, M&A transactions stood at approximately $13 billion: KazMunaiGas sold 8.44 percent of Kashagan (Kazakhstan) to Samruk-Kazyna and Statoil sold 15.5 percent of the Shah Deniz gas field and of the South Caucasus pipeline (Azerbaijan) to Petronas for $2.25 billion.

In 2016, acquisitions amounted to $49 billion and, in December, Rosneft completed the largest privatization of the year: Qatar Investment Authority (QIA) and Glencore acquired 19.5 percent (9.75 percent each) of Rosneft for $23.46 billion, including a debt of $13.5 billion. Also in 2016, Rosneft acquired 50.0755 percent of Bashneft from the Russian government for $6.95 billion (cash). Bashneft holds significant assets in the Volga-Urals region, especially the Trebs and Titov fields in Timan-Pechora, as well as Sorovskoye in Western Siberia. Bashneft also has refineries and petrochemical industries in Russia.

theless, by as early as 2000 Russia's exploration activities started to score its first successes. That year, LUKOIL announced the discovery of the Yuri Korchagin field, followed by seven more over the next eight years: Rakushechnoye and 170 Kilometer in 2001, Khvalynskoye and Sarmatskoye in 2002, Vladimir Filanovsky in 2005, and Morskoye and Tsentralnoye in 2008. The reserves are estimated to contain a total of 4.7 billion barrels of oil equivalent. The first to be discovered, Yuri Korchagin, has proven reserves amounting to around 29 million barrels of oil and almost 64 billion cubic meters of natural gas. So far, according to its own calculations, the Russian company LUKOIL has invested 45 billion rubles (equivalent to EUR 640 million at the current exchange rate) in this field, underscoring the importance being attributed to it. The Vladimir Filanovsky field is the largest oil reserve discovered in Russia in the last 20-25 years, with estimated reserves of 290 million barrels of oil equivalent. A few months ago, it was announced that a fifth well had been put into operation. LUKOIL operated on its own in the area for many years, while Gazprom and Rosneft arrived on the scene at a later stage. The former joined LUKOIL in the development of the Tsentralnoye fields, while Rosneft bought the Lagansky drilling block in 2013 and, a year later, began the joint construction of a drilling platform in Rybachya with LUKOIL. The last field was discovered in Velikoye in 2013. Estimates of the latter's reserves are still underway but according to preliminary data it could contain up to 300 million tons of oil and 90 billion cubic meters of gas.

Despite these encouraging figures, there are several challenges facing the Russian economy. Although it has come out of recession this year, it is still fragile and beset by the international sanctions imposed on Russia following its annexation of Crimea. A major challenge has to do with climate. The northern areas of the Caspian freeze over in winter and share the typical desert conditions of the Central Asian steppes in summer. These extreme temperature changes have negative impacts on exploration and drilling activities. Added to this is the region's relative shortage of special equipment and qualified personnel to construct and manage offshore facilities - a significant factor in holding back investment by new companies in the Caspian and one of the reasons why LUKOIL is still the leading company operating in the region.

Developments in Kazakhstan

Russian companies have thus decided to open their doors to another state→

Russia & Caspian

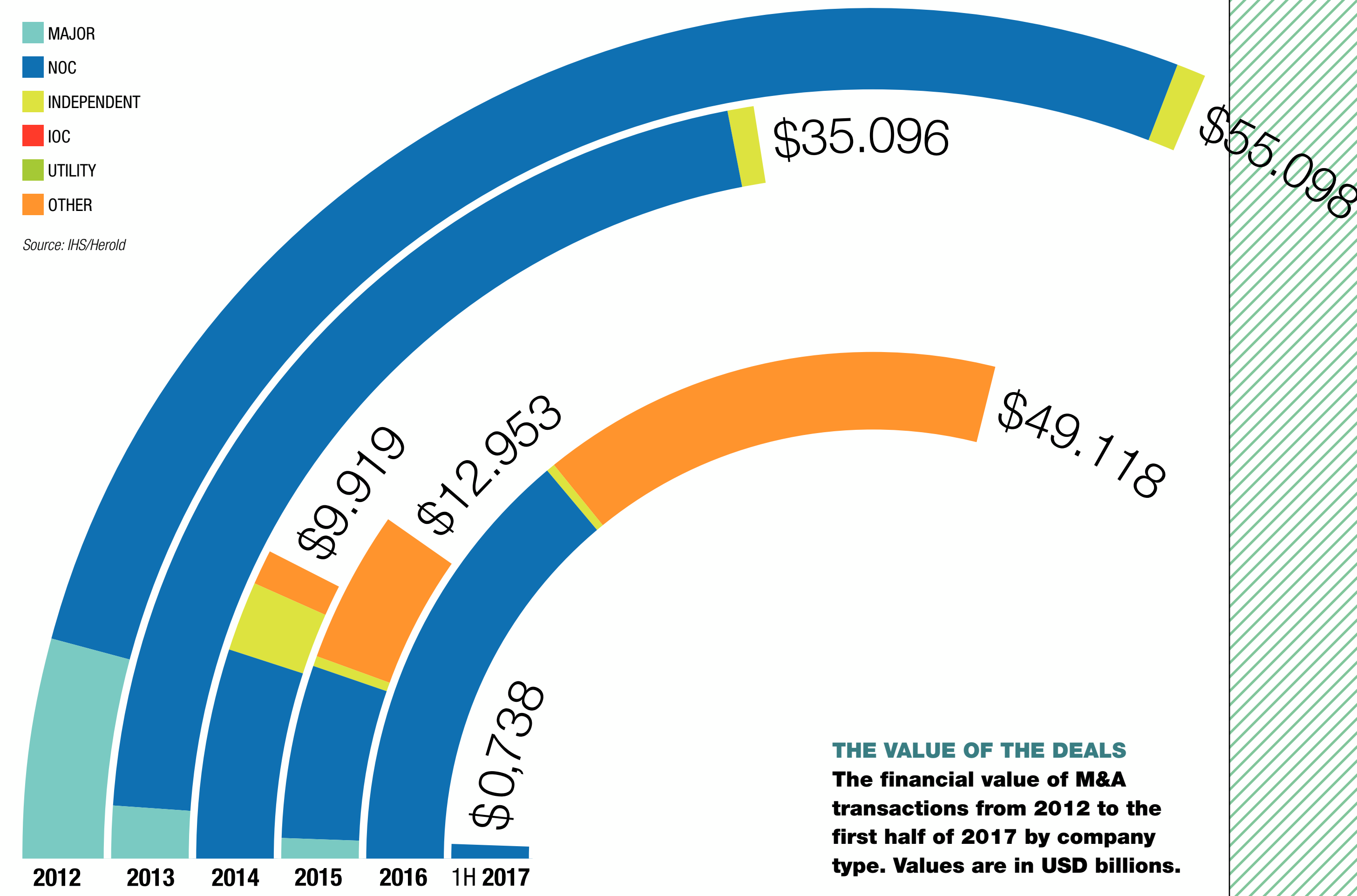
THE TREASURE OF THE BASIN

On this map you can see the oil and gas fields in the area, in particular the "treasure" of Kashagan. You can also see the main pipelines, including the CPC and the Uzen-Atyrau-Samara pipeline, mentioned in the article.

actor in the region: Kazakhstan. Moscow and Astana have a solid relationship and Kazakhstan is undoubtedly Russia's main ally in Central Asia. In late 2016, the Russian government authorized the establishment of the Central Oil and Gas Company, a joint venture between LUKOIL and Gazprom (both with a 25 percent share) and the Kazakh company KazMunaiGaz (with 50 percent). The company is engaged in developing the Tsentralnoye field situated in the Russian sector of the Caspian Sea. Cooperation between Russia and Kazakhstan goes back to October 15, 2015, when the two countries signed a memorandum of understanding that includes the rights to exploitation of the Caspian seabed. Kazakhstan, moreover, participates in the exploitation of the offshore field of Khvalynskoye, also operated by LUKOIL, whose current reserves amount to some 322 billion cubic meters of gas, 18.4 million tons of condensate, and 242 million tons of oil. Kazakhstan is also acting independently, however, participating in development projects in the Caspian Sea without Russia. In October 2016, despite the many difficulties described at the beginning, production was resumed at the giant Kashagan oil and gas field, which many define as a "great challenge" but which, once the obstacles have been overcome, could become one of the main driving forces for development in Kazakhstan. In recent years, the country has been described as a "launch pad," but its rise has been hamstrung by its geographical position, controversial political situation, and strong ties with Russia.

Kashagan, however, is not the only field in Kazakhstan; there are also long-running and well-established operations such as the Tengiz field. It was discovered in 1979 near the northeastern shore of the Caspian Sea and was immediately deemed one of the greatest hydrocarbon discoveries in recent history. Attracted by its prospects and taking advantage of the dissolution of the Soviet Union, several companies decided to invest in the field. Since 1993, Tengiz has been operated by the Tengizchevroil consortium, which has a 40-year right to the field. The consortium's partners are Chevron (50 percent), Exxon Mobil (25 percent), Kazakhstan Petroleum (20 percent), and LUKOIL (5 percent). Today, Tengiz accounts for 45 percent of the country's overall oil production. Another giant field for oil, condensate and natural gas production is Karachaganak, situated in western Kazakhstan, in the so-called Pre-Caspian Basin. Its estimated production is approximately 230 thousand barrels of oil and 26 million cubic meters of natural gas per day. It is operated by the Karachaganak Petroleum Operating consortium, with Eni and Shell as joint operators, each holding a 29.25 stake. The other partners in the consortium are Chevron (18 percent), LUKOIL (13.5 percent), and KazmunaiGaz (10 percent). 51 percent of production is delivered to the Orenburg facility in Russia, and the rest is exported to Western markets through the Caspian Pipeline Consortium and the Atyrau-Samara pipeline, which is directly connected to Russia's export network. The Caspian Pipeline Consortium is one of the leading examples of collaboration between Russia and Kazakhstan, as well as the many other international players involved, and enables the oil produced in the Kazakh fields to be exported to the Western partners. Among these fields is Tengiz, which has been directly connected to Russia's Black Sea port of Novorossiysk through a pipeline that opened in 2001. Western countries, however, are not the only recipients of Kazakhstan's hydrocarbon production. Large-scale Chinese companies, just as they did in Turkmenistan, also set their sights on the country's main energy production projects. Thus, in 2013, CNPC acquired 8.4 percent of the Kashagan consortium, paying more than USD 5 billion to KazMunaiGaz. Also, in early 2016, the China Energy Company Limited bought a 51 percent stake of KMG International— the international branch of KazMunaiGaz—while the China Investment Corp holds an 11 percent share of KazMunaiGas Exploration Production, another subsidiary of the Kazakh state-owned company. A demonstration of the strengthening axis of energy between Astana and Beijing is the development of the Kazakhstan-China gas pipeline, which, by the end of 2017, once the six compression stations have been completed, will carry 25 billion cubic meters of gas a year.

It is worth remembering that in economic terms during its 25 years of independence, Kazakhstan has developed its energy and mining sectors above all others. The country is the world's biggest uranium producer, tenth coal producer, 18th oil producer and has the 14th biggest gas reserves. There is also a variety of primary energy sector infrastructure, including the Kazakhstan-China oil pipeline, which allows Astana to export oil directly from its fields in the Caspian Sea area; the Central Asian gas pipeline system, which dates from the Soviet era and is currently controlled by Russian company Gazprom, transporting gas extracted from fields in Turkmenistan, through Uzbekistan and Kazakhstan, to Russia; the Central Asia-China gas pipeline system, created in 2009 and currently being extended, carrying Turkmen gas to the Chinese region of Xinjiang through Uzbekistan and Kazakhstan.



THE VALUE OF THE DEALS

The financial value of M&A transactions from 2012 to the first half of 2017 by company type. Values are in USD billions.

External and internal challenges

This overview of the hydrocarbon reserves of three of the leading actors along the rim of the Caspian Basin shows not only the vastness of the reserves but also the great challenges involved, particularly in terms of the very high costs to investors. The fall in oil and gas prices in recent years has forced investors to maintain a fairly strict discipline with regards to capital distribution. It has also caused considerable problems to the economies of the Caspian countries due to their heavy dependence on hydrocarbon exports. Sanctions against Russia and Iran have certainly not helped matters, given the high level of interdependence between the various coastal states. This is one of the reasons why countries such as Azerbaijan, Kazakhstan, and Russia have chosen to adhere to the oil production cuts proposed by OPEC producers last year, in the hope of fostering an increase in oil prices. The problem is exacerbated by the fact that, thanks to the so-called shale gas revolution, the U.S.—one of the actors with the keenest interest in the vast Caspian Sea hydrocarbon reserves—is close to achieving the energy self-sufficiency it has so eagerly pursued. Exports to China are not sufficient to offset the shift in perspective of some of the main energy importers. Beijing's energy demand remains high, but new transport infrastructure will need to be built in order to meet it.

However, Azerbaijan is counting on collaboration with the E.U. The European Union, which is always on the lookout for new sources to reduce its dependence on Russian gas, is keeping a close eye on discoveries in the Eastern Mediterranean, but has in the meantime turned to Azerbaijan and the Southern Gas Corridor. The development of the Azeri Shah Deniz field, situated in the southern Caspian, around 70 km south-east of the capital Baku, at a depth of 600 meters, is crucial in this respect. Discovered in 1999, it holds estimated reserves of between 50 and 100 billion cubic meters of gas. It is managed by BP, which owns a 28.8 percent stake. Other partners include TPAO (19 percent), SOCAR (16.7 percent), PETRONAS (15.5 percent), LUKOIL (10 percent) and NIOC (10 percent). In June 2013, the ShahDeniz II consortium for transporting gas to Europe chose the Trans-Adriatic Pipeline (TAP) project over the Nabucco-West pipeline. In September of the same year, Enel, Hera, Shell, E.On, Gas Natural Fenosa, Gdf Suez, Axpo, Bulgargaz and Depa signed gas supply contracts in Baku for an estimated EUR 130 billion. The 870 km pipeline will run from Greece, close to the border with Turkey, through Albania, and under the Adriatic seabed for 104 km, coming ashore in the province Lecce, in the Italian Apulia region. The initial transport capacity is expected to be around 10 billion cubic meters of natural gas a year, which could be doubled to 20 by adding a third compression station to the two already planned. The E.U. has assigned TAP the title of Project of Interest because of its crucial role in opening up the Southern Gas Corridor, one of the 12 priority energy corridors needed to achieve European objectives in the sector. In April 2015, TAP awarded Saipem the engineering, supply, construction and installation contract for the offshore section of the project. External factors are compounded by internal challenges, including Russia's soft power, competition between the various state actors in the area, and the legal status of the Caspian Sea. The long arm of Moscow, for instance, has been the cause of many of the problems currently facing Turkmenistan, seen by Moscow as a dangerous competitor for Russian supplies. Russia is likewise the main stumbling block in reaching agreement on a Caspian Sea convention. The dissolution of the Soviet Union opened the way for the initial claims regarding the status of the Caspian Sea. The issue concerns whether the Caspian should be legally defined as an international lake or an enclosed sea. If it were declared a sea (enclosed, but nevertheless a sea), the 1982 Treaty of Montego Bay would apply. Accordingly, the coastal states would have jurisdiction within 12 nautical miles, but beyond this they would be able to exploit an exclusive economic zone extending up to 200 miles from the baseline. If in legal terms the Caspian were a sea, the principle of the so-called "median line" would apply whereby sea borders are determined by a line every point of which is located at an equal distance of 12-nautical miles from the coastlines. In this case, the Caspian Sea would be subdivided into sectors resulting in the allocation of 30 percent of the total area to Kazakhstan, 20.6 percent to Azerbaijan, 19.2 percent to Turkmenistan, 15.6 percent to Russia, and 14.6 percent to Iran. If, however, the Caspian were legally defined as a lake, the coastal states would only be able to exercise their exclusive territorial rights within 12 miles of their baselines, while beyond that there would be joint exploitation and an international authority would be appointed to coordinate the extraction and division of seabed resources.

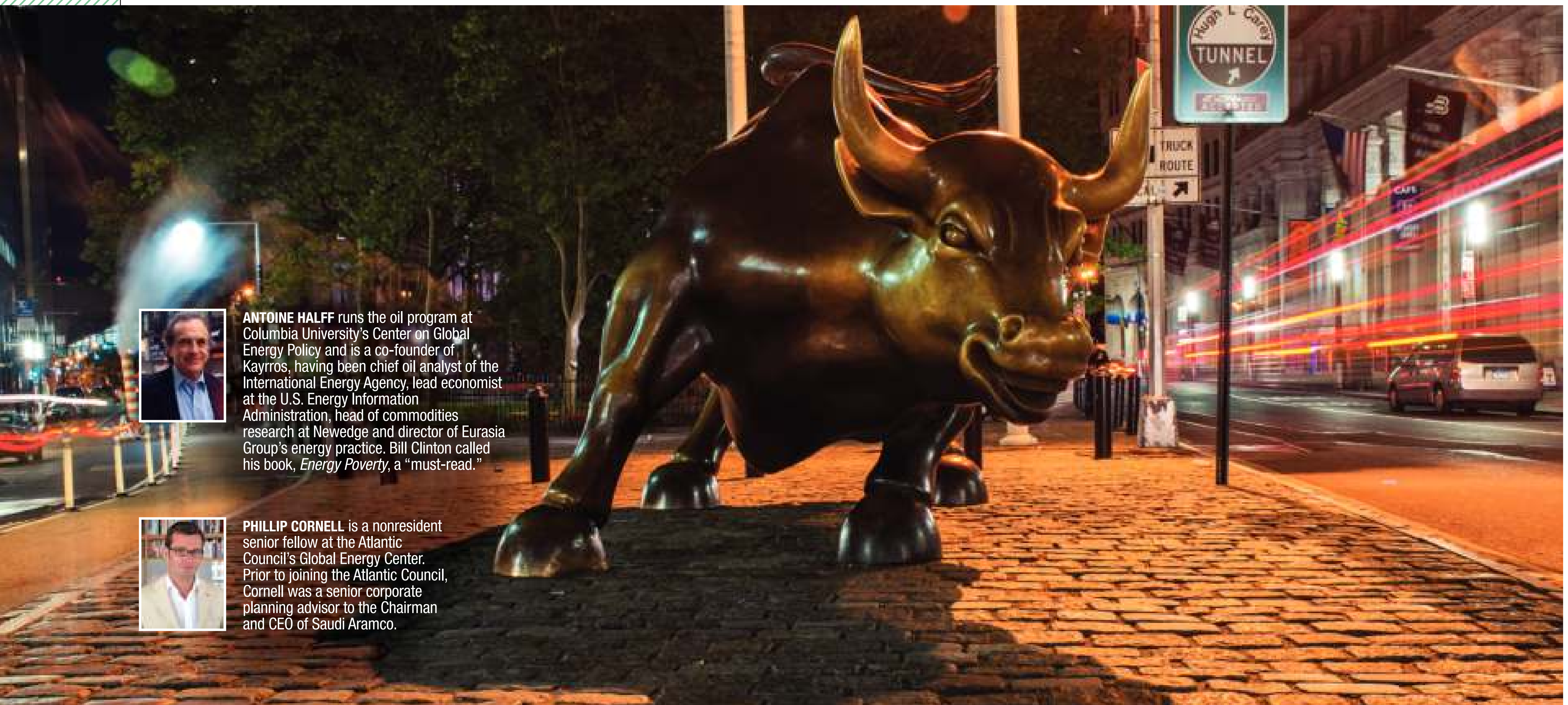
This issue reveals how each coastal state has its own individual needs, interests and priorities, which often clash with those of its neighbors. Iran, for instance, has a low level of oil and gas production in the Caspian, whereas Azerbaijan is totally dependent on it. It is therefore not surprising that the Baku and Ashgabat authorities are among the main promoters of the signing of a convention. According to the latest official statements, agreement has already been reached over 70-80 percent of the convention, which could be signed at the next summit of the leaders of the five coastal states due to be held this year in Astana, Kazakhstan, on a date that has yet to be determined.

United States

#deals

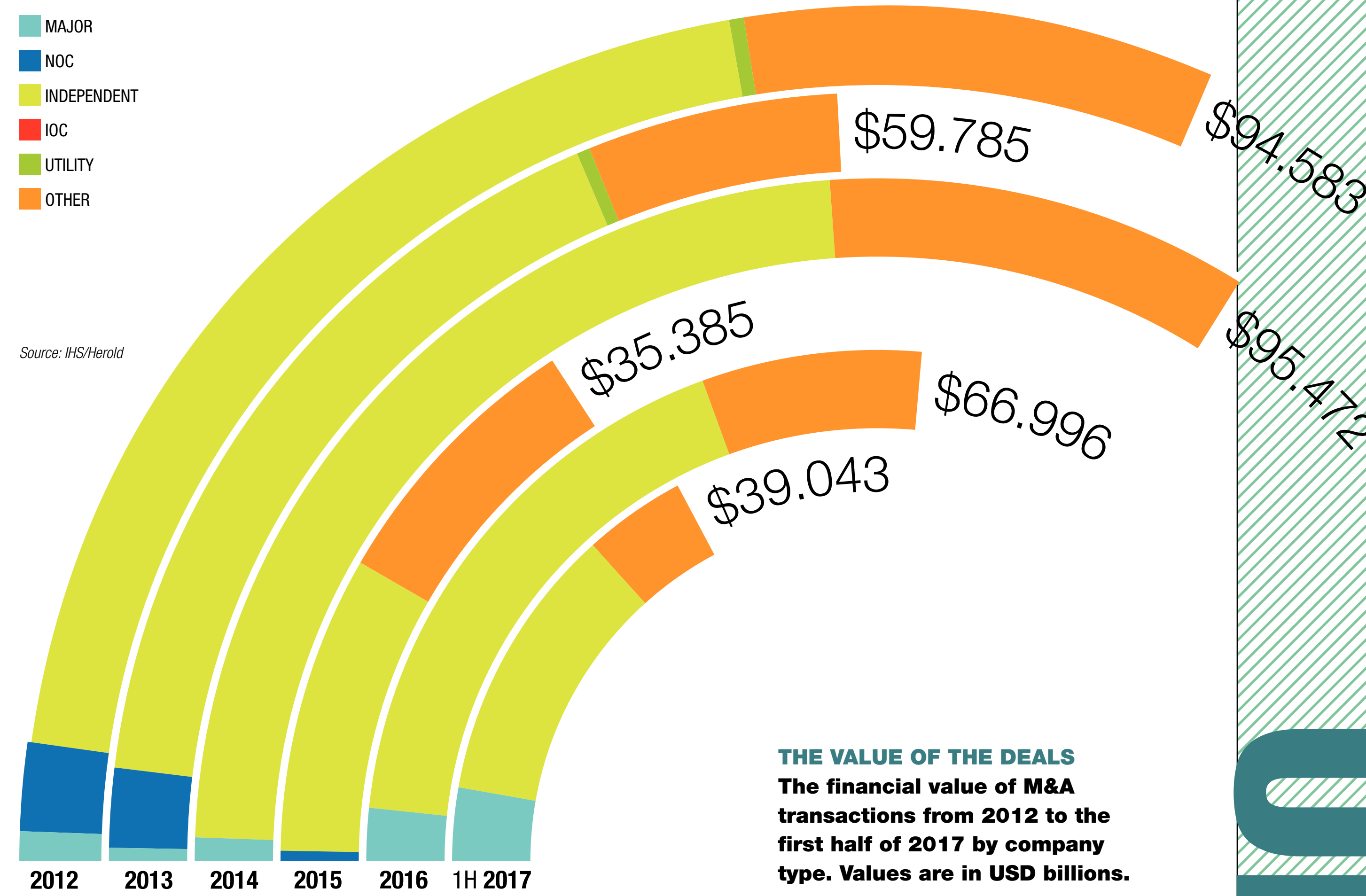
The Stars and Stripes/Two viewpoints

Accelerator on Restarting



ANTOINE HALFF runs the oil program at Columbia University's Center on Global Energy Policy and is a co-founder of Kayrros, having been chief oil analyst of the International Energy Agency, lead economist at the U.S. Energy Information Administration, head of commodities research at Newedge and director of Eurasia Group's energy practice. Bill Clinton called his book, *Energy Poverty*, a "must-read."

PHILLIP CORNELL is a nonresident senior fellow at the Atlantic Council's Global Energy Center. Prior to joining the Atlantic Council, Cornell was a senior corporate planning advisor to the Chairman and CEO of Saudi Aramco.



THE VALUE OF THE DEALS
The financial value of M&A transactions from 2012 to the first half of 2017 by company type. Values are in USD billions.

A Stand-by Revolution

Thanks to the shale revolution, the U.S. occupies a special place on the international energy grid. While in the recent past, deposits such as the Marcellus, Eagle Ford and Anadarko have appeared on the global M&A map, we've recently seen a lull in activity

ANTOINE HALFF

It would have been surprising, given how deeply the shale revolution has reshaped every facet of the oil and gas markets, if this hurricane had not also left its mark on the corporate landscape. In the ten years or so since shale technology really started kicking up dust and taking the market by storm, the small U.S. independents initially involved have gotten bigger and become household names and the darlings of the stock market. They have merged with one another, traded assets, cut costs, revamped their portfolios—when they have not folded. In the process, they have helped revolutionize financial engineering for oil and gas as sweepingly as they have transformed hydrocarbon extraction technologies and upended the old business model of Big Oil (and gas) companies. The dust has yet to settle. From Pennsylvania to North Dakota to West Texas and New Mexico, the winds of change are blowing through the U.S. oil and gas patch. There are as many open questions about shale's ultimate impact on mergers and acquisitions (M&A) as there are about its effect on oil and gas prices, market volatility and the future of oil and gas markets more generally.

The "American energy domain"

By unlocking vast subsoil resources previously deemed uneconomical, shale technology has swept away old fears of resource scarcity and, in the U.S., energy dependence, and replaced them with a heady feeling of abundance and, in President Trump's lingo, American "energy dominance" (whatever that might mean). Thanks to shale's success story, the United States has logged the steepest production growth in oil history. That U.S. shale oil, despite such spectacular growth, only accounts for about 5 percent of world production is beside the point. Its short business cycle and low capital requirements have shaken OPEC and the Majors to the core. Surging shale supply has helped trigger one of the steepest and longest oil price corrections in memory. Shale has rocked the M&A world. Shale has not only put the Marcellus, Eagle Ford, Niobrara, Haynesville and Anadarko basins on the U.S. M&A map, it has made them a focus of activity on a global scale. In 2012, U.S. acquisitions reached about USD 95 billion, led by such shale-focused deals as mining giant Freeport-McMoRan's purchase of Plains E&P for USD 16.8 billion and Access Industries' acquisitions of EP Energy shale assets for over USD 7 billion. Transactions dipped to USD 60 billion the following year, only to bounce back to north of USD 95 billion, a new record, in 2014. With the short cycle and high performance of shale oil and gas making it increasingly tricky to invest in longer-term, big-ticket projects, the growing U.S. shale patch became the place to invest. Oil and gas M&A activity took a hit from the oil price collapse of 2014-15 in the United States as elsewhere, as companies cut spending in a hurry. In 2015, transactions dropped to about USD 35 billion. Yet U.S. shale remained a deal magnet and helped the United States navigate the downturn more smoothly than others. In 2015, shale oil assets continued to dominate M&A activity, led by Noble Energy's USD 3.8 billion acquisition of Rosetta Resources, with assets in the Eagle Ford and Permian Basin, WPX's USD 2.7 billion purchase of First Reserve (Delaware Basin) and Devon Energy's absorption of EnCap, with assets mainly in the Anadarko. In the two years that followed the 2014 price collapse, the United States accounted for about 30% of global deal value, more than twice its share of liquids production (excluding ethanol and processing gains) and much more than its share of natural gas supply. Indeed, in 2016, U.S. M&A activity noticeably diverged from underlying market trends and posted steady quarter-on-quarter gains extending into the first quarter of 2017, with most of the deals focused on the Permian Basin, even as oil prices struggled to hold on to a short-lived, late 2016 recovery. Against the background of virtually no big oil project being sanctioned anywhere and exceptionally few oil discoveries, this renewed appetite for deal-making brought U.S. transactions back up to almost USD 70 billion in 2016, and USD 39 billion in the first half of 2017. Most of the latter deals were front-loaded in the first quarter. Then M&A activity in the US shale patch came to a screeching halt.

The history of the last years of assets and strategies

While the rise of U.S. shale oil and gas is the overarching narrative running through much of the U.S.—and indeed global—M&A activity of the last few years, that headline story conceals large shifts in the type of deals, asset size and quality, location, cast of characters and strategic rationale of the transactions. The history of the shale craze is a play in five acts.

ACT I is the time of the pioneers, when shale companies were still in their infancy. Measured in deal size, this heroic age doesn't quite yet register. This is the archetypal rags-to-riches story, an epic of risk-taking, persistence and ingenuity leading to untold rewards, a high-tech remake of the Rockefeller founding myth. Its self-made heroes are Rocky Balboas of the oil patch: George Mitchell, Harold Hamm, Mark Papa… This is the stuff of breezy page-turners like Gregory Zuckerman's The Frackers and Russell Gold's The Boom. There is an acquisition side, as well as a technical side, to this story: Zuckerman and Gold tell how competing "frackers" raced to build up a critical mass of drilling rights in fragmented parcels from individual landowners in promising plays. But the point was to keep things quiet and valuations down, so in transaction terms, these piecemeal deals are just a footnote in M&A history.

ACT II marks a change of pace, a golden age of frenzied deal-making and rising premiums against the background of the commodity super-cycle and widespread perception of an endless bull market. "The age of easy oil is over" is the mantra of the day as confidence grows that oil prices will never again fall below $100/barrel. Shale's success, first in natural gas, then in oil, takes center stage, quickly crowding out other prospects. Major oil companies jump on the bandwagon and prove more than willing to pay through the nose: ExxonMobil famously agrees to fork out USD 41 billion in stock for shale-gas producer XTO Energy in a deal completed roughly two years before spot Henry Hub prices plunge below USD 2/million Btu in 2012. Exxon's then CEO Rex Tillerson later admits that the deal had been poorly timed. His successor Darren Woods more recently conceded that its price tag, despite a partial recovery in gas prices, had been steep. As weak gas prices prod producers to move to liquids, deal making increasingly turns to oil. The Bakken, which boasts a relatively low percentage of associated gas, is a first focus. A milestone is reached when North Dakota production first tops 1 million bpd in 2014. Harold Hamm's Continental Resources is in the lead, having built up acreage and morphed from small-cap into heavyweight through leasing, strategic trades and small acquisitions. Whiting Petroleum challenges it in production volumes if not acreage with the USD 6 billion takeover of a Bakken pure-play, Kodiak Oil & Gas, announced in July 2014. Earlier deals include Statoil's 2011 purchase of Brigham Exploration for USD 4.7 billion; Exxon's $2 billion acquisition of Denbury Resources' Bakken assets and Halcon Resources' USD→

United States

United States

1.45 billion purchase of Bakken assets from PetroHunt in 2012; and Oasis Petroleum's 2013 takeover of Bakken assets from Roda Drilling and Zeneco also for USD 1.45 billion.
Soon the Eagle Ford of South Texas takes over as the fastest rising producer and most active M&A play. Whereas the Bakken lacks takeaway capacity and suffers from a deepening crude price discount to benchmark WTI, the Eagle Ford enjoys more favorable logistics and access to Gulf Coast refineries. Its high condensate content works out well before the December 2015 lifting of U.S. restrictions on crude oil exports, as condensate escapes the export ban. The steep premium paid by Canada's Baytex Energy for its USD 2.6 billion acquisition of Aurora Oil and Gas in 2014 helps consecrate the play's ascent, following on the heels of Devon Energy's entry into the field with its USD 6 billion purchase of GeoSouthern. Another Canadian producer, Encana, pays USD 3.1 billion in 2014 for conglomerate Freeport-McMoRan's Eagle Ford assets. For both Devon and Encana, the deals are part of a strategic move away from gas. Earlier, U.S. E&P Marathon Oil had bought Eagle Ford acreage from Hilcorp and private equity firm KKR for USD 3.5 billion in 2011. Several foreign oil companies use U.S. joint-ventures to buy into the play in 2010 and 2011: China's CNOOC with Chesapeake Energy, Korea's KNOC with Anadarko Petroleum, Norway's Statoil and Canada's Talisman with private firm Enduring Resources, and India's Reliance with Pioneer Natural Resources.
THE THIRD ACT of the U.S. M&A play starts when oil prices head south in June 2014. Thanks to the industry's ingenuity, production has grown at break-neck pace, turning shale into a victim of its own success. As oil markets fall, so does global M&A activity, which hits its lowest level in more than a year in 3Q2014, both in the number of deals and total value. U.S. M&A activity stays on track for its strongest showing in six years, though. Encana buys Permian player Athlon Energy for nearly USD 7 billion, on top of Whiting's USD 6 billion Kodiak deal. As signs of "lower-for-longer" prices take hold of the oil market in late 2014-early 2015, U.S. M&A activity continues to diverge from global trends, but the deals start changing. While many U.S. buyers had aimed to capture the upside of an everlasting bull market, in the downturn U.S. investments turn defensive.
In most U.S. plays, drilling activity edges down as lower oil prices trim budgets. The Permian Basin bucks the trend and emerges as the sector's biggest success story. Well productivity →

The Main M&A
[2012/2017]

In 2012, acquisitions in the United States amounted to approximately USD 95 billion, the largest being Freeport McMoRan's purchase of Plains E&P for $16.8 billion, followed by EP Energy's sale to Access Industries of assets in the Permian Basin, Eagle Ford, Wolfcamp, Rocky Mountains and Haynesville for over $7 billion, and the BP's sale to Plains E&P of production assets in the Gulf of Mexico for $6.3 billion.

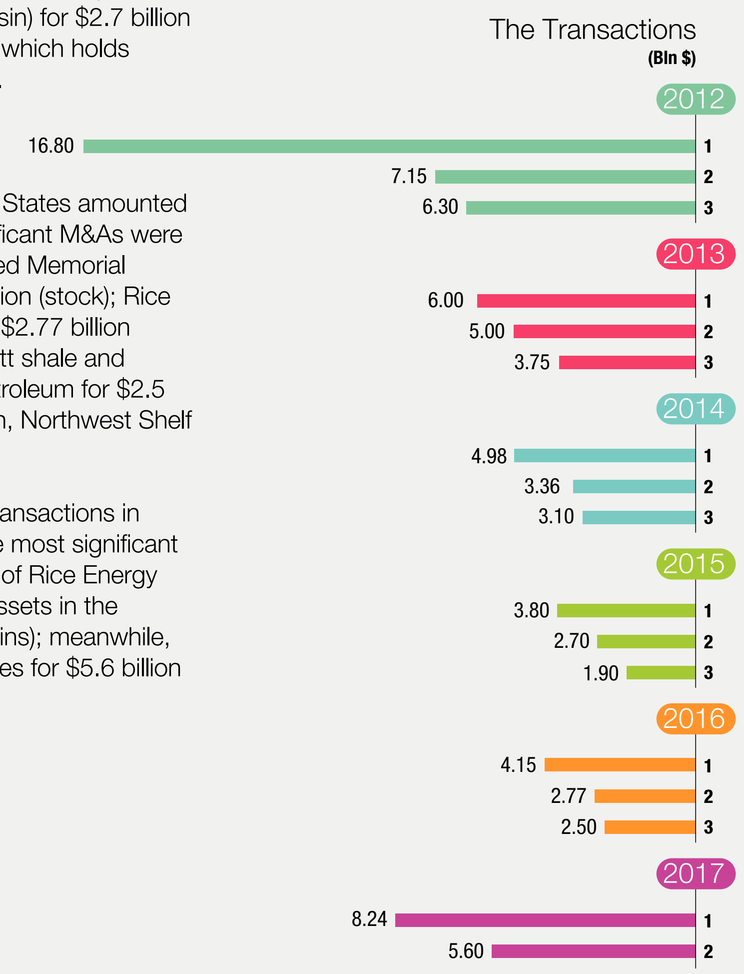
In 2013, transactions amounted to approximately $60 billion. It is worth highlighting the acquisition made by Devon Energy of assets in Eagle Ford from GeoSouthern Energy for $6 billion, the acquisition of Berry Petroleum by Linn Energy for $5 billion and the sale by Apache of production assets in the Gulf of Mexico to Fieldwood Energy for $3.75 billion.

In 2014, transactions reached a record value of over $95 billion. SouthWestern acquired shale gas assets in the Marcellus and Utica basins for almost $5 billion, from Chesapeake, while Breitburn Energy purchased production assets in the Permian Basin from QR Energy for $3.4 billion and Encana acquired liquid-rich assets in Eagle Ford from Freeport McMoRan for $3.1 billion.

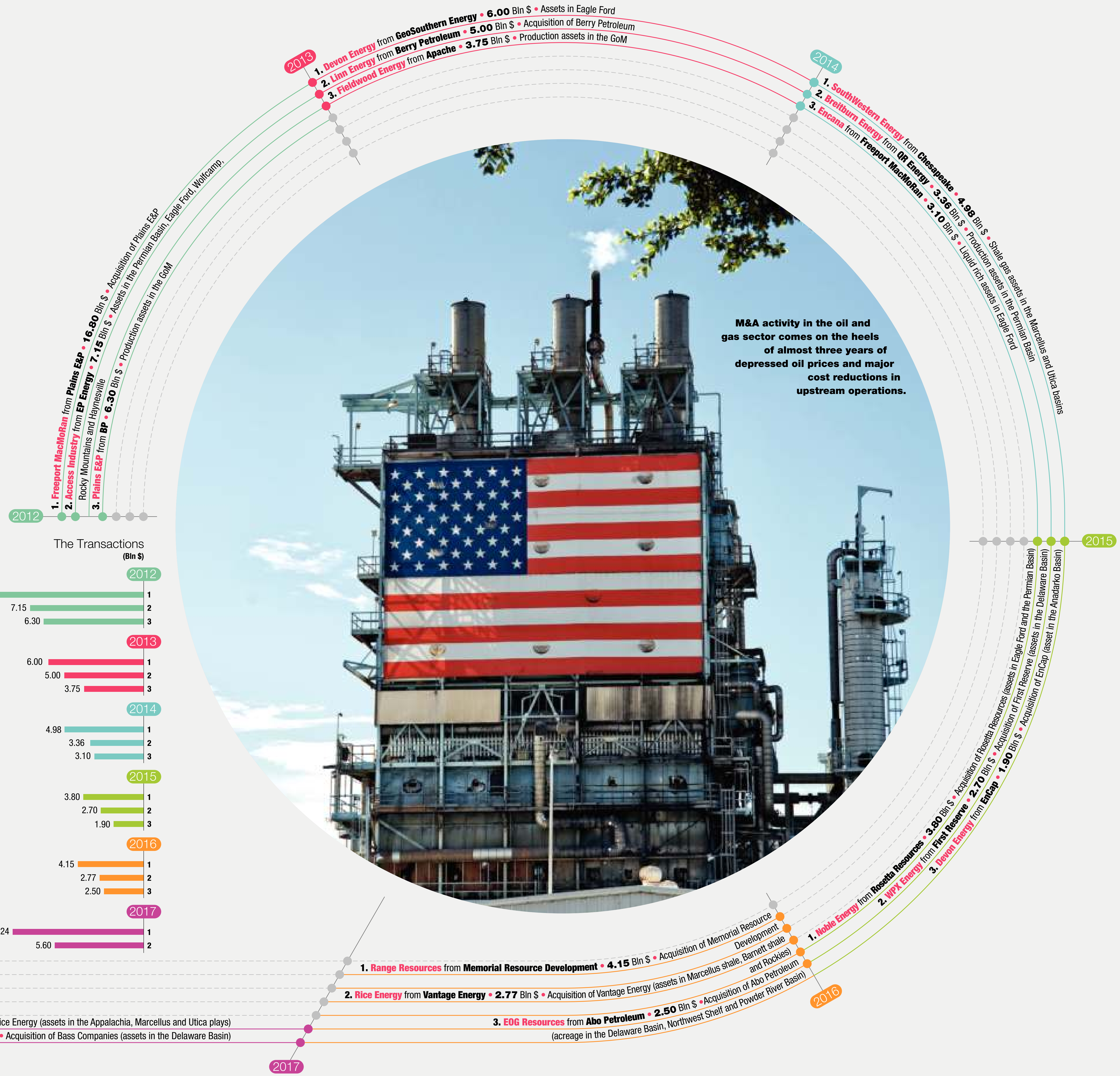
In 2015, transactions declined to approximately $35 billion. Noble Energy acquired the company Rosetta Resources, which holds assets in Eagle Ford and in the Permian Basin, for $3.8 billion. WPX Energy acquired First Reserve (Delaware Basin) for $2.7 billion and Devon Energy acquired EnCap, which holds assets mainly in the Anadarko Basin.

In 2016, transactions in the United States amounted to almost $70 billion. The most significant M&As were as follows: Range Resources acquired Memorial Resource Development for $4.15 billion (stock); Rice Energy acquired Vantage Energy for $2.77 billion (assets in the Marcellus shale, Barnett shale and Rockies) and EOG acquired Abo Petroleum for $2.5 billion (acreage in the Delaware Basin, Northwest Shelf and the Powder River Basin).

In the first half of 2017, M&A transactions in the U.S. amounted to $39 billion, the most significant being EQT Corporation's acquisition of Rice Energy for $8.24 billion in cash and stock (assets in the Appalachia, Marcellus and Utica basins); meanwhile, ExxonMobil acquired Bass Companies for $5.6 billion (assets in the Delaware Basin).



Source: IHS/Herold



Shale Geography

Shale has rocked the M&A world. Shale has not only put the Marcellus, Eagle Ford, Niobrara, Haynesville and Anadarko basins (highlighted in graphics ■) on the U.S. M&A map, it has made them a focus of activity on a global scale. In 2012, US acquisitions reached about $95 billion, led by such shale-focused. Transactions dipped to $60 billion the following year, only to bounce back to north of $95 billion, a new record, in 2014. With the short cycle and high performance of shale oil and gas making it increasingly tricky to invest in longer-term, big-ticket projects, the rising U.S. shale patch became the place to invest.

improves as extraction techniques keep getting better and producers generalize high-performing horizontal wells. While shale "resilience" and fast adaptation to lower prices generally surprises, the Permian Basin outperforms all others and becomes the new magnet of M&A activity, attracting top dollar. Elsewhere, belt-tightening is the main driver: exposure to the commodity boom gives way to consolidation to keep expenses down and streamline operations by combining contiguous assets. Multiple M&A rounds thus see EQT Corporation emerge as the top U.S. gas producer in 1H2017 following its USD 8.24 billion purchase of Rice Energy, which itself had bought Vantage Energy the previous year for USD 2.77 billion. The deal brings together two leading Marcellus and Utica operators in a bid to optimize gas drilling. Unveiling the deal, EQT first says it will save USD 2.5 billion in costs, then points to another USD 7.5 billion in synergies.

ACT IV. A flurry of Permian transactions in late 2016 and early 2017 soon fizzle, however, ushering in Act IV. Ten years into the boom, deals suddenly are few and far between, with just USD 2.5 billion in Permian deal value in 2Q17, and no single deal above USD 1 billion. Investment migrates back to the Marcellus. Both total transaction values and the number of deals drop further in the third quarter, a plunge analysts blame on OPEC's seeming inability to shore up oil prices. That is just part of the story, however. Equally significant may be the market's eroding confidence in shale's growth potential. After years of cost cutting and aggressive consolidation, the sector is running out of improvement options. Well productivity gains reversed in mid-2016 amid mounting signs of congestion and cost inflation. Production growth has slowed. Even in the Permian, there are signs of headwinds. Assets have become pricey. Second-quarter corporate earnings have disappointed. Permian gas-oil ratios are rising, and some companies have lowered their guidance. Some investors are talking publicly about shorting shale stocks. While it is too early to tell how long the fourth act will last, the mood swing is tangible.

Predictions are still difficult

ACT V has yet to be written. What could bring an end to the current lull in U.S. M&A deals? Several scenarios can be imagined, all of which likely require a realignment of shale valuations and crude markets. That could come through either a recovery in underlying oil markets or a downturn in shale assets.

After three years of low capital spending, non-shale oil and gas production seems set to decline, paving the way for a supply shortfall. Meanwhile, despite growing speculation about "peak oil demand," consumption growth is robust. Political risk has never been higher. A price rebound, perhaps as surprising to many market participants as the collapse had been three years ago, could trigger the next major round of M&A activity and provide private equity firms, which play an increasingly large role in the shale patch, with the exit opportunity they need. Absent an oil price recovery, a new round of efficiency gains could rekindle investor appetite. Shale companies, facing diminishing access to financing, could mark down their assets. Alternatively, national oil companies (NOCs) could make a new bid for shale properties. At the time of writing, there were unconfirmed reports of Saudi interest in U.S. shale gas assets. In all scenarios, buying interest might be ready to move away from its strong shale focus of the last few years. Shale resources will certainly remain an essential part of the supply mix for decades. As the sector matures and markets continue to rebalance, however, their disruptive effect might start to fade, and investment might partly migrate back to longer-term, capital-intensive projects.

Key Word: Consolidation

The rebalancing of oil prices and new energy policies have encouraged many U.S. companies to pursue acquisitions, as obvious benefits are to be found in the technology, utility and renewables sectors. But the prospects for a full recovery are still uncertain

PHILLIP CORNELL

Consolidation in the U.S. energy industry has been occurring across a variety of sectors, from oil and gas, to services, to power and renewables. Very different dynamics are at play in each sector, but across the board there is a trend toward mergers around specialized capabilities and technologies, as well as shoring up holdings by existing operators to improve efficiency. M&A activity in the oil and gas sector comes on the heels of almost three years of depressed oil prices and major cost reductions in upstream operations. Global oil and gas companies cut expenditures by almost 40 percent between 2014 and 2016, hundreds of thousands of people were laid off, and major projects were either shelved or cancelled altogether. The American shale revolution in light tight oil (LTO) and shale gas created an entirely new business environment and market dynamic with shorter lead times and well life-cycles, developments that meant the tap could be turned on and off more quickly. This fundamental change engaged a plethora of smaller operators who ran small numbers of wells situated in a patchwork of drilling sites. In the past few years as low prices pushed many of these tiny producers out of the market, the sector has seen significant consolidation not under traditional majors, but under a few dominant companies like Chesapeake Energy, EOG Resources, and Whiting Petroleum. Indeed, the story is the same in much of the energy sector, where consolidation is taking place within specialty sectors rather than under the guise of conglomerate energy companies. With prices appearing to have stabilized at a higher point than than those of the past couple of years, improved cash flows meant that the first half of 2017 saw M&A activity pick up substantially across the global oil and gas sector (USD 137 billion versus USD→

we

United States

87 billion in 1H 2016). Much of this focused on asset-based deals, adjusting upstream portfolios to achieve scale in core areas or reduce exposure in non-core areas.

An active start to 2017

The U.S. accounted for USD 42 billion of global M&A activity in 1H 2017, which was concentrated most starkly in the LTO producing Permian Basin, where 44 deals totaling USD 20 billion were realized. Entry positions in the Permian were staked out long ago. Operators there have moved on to focusing on add-ons that enhance existing development opportunities. Notable was a USD 3.2 billion 71,000 acre expansion by Noble Energy, which intends to increase production there and improve near-term cash flows. Indeed, much of the M&A activity in the Permian involved land acquisitions to rectify the patchwork landholding that limited some of the most efficient horizontal drilling, which can extend tens of kilometers. The result is likely to be more LTO production that is profitable at lower oil prices. The Marcellus Basin saw seven deals in 1H 2017 worth USD 10 billion, the most important the USD 8.2 billion purchase of Rice Energy by EQT Corporation. This prominent corporate-level deal focused on natural gas assets, making EQT the largest producer of natural gas in the U.S. and the dominant player in the Marcellus/Utica. As a result in the future EQT will be able to take a disciplined approach to asset management in line with market and infrastructure developments. When it comes to unconventional oil and gas production then, the story is largely one of existing operators consolidating their holdings to achieve efficiency improvements both in terms of technology use and portfolio management. While driven by existing players, those moves have been supported by private equity funding in both upstream and midstream deals. Private equity was involved in deals worth USD 13 billion in 1H 2017, investment focused primarily on the Permian. That has helped to facilitate consolidation in the midstream sector as asset rationalization may provide opportunities to offset the slowdown in organic growth in pipeline expansions.

The dynamism of the technology sector

M&A activity in the oil field services (OFS) sector also points to the rise of consolidation around specific technological capabilities. GE's acquisition of Baker Hughes is a bid to create a business focused on more efficient well operations through automation, enhanced imaging, and data analysis. Ensco acquired Atwood Oceanics to strengthen its position in technologically advanced deep and shallow water offshore drilling. In March, Weatherford and Schlumberger announced the creation of OneStim, a joint venture combining their North American land hydraulic fracturing pressure pumping assets, multistage completions, and pump-down perforating businesses. And in the largest deal in the sector in 2017, Wood Group acquired AMEC Foster. The goal there was to reap the benefits of increased scale and a more diverse customer base. Tight margins and uncertainty among upstream projects encourages service providers to seek access to customers in other segments including power, refining, chemicals, and infrastructure.

Price and the evolution of U.S. oil & gas

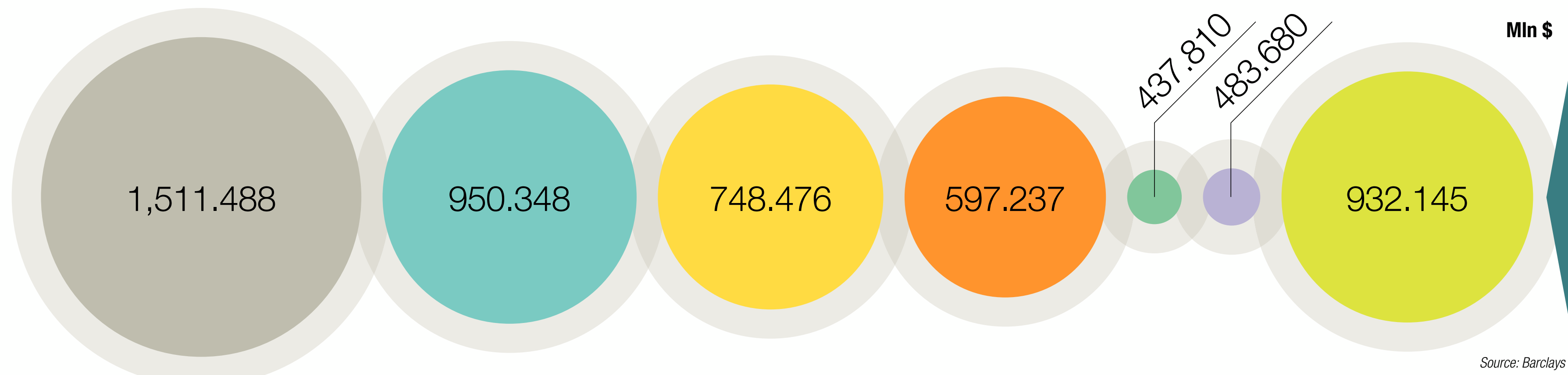
Looking forward, future consolidation in the oil sector will be a product of stable prices. 2017's accelerated M&A activity was partly a result of prices finally seeming to stabilize on the heels of the OPEC/non-OPEC deal. A price decline later this year or early in 2018 (as a result either of weakened Saudi/Russian solidarity or macroeconomic weakness affecting demand) could slow the pace of industry consolidation. Higher interest rates and the tightening of liquidity could have similar results. The oil and gas sector is undergoing an evolution. The era of consolidation under large, integrated and generalist energy companies is giving way to a situation where specialist leaders in specific and often technological aspects of the production process are pulling ahead of the pack, and growing as a result. In the future that will require new forms of collaboration that identify and leverage specializations to cooperatively exploit a variety of circumstances. Shifting coalitions of specialist leaders will favor different players at different points in the field lifecycle, rewarding those who are best equipped to extract value at each stage. When it comes to U.S. oil production, recent waves of consolidation better position producers to confront a long-term oil price band south of USD 60 per barrel. The price will be critical to determining U.S. output projections, but landholding consolidation in the Permian and long-reach lateral drilling will make many plays profitable even at USD 30 per barrel.

The growth of utilities and renewables

The utilities sector continues a longstanding trend toward greater consolidation. Rising costs have become the norm for utility planners, together with slowing consumer demand and increased regulatory costs. Even as the Trump administration moves against the Clean Power Plan, the industry is moving towards cleaner generation and more advanced transmission. Part of this is driven by customers themselves, who are demanding more in terms of technology (to monitor their usage and costs) and choice (to source power from clean sources). Scale can be key to providing these at greatest efficiency, and a June EY report found that 59 percent of power and utility executives intend to actively pursue an acquisition in the next year. As utilities face an evolving market, confronting technological, regulatory, and consumer demand changes, they realize that there are too many threats on the horizon to stand still with their monopoly business. Both Duke Energy and Southern Company spent a great deal of money in 2016 buying wind and solar projects and adding to their natural gas portfolios. With declining returns on regulated contracts renewable energy projects with long-term energy delivery contracts can provide predictable earnings. No wonder that transmission and distribution and renewable energy assets backed by power purchasing agreements dominated Q1 2017, accounting for 78 percent of the quarter's M&A total. The popularity of renewable energy projects reflects a widespread acceptance that, despite current political winds, future value is in sustainable generation solutions. Just as reliance on public policy made a weak case for alternative energy in the past, companies cannot bet on Trump policies to favor legacy fuel sources or dirty generation methods when considering multi-decade investments. The writing is on the wall.

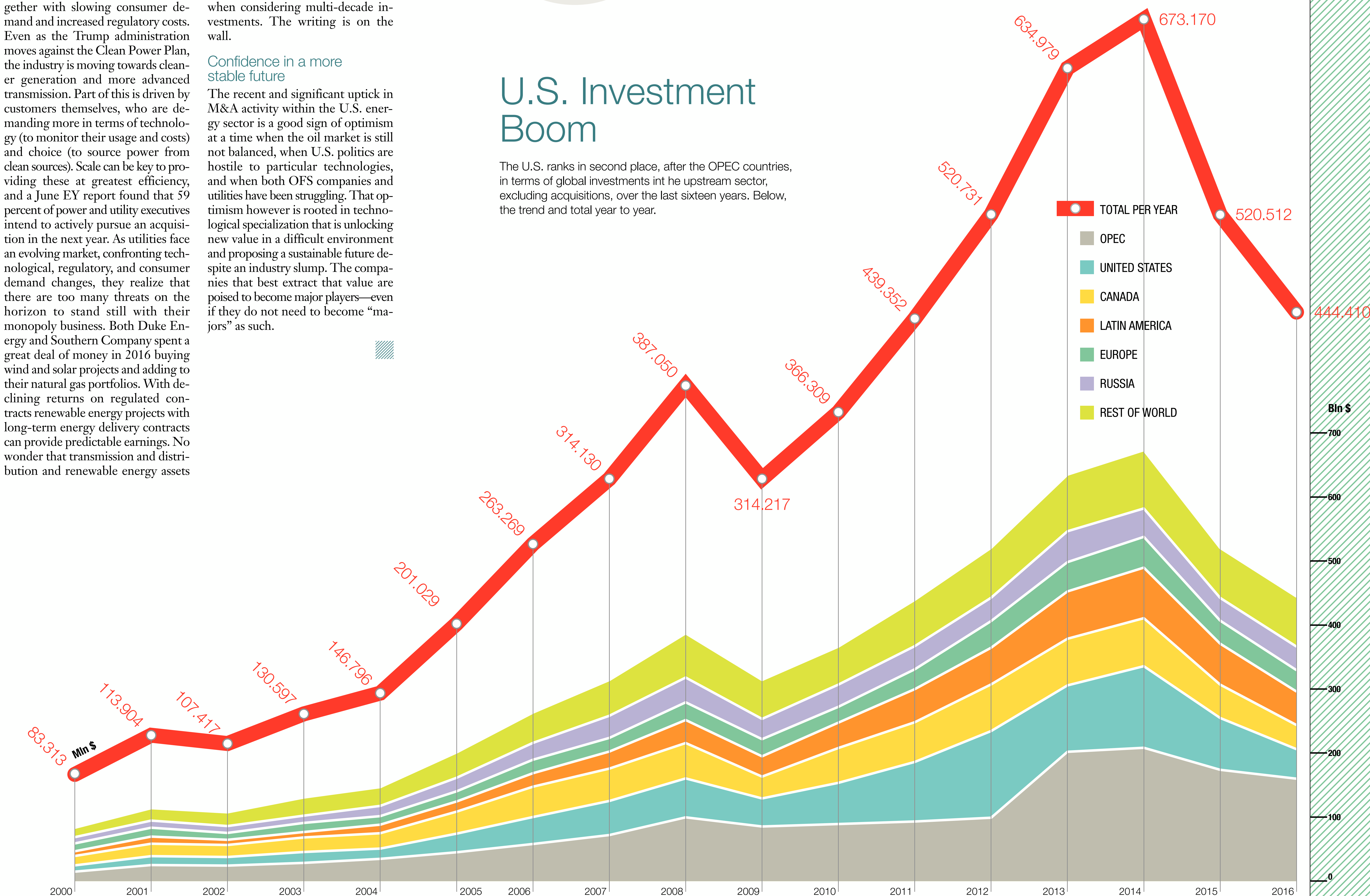
Confidence in a more stable future

The recent and significant uptick in M&A activity within the U.S. energy sector is a good sign of optimism at a time when the oil market is still not balanced, when U.S. politics are hostile to particular technologies, and when both OFS companies and utilities have been struggling. That optimism however is rooted in technological specialization that is unlocking new value in a difficult environment and proposing a sustainable future despite an industry slump. The companies that best extract that value are poised to become major players—even if they do not need to become "majors" as such.



U.S. Investment Boom

The U.S. ranks in second place, after the OPEC countries, in terms of global investments int he upstream sector, excluding acquisitions, over the last sixteen years. Below, the trend and total year to year.



Canada

#deals

Overseas Scenarios/
Between obstacles and advantages

The Steps of an Evolving Market

Following the M&A boom in 2012 and its subsequent decline, Canada's energy landscape is going through a period of change, with potential for upside as obstacles turn into opportunities

PAUL KRALOVIC

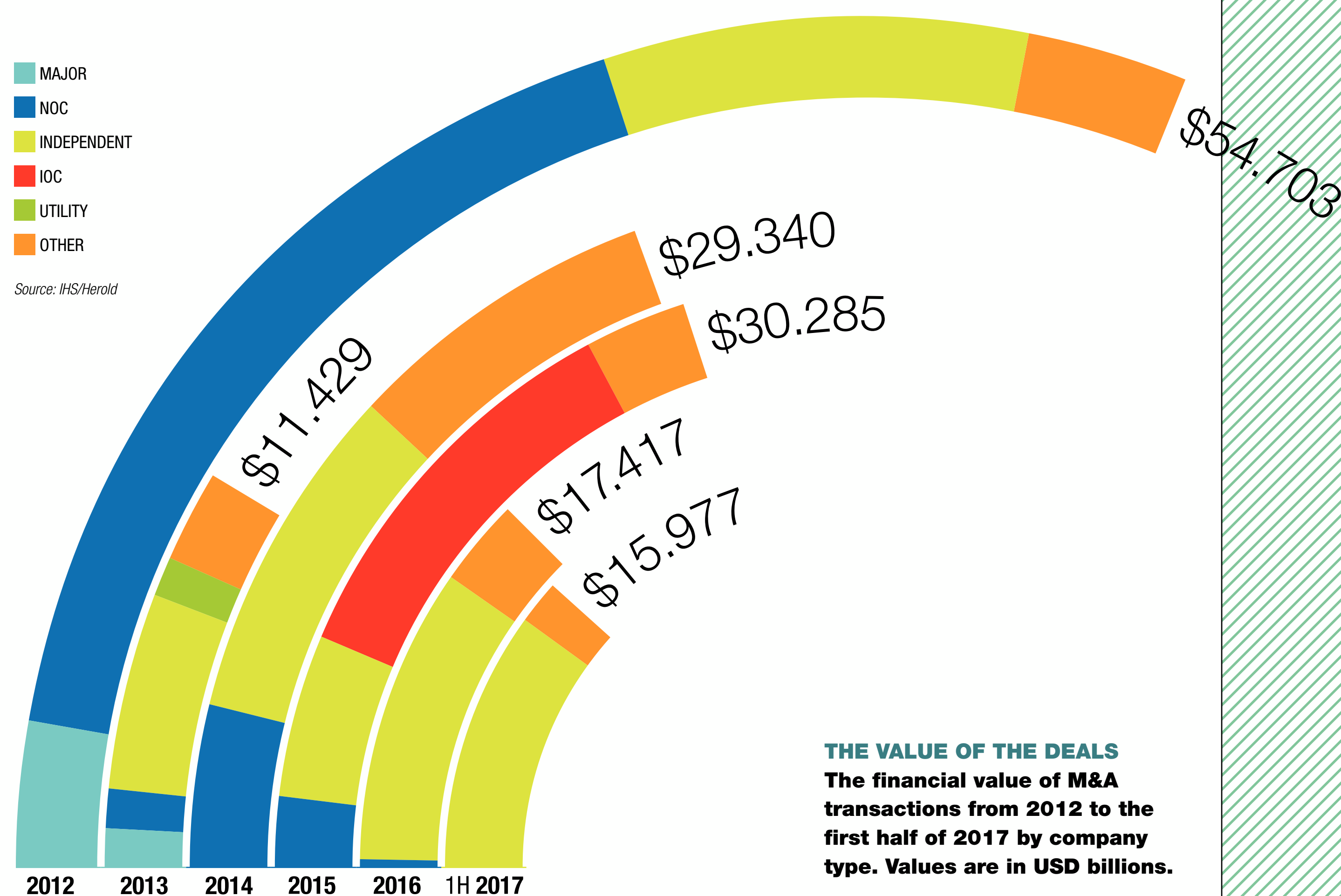
He is a Research Director at the Canadian Energy Research Institute (CERI) and has worked in various research and analyst settings for nearly 20 years. Mr. Kralovic holds a Master's degree in Economics, specializing in International Finance, from the University of Calgary.

In May 2017, Shell Canada decided to offload its CAD 4.1 billion stake in Canadian Natural Resources Ltd. (CNRL) it had acquired as a part of a deal it had made earlier this year to withdraw from the Canadian oil sands. Despite this divestiture, the long-time player and pillar in the Alberta oil patch maintains a strong presence in the province; however, the deal does signal a changing energy landscape in Canada, particularly over the past several years. Factors that drive mergers and acquisitions (M&A) include efforts to increase market share, expansion/changes to asset portfolios (diversification), a desire to gain entry into new markets, efforts to improve efficiencies and profitability, execution of corporate strategies and, in some cases, basic survival. Analyzing in parallel the Canadian upstream mergers and acquisitions between 2012 and the first half of 2017 and the price of oil, we will note that these M&A have occurred in a context that has deteriorated crude oil prices (see chart on page 61). The price of oil declined substantially from mid-2014, from a WTI market price of USD 105/bbl in June 2014, to a low point of USD 30/bbl in February 2016, before rebounding and settling at USD 47/bbl in July 2017.

While less reported, the price of natural gas also declined considerably, from USD 6 per MMBtu in February 2014 to a low of USD 1.73 per MMBtu in March 2016—the latter being the lowest since December 1998. Similar to crude oil prices, gas prices have stabilized in 2017 and are hovering just below the USD 3 per MMBtu level. There is little doubt that crude oil and natural gas prices are impacting M&A activity in Canada. Over the past five years, Canadian M&A activity can best be described in two parts, before mid-2014 and after mid-2014, the point at which commodity prices began their decline.

After the crisis, a record level is reached in 2012

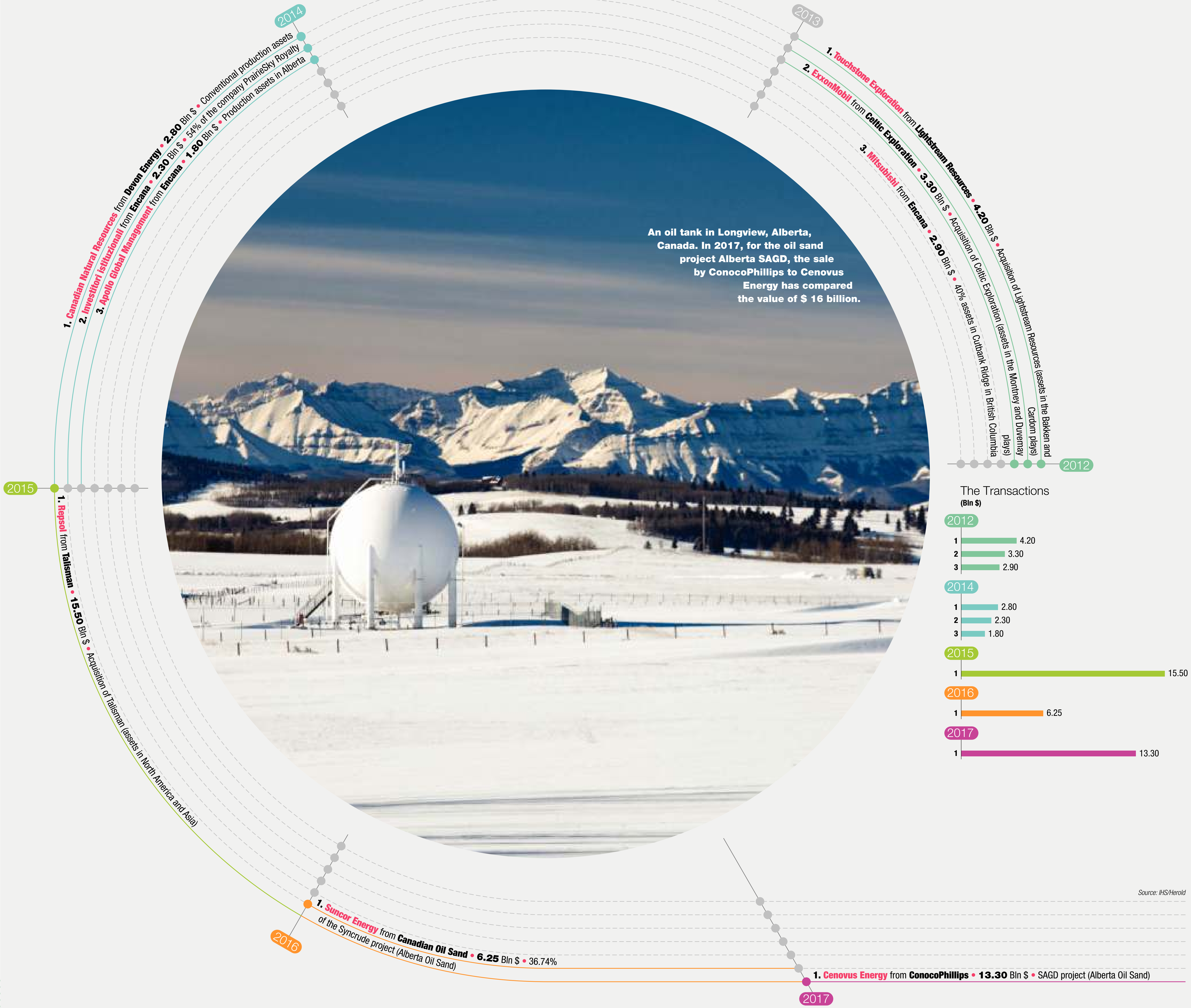
By all accounts, 2012 was an exceptional year for M&A activity, not just in Canada but globally. Emerging from the financial crisis of 2008-09, national oil companies (NOCs) and large international oil companies (IOCs) continued to invest aggressively in global oil and gas assets. The value of transactions increased, reaching a record value of USD 55 billion in 2012, with the highest value transactions being China National Offshore Oil Corporation's (CNOOC) USD 17.9 billion acquisition of Calgary-based Nexen and Malaysian-giant Petronas' purchase of Progress Energy for USD 5.85 billion. Well-funded Asian NOCs secured energy supplies to satisfy increasing demand for energy resources to fuel economic growth while IOCs gained access to reserves through acquisitions and joint ventures. Generally targeting unconventional reserves, such as Canadian oil sands and shale gas plays (i.e. Montney and the Duvernay), both types of companies helped build momentum for upstream M&A activity. The record value of global up- →



THE VALUE OF THE DEALS
The financial value of M&A transactions from 2012 to the first half of 2017 by company type. Values are in USD billions.

Canada

stream M&A deals reached in 2012 was largely the result of five high-value corporate acquisitions. Aside from the CNOOC and Petronas acquisitions, other notable M&A included: ExxonMobil acquisition of Celtic Exploration, which held assets in the Montney and Duvernay basins, for USD 3.2 billion and Encana sold 40 percent of its Cutbank Ridge assets, located in British Columbia, to Mitsubishi for USD 2.9 billion.
However, the wave of NOCs and IOCs securing assets in Canada subsided in 2013. With the exception of the USD 1.44 billion purchase of Talisman's Montney acreage by Petronas and Centrica/Qatar Petroleum's purchase of Suncor Energy's Alberta gas assets for USD 1 billion, there were no significant acquisitions in either oil or gas. The global market, as well as Canada, lacked a mega deal, with the global deal value dropping to USD 136 billion in 2013 from USD 192.5 billion in 2012. The lack of Canadian M&A activity, particularly in the oil sands, is likely due in part to the Investment Canada Act (ICA), a federal law regulating large foreign direct investment. With the acquisitions of Nexen, Progress Energy, Celtic and NAL Energy Corporation, foreign ownership was increasing dramatically in the oil and gas sector, spurring debate amongst Canadians about foreign ownership in Canada. The Act and Regulations advises the legal responsibilities of non-Canadians investing in Canada. Marked by the rapid decrease in oil prices, 2014 was a tale of two parts, with the majority of value deals occurring in the first half of the year. Before prices plummeted in mid-2014, Canadian M&A activity was highlighted by CNRL's purchasing of Devon's Canadian portfolio for USD 2.8 billion and a portion of Apache's gas portfolio for USD 0.4 billion. Encana sold 54 percent of PrairieSky Royalty to institutional investors for USD 2.3 billion and Encana again sold production assets in the Alberta region to Apollo Global Management for USD 1.8 billion. By the end of Q1 2014, the deal value doubled to USD 8.4 billion from USD 4.1 billion in 4Q 2013. There were almost USD 30 billion worth of acquisitions in 2014. Many buyers and sellers, however, sat on the sidelines in 2015-16, as the oil markets were deemed weak and volatile. M&A transaction stood at over USD 30 billion in 2015 and only USD 17 billion in 2016. The former was highlighted by the takeover of Repsol of IOC Talisman for USD 15.5 billion while the latter was highlighted by the acquisition by Suncor Energy of 36.7 percent of the Syncrude project (Alberta oil sands) from Canadian Oil Sands for USD 6.25 billion. The low-price environment had →



An oil tank in Longview, Alberta, Canada. In 2017, for the oil sand project Alberta SAGD, the sale by ConocoPhillips to Cenovus Energy has compared the value of $ 16 billion.

The Main M&A [2012/2017]

In 2012, Canada M&A transactions amounted to approximately USD 55 billion. Touchstone Exploration acquired Independent Lightstream Resources for $4.2 billion, ExxonMobil acquired Celtic Exploration, which held assets in the Montney and Duvernay basins, for $3.3 billion and Encana sold 40 percent of its Cutbank Ridge assets in British Columbia to Mitsubishi for $2.9 billion.

In 2013, there were no significant acquisitions, while **in 2014**, there were almost $30 billion worth of acquisitions. Devon Energy sold conventional production assets to Canadian Natural Resources for $2.8 billion; Encana sold 54 percent of PrairieSky Royalty to institutional investors for $2.3 billion and Encana again sold production assets in the Alberta region to Apollo Global Management for $1.8 billion.

In 2015, M&A transactions stood at over $30 billion and the largest of these concerned Repsol's takeover of Independent Talisman for $15.5 billion.

In 2016, transactions in Canada declined to $17 billion. Of these, it is worth highlighting Suncor Energy acquisition of 36.74 percent of the Syncrude project (Alberta oil sands) from Canadian Oil Sand for $6.25 billion.

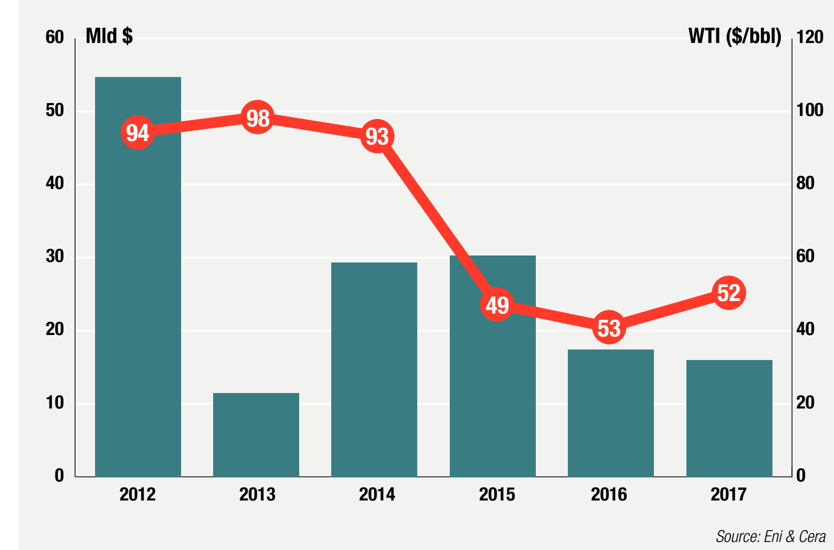
In the first six months of 2017, transactions amounted to $16 billion, including the $13.3 billion (cash and stock) sale by ConocoPhillips of the Alberta oil sands SAGD project to Cenovus Energy.

Canada

CANADA, OIL SANDS LEADER

The graph shows the production of bituminous sands in December 2016: green represents total production and red represents Canadian production (value in bitumen, millions of barrels a day). By the end of 2016, Canadian companies owned and operated 80% of global production.

UPSTREAM DEALS AND OIL PRICES



By analyzing in parallel the Canadian upstream mergers and acquisitions carried out between 2012 and the first half of 2017 and oil prices, we see that these M&A took place in a context that recorded a decline in crude oil prices.

a profound impact on the oil sands, with many international/multinational oil companies divesting their assets. An interesting trend with the exit of the international companies saw Canadian operators enter frequently to purchase their assets. As illustrated by CanOils M&A Database, notable acquisitions by Canadian companies since mid-2014 include (with announcement date in parenthesis):

- ConocoPhillips sold 50 percent non-operated interest in Foster Creek Christina Lake oil sands partnership for USD 17.7 billion to Cenovus (March 2017)
- Shell Canada sold 60 percent interest in Alberta Oil Sands Project (AOSP), 100 percent interest in the Peace River Complex in-situ assets and a number of undeveloped oil sands leases for USD 10.9 billion to Canadian Natural Resources (CNRL) (March 2017)
- Marathon Oil sold 10 percent interest in AOSP for USD 1.638 billion to CNRL (March 2017)
- Statoil ASA sold its oil sands business to Athabasca Oil Corporation for USD 0.578 billion (December 2016)
- Murphy Oil divested 5 percent of its stake in the Syncrude project to Suncor Energy for USD 0.937 billion (April 2016)
- Shell divested its Orion Oil Sands Project to OSUM Oil Sands Corporation for USD 0.325 billion (June 2014).

The bituminous sand business is Canadian

As illustrated by Figure 1.2, as per end-2016, the aggregate of the aforementioned M&A activity has resulted in Canadian companies owning and operating 80 percent of oil sands production; this is up from 55 percent in 2014. And this number could increase, with Canadian producers in the oil sands waiting for opportunities to purchase additional assets at a reduced cost. Many international/multinational oil companies are shifting their capital from the oil sands into other investments, such as U.S. shale. And with oil sands players already operating in an environment of downsized capital budgets, this will likely dampen growth in the industry. As this shrinkage will also have negative impacts on employment and tax revenue for different levels of government, it is not surprising that, in a recent trip to China, Natural Resources Minister Jim Carr suggested that "minds are open" to renewed Chinese investment, taking a step back from the ICA.

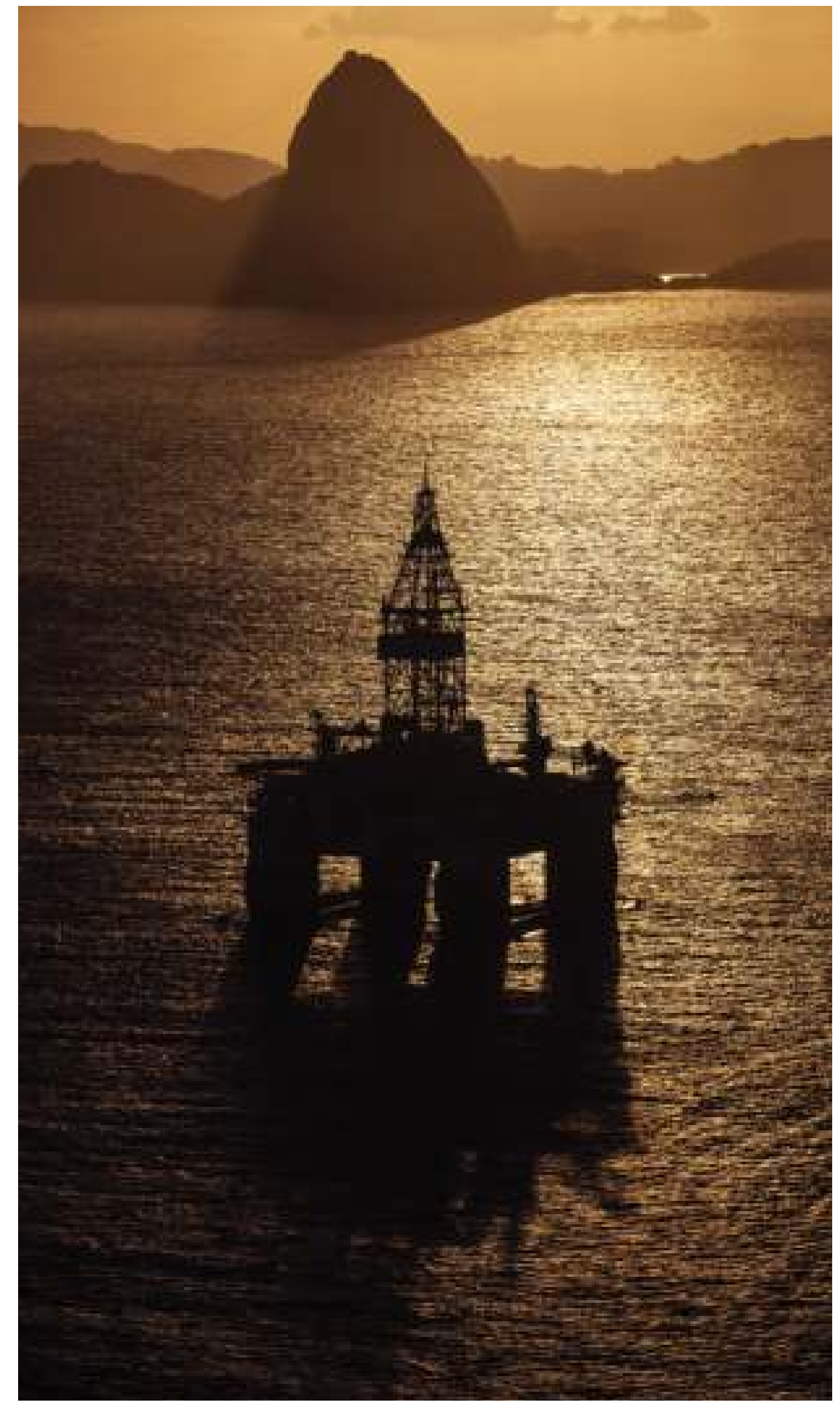
Lower oil prices are not the only factor motivating companies to sell off assets in the oil sands. Other reasons for leaving the Canadian oil sands include high operating costs, limited access to market (highlighted by the well-documented, intense scrutiny of the proposed Keystone XL) and regulatory constraints. Other examples of M&A activity driven by corporate strategy include Shell Canada and Norway's Statoil ASA. Shell is divesting its oil sands assets, shifting their focus from the oil sands to natural gas and electricity. This shift is punctuated by its massive USD 70 billion merger with BG Group in April 2015. Shell is not leaving Canada, but rather shifting its portfolio, keeping shale gas assets, liquefied natural gas (LNG) assets, a refinery and an upgrader. With regard to Statoil ASA's exit from the oil sands, the company divested its oil sands assets to change focus from the oil sands to core activities, including offshore Newfoundland. While no longer an oil sands operator, it remains an investor in the oil sands, with a 20 percent share of equity in Athabasca Oil Corporation. On the flip side of the coin, Canadian companies are purchasing international assets in the oil sands for several reasons. First, they are securing assets at a reduced cost, likely from multinationals fueled by either a pessimistic outlook or the desire to pursue higher returns on investment in other oil and gas plays. Second, their outlook is more optimistic, not just in terms of the price of crude oil but also in the opportunity to take advantage of the cost and operational efficiencies of the acquired assets. Some of the purchasers of the assets include Canadian majors such as Cenovus, CNRL and Suncor Energy. All possess core expertise in the extraction and development of the oil sands, reflecting higher efficiencies, those sometimes realized in low steam-oil ratio and lower operational costs. These companies will likely utilize cost efficiencies, economies of scale and application of their core expertise. Companies could focus operations by basin, taking advantage of synergies between existing sites that lead to spurs of innovation that can reduce operating costs and emissions. CERI estimates the potential of new technologies to reduce emissions by 18 percent and costs by 61 percent in brownfield projects. The implications are thought-provoking.

Natural gas, a radically transformed market

The natural gas side of the equation is equally interesting. The North American natural gas and oil market has been transformed by the emergence of the so-called "shale revolution." Advances in horizontal drilling, 3-D seismic technology and hydraulic fracturing have enabled gas and tight oil production growth from basins that were once thought uneconomic. In 2016, U.S. total natural gas production averaged 77 Bcfpd (billion cubic feet per day), led by shale gas production. As of May 2017, the Marcellus Shale alone produced nearly 17.6 Bcfpd, accounting for approximately 40 percent of the total shale gas production in the US. The production of the underlying Utica Shale is 4.4 Bcfpd. While this is positive for Pennsylvania, West Virginia and Ohio, this growth in production has not only changed the flows of natural gas within the US, but also on a continental scale, with a resultant impact on western Canadian gas producers. Lower cost Marcellus gas is closer to markets in central Canada, the U.S. Northeast and U.S. Midwest, giving it cost advantages over western Canadian gas and displacing it from traditional markets. With increased competition in key markets, western Canadian producers continue to look towards LNG, particularly on the west coast of British Columbia, as potential access to new markets in Asia. This is reflected in Canadian M&A activity, as large Asian national companies, such as Petronas, Mitsubishi, and Petro-China merged and acquired assets in unconventional gas plays in British Columbia and Alberta. In addition, companies such as Sinopec, Korea Gas Corporation, Mitsui & Co., as well as the aforementioned players, bought into LNG projects and negotiated various natural gas and LNG value chain agreements. Much of this activity, however, preceded the drop in natural gas prices in mid-2014. There are currently 19 LNG export proposals along the west coast, following the recent decision of Pacific Northwest LNG to withdraw its application and cancel the project. Despite receiving approval from the Canadian government in October 2016, as well as crossing various other regulatory hurdles, Petronas and its partners (Sinopec, JAPEX, Indian Oil Corporation and Petroleum-BRUNEI) made the decision to cancel the CAD 36 billion megaproject in July 2017, citing uncertainty in the global energy markets. With only a single LNG project, the small Woodfibre LNG facility, announcing a positive final investment decision, sharp eyes will be on other export proposals over the next year or so. There are other LNG proposals but no concrete signals as of yet for a final investment decision. Natural gas M&A activity since mid-2014 has been characterized by smaller value deals, including the presence of private equity investment. The latter is perhaps a sign of a medium term bet on higher gas prices and improved competitiveness in Canadian plays. The recent move by Petronas and its partners to invest is certainly an interesting sign with regard to the growth of the market. M&A activity has been quiet over the past couple of years and will likely remain so for the remainder of 2017. This is contrary to the U.S. shale gas market, which continues to attract foreign companies in various unconventional plays such as the Marcellus and Utica. In Q1 2017 alone, there have been 32 deals worth USD 36.6 billion in the U.S. shale patch. To be certain, the energy landscape is changing in Canada. However, where one may see obstacles, others will see opportunity.

#deals

Latin America



A New Start in the Andes/Ransom and relaunch of the most important fields

The First Successes after the Turn

Market reforms implemented by three of the largest countries in the region have begun to increase investment. These positive signals come after a difficult period in which the region weathered political crises and the fall in global oil prices

NAKI MENDOZA

He is director of energy at the Americas Society/Council of the Americas and he is headquartered in Washington, DC. In the past, he has been responsible for Latin America for the Energy Intelligence Group. His articles appeared on the *Financial Times* and on leading industry publications such as *Petroleum Intelligence Weekly* and *World Gas Intelligence.*

The current year has brought a renewed sense of investor confidence to Latin America's major upstream markets. Investment in the region had been hit hard since 2014 by the drop in global oil prices as well as political and institutional crises that were in motion before prices fell. Fiscal and regulatory burdens on industry, financial constraints of state energy companies, and uncertainties around domestic resource pricing were already present in countries such as Mexico, Brazil and Argentina. Combined with more disciplined capital budgets from oil companies during a lower price environment, the result was a diminished appetite for investment in those markets. But the mood has started to shift. Governments in Latin America have been putting in place regulatory reforms to incentivize greater investment in their respective oil sectors. Those changes have begun to bear fruit in 2017.

The Great Recovery of Mexico

The past 12 months have kick-started Mexico's oil industry. Well before the collapse in prices, the government of President Enrique Peña Nieto passed sweeping reforms to overhaul the country's energy sector and allow the participation of private investment. Production by state energy monopoly Petróleos Mexicanos (Pemex) had dwindled from its peak of 3.4 million barrels per day in 2004 to just above 2 million barrels per day when the reforms were approved in 2013, underscoring the need for private operators to reverse those declines. Initial auctions for exploration and production licenses held in 2015 drew limited interest from foreign investors as industry was still adjusting to the new price realities. But a tide of investment began in earnest with Mexico's first auction for deepwater blocks in December 2016. Considered the "crown jewels" of Mexico's upstream assets, the deepwater round generated heavy interest from international majors. Chevron, ExxonMobil, Total and BP all picked up acreage through a variety of consortia. So too did international firms such as Statoil, INPEX, and Petrobras. China National Offshore Oil Corporation (CNOOC) picked up two blocks as a stand-alone investor, breaking a tradition that saw China's national oil companies typically participate through upstream consortia across Latin America.

In addition to eight of the ten deepwater blocks on offer being awarded, BHP Billiton won a 60 percent interest to co-develop the Trion Deepwater field in partnership with Pemex. The alliance marked the first deepwater farm-out undertaken by Pemex. All told, the assigned contracts licensed in the deepwater round carry an associated investment of approximately USD 34.4 billion over the next 35 years, according to Mexico's energy ministry. The greatest returns from the round, however, will likely come from the wider ripple effect across the Mexican oil sector and the degree of confidence that oil majors have vouched for in Mexico. The Mexican state will receive, on average, between 60 and 66 percent of the profits generated from the awarded contracts. According to Mexico's government, the 10 blocks originally offered contain almost 11 billion barrels of oil-equivalent resources.→

BEFORE THE COLLAPSE IN PRICES
The past 12 months have kick-started Mexico's oil industry. Well before the collapse in prices, the government of President Enrique Peña Nieto passed sweeping reforms to overhaul the country's energy sector and allow the participation of private investment. In the photo, Mexico city.

1. **Shell** and **Total** from **Brazilian Government** • **6.90** Bln $ • 35-year PSC for the development of the Libra project (Brazil pre-salt)
2. **CNOOC** from **Brazilian Government** • **4.10** Bln $ • 35-year PSC for the development of the Libra project (Brazil pre-salt)
3. **PetroChina** from **Petrobras** • **2.60** Bln $ • 100% of blocks X and 58 and 46.16% of block 57 (Brazil)

2013

2014

1. **Qatar Petroleum** from **Shell** • **1.00** Bln $ • 23% of the Parque das Conchas heavy oil project (BC-10) offshore Brazil

2015

1. **Premier Oil** from **Rockhopper Exploration** • **1.00** Bln $ • 60% of the Sea Lion project in the Falkland Islands

2012

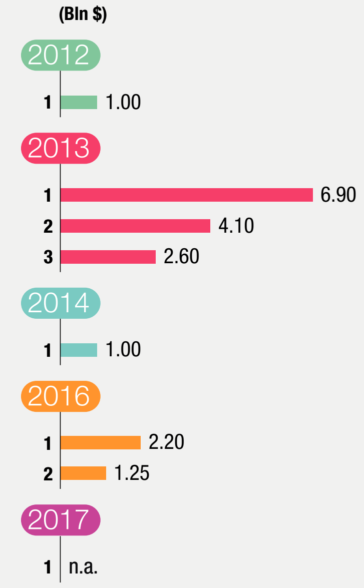
1. **Total** from **Petrobras** • **2.20** Bln $ • 22.5% of the Lara area and 35% in Lapa Field, both in Brazil, in the Santos Basin – pre-salt
2. **Statoil** from **Petrobras** • **1.25** Bln $ • 66% of the exploration license in offshore block BM-S-8

2016

1. **Eni** from **Mexican Government** • **n.a.** • 45% of block 7, 100% of block 10 and 60% of block 14 in Mexico

2017

The Transactions
(Bln $)



Source: IHS/Herold

The Main M&A [2012-2017]

In 2012, transactions amounted to just over USD 6 billion and the only one of significance was Premier Oil's acquisition of 60 percent of the Sea Lion project in the Falkland Islands for $1 billion.

In 2013, M&A transactions exceeded $17 billion. Of these, it is worth highlighting Shell and Total's acquisition of the 35-year PSC contract for the development of the Libra (Pre-salt) project in Brazil for $6.9 billion. CNOOC also entered the project with a $4.1 billion disbursement. PetroChina, on the other hand, acquired 100 percent of block X and block 58 and 46.16 percent of block 57 from Petrobas for $2.6 billion.

In 2014, acquisitions amounted to just under $5 billion. The only transaction worth highlighting was Shell's sale of 23 percent of the Parques das Conchas heavy oil project (BC-10) offshore Brazil to Qatar Petroleum for $1 billion.

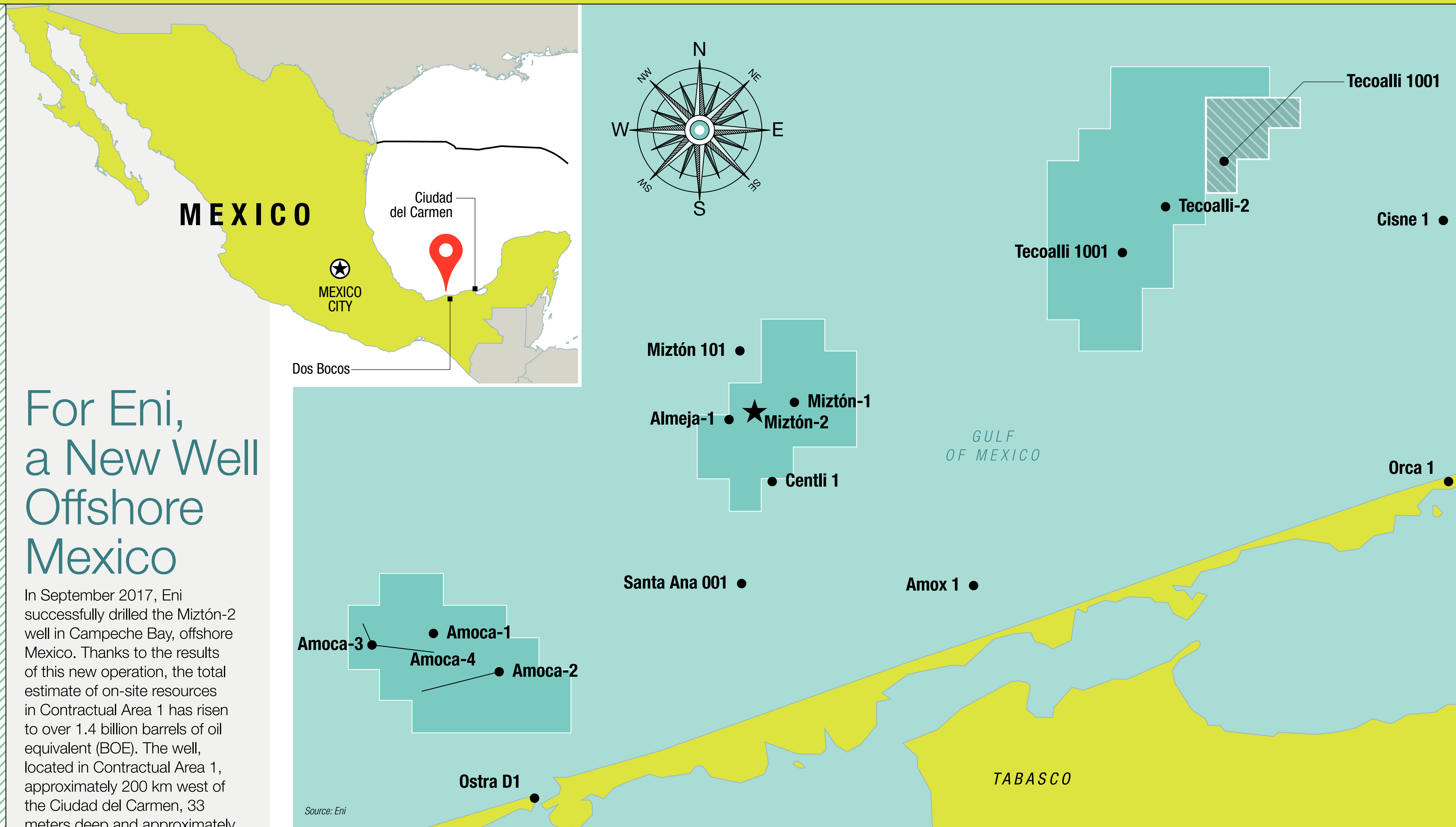
In 2015, transactions totaled just over $2 billion, with none worth highlighting.

In 2016, acquisitions exceeded $6 billion. Of these, it is worth noting the sale in Brazil by Petrobras of 22.5 percent of the Lara area (Santos Basin—pre-salt), which includes the Sururu, Berbigão and Oeste de Atapu fields in the BM-S-11 block, and 35 percent of the Lapa Field (Santos Basin—pre-salt) in the BM-S-9 block, to Total for $2.2 billion. Also in Brazil, Statoil acquired 66 percent of the exploration license in the offshore BM-S-8 block from Petrobas for $1.25 billion.

In 2017, Eni won three bid rounds in Mexico and were awarded 45 percent of block 7, 100 percent of block 10 and 60 percent of block 14 (with operatorship in all blocks).

Juan Carlos Zepeda, head of Mexico's National Hydrocarbons Commission (CNH), estimated that the areas awarded in the deepwater auction could eventually add up to 900,000 barrels per day to Mexico's oil production. Investor interest in Mexico's offshore continued in June of this year when CNH licensed 10 of 15 shallow-water blocks on offer in a subsequent auction. Associated investments for those blocks could reach USD 8.2 billion and add an additional 170,000 barrels per day of crude oil equivalent to the country's production. Resurrecting Mexico's energy production was one of the foremost aims of the reforms. Huge strides were taken towards that objective in July with the announcement of major offshore discoveries. While licensed acreage in offshore auctions represent potential finds, two large confirmed discoveries announced by Talos Energy and Eni are, to date, the most successful materialization of Mexico's energy reforms. The first discovery, a find by a consortium comprised of Houston-based Talos Energy, local Mexican outfit Sierra Oil & Gas, and Premier Oil of the United Kingdom, has been touted as one of the largest shallow-water oil discoveries in the world over the past 20 years. Talos, who operates the block in the Gulf of Mexico off the coast of Tabasco state, reported that the field it discovered holds between 1.4 and 2 billion barrels of oil in place—multiples of its original estimates. Under current prices the discovery equates to around 500 million barrels of potentially commercial reserves. The same day that Talos reported its find, Eni announced that it had struck yet more oil on a previous discovery offshore Mexico and was upping its reserve estimates for the field. The shallow-water Amoca field, Eni notes, now holds at least 1.3 billion barrels of oil equivalent in place, with around 90% being crude oil. To be sure, the precipitous drop in Mexico's oil output over the past 13 years means that the country still needs many more bid rounds that yield additional large-scale discoveries to recoup its previous production levels. According to Mexican energy experts, the country needs about another 10-15 more bid rounds like the December 2016 deepwater auction and around an additional 11 billion barrels of proven reserves to be continually developed to come close to its 2004 output volumes. Fortunately for investors, there is still much more for the taking. The Mexican state has so far awarded just 10 percent of the total 2P reserves (Proven + Probable Reserves) that have been earmarked for public auction, or just 273 million of a total 2.8 billion in proven and probable reserves. Much of what re- →

we



For Eni, a New Well Offshore Mexico

In September 2017, Eni successfully drilled the Miztón-2 well in Campeche Bay, offshore Mexico. Thanks to the results of this new operation, the total estimate of on-site resources in Contractual Area 1 has risen to over 1.4 billion barrels of oil equivalent (BOE). The well, located in Contractual Area 1, approximately 200 km west of the Ciudad del Carmen, 33 meters deep and approximately 10 km from the Amoca discovery, has reached a final depth of 3,430 meters. Eni is also preparing a plan for Amoca Deposit Development Phase 1 (early production), which will be submitted for approval by the local authorities (National Hydrocarbons Commission - CNH), with its startup planned for early 2019. Finally, also last month, Eni signed three new exploration and production licenses in the Sureste Basin, for blocks 7, 10 and 14 obtained following the first international tender for Ronda 2. The joint ventures of the new licenses comprise the following: block 7 Eni Mexico 45% (operator), Cairn 30%, Citla 25%; block 10 Eni Mexico 100%; block 14 Eni Mexico 60% (operator), Citla 40%. Eni has been operating in Mexico since 2006 and created its wholly-owned subsidiary, Eni Mexico, in 2015.

mains will be licensed in a series of bid rounds that have been scheduled for the next five years. The government has identified 509 exploration blocks and 82 production fields that will be put to bid over that time period, providing investors a consistent timetable of what's to come in Mexico's upstream.

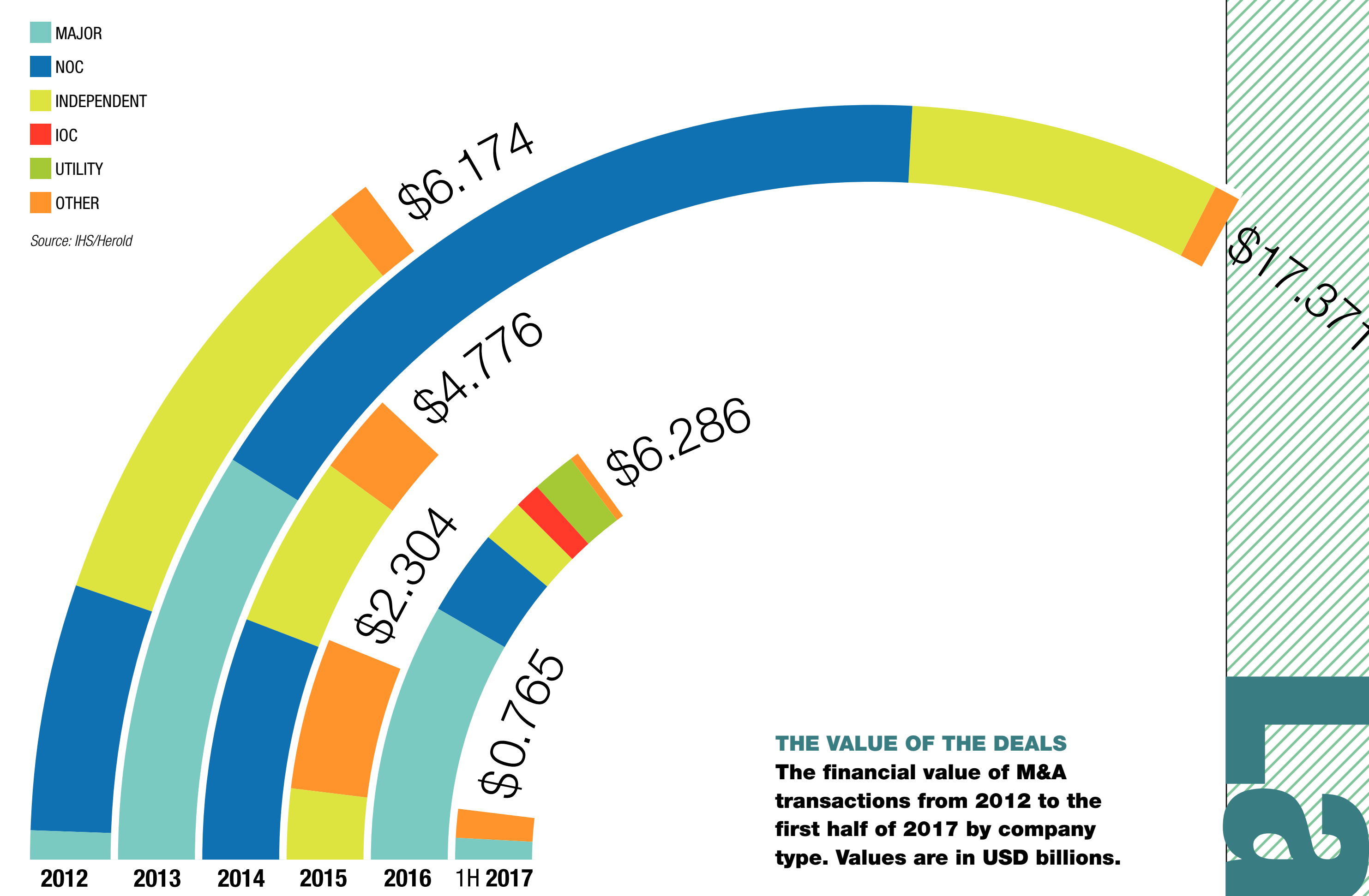
From Brazil, signs of greater consistency and guarantee

Brazil too has ushered in a stronger sense of consistency and security for investors that has begun to realize returns in 2017. Unlike Mexico, reforms that Brazil's government enacted for its oil sector came about after the fall in global oil prices. The makings of the reforms were in motion well before the price drop, but the decline in prices compounded the need for change. The "Operation Car Wash" scandal that has ensnared Petrobras has forced the state-owned oil company, and by consequence, much of Brazilian industry to shift course. The financial fallout from corruption probes, class-action lawsuits, and credit downgrades amplified the company's tenuous footing as the most heavily indebted oil company in the world, with close to USD 120 billion in outstanding debt. As a result, the company launched an aggressive divestment program to raise cash and spin-off non-core assets. Petrobras's five-year business plan for 2014-2018, for example, aimed to invest USD 220 billion. Its current plan covering the 2017-2021 period now stands at just USD 74 billion. Over the next two years, Petrobras is has a divestment plan totaling USD 19 billion. For Petrobras non-core assets essentially constitute anything outside of its offshore pre-salt portfolio. Foreign upstream holdings and domestic natural gas infrastructure are particularly open for outside investment, and Petrobras has already divested billions of dollars of these assets. But even Petrobras's once-dominant hold on pre-salt acreage is more open to outside investors. To alleviate the company of its financial obligations, the Brazilian government reversed a law in November 2016 which previously required Petrobras to hold a minimum 30 percent operator stake in any pre-salt acreage that would be licensed in future. Given the scale of Brazil's pre-salt formations, removing that mandate frees up Petrobras from billions of dollars of development obligations. The opening of the pre-salt coupled with Petrobras's divestment program are being described as the most significant changes in Brazil's energy industry since the formation of Petrobras in 1953. To further incentivize upstream investment, the Brazilian government has also eased local content requirements for future bid rounds, established separate royalties for new frontier areas to incentivize exploration risk, and renewed a crucial "Repetro" customs regime that provides tax benefits for industry. All of these policies conform to President Michel Temer's more market-oriented agenda to stimulate private investment more broadly across Brazilian industry. And they are now being put to the test. Last month Brazil hosted its first major upstream auction since December 2015 and the passing of these new reforms. While just 13 percent of the 287 blocks on offer were issued license, the tender drew more than USD 1.2 billion in signing bonuses—the highest ever sum for an oil and gas auction in Brazil. Like recent offshore rounds in Mexico, the caliber of upstream participants represented a vote of confidence in Brazil's upstream market attractiveness. Most notably, the auction saw ExxonMobil vastly expand its presence in Brazil. The U.S. major picked up ten blocks through the course of the auction—six in a consortium with Petrobras. Prior to September, ExxonMobil had only a marginal presence in Brazil's upstream, owning a few blocks in the country's northern equatorial margin. In contrast, other major international oil companies such as Chevron, Royal Dutch Shell, and Statoil of Norway have long staked Brazil as a core piece of their global activities. ExxonMobil's 50-50 consortium with Petrobras resulted in the lion's share of signing bonuses pledged. The companies offered up a combined USD 1.13 billion in signing bonuses, equal to 93 percent of the auction's total. The two firms also presented the single largest bonus for one area—roughly USD 700 million for a Campos Basin block. Bidding was fierce among the high-profile industry investors: one sum offered by ExxonMobil and Petrobras was five times higher than the runner-up's bid. Another was more than 25 times the second-place consortium of BP and Total. All told, the signing bonuses pledged were more than double the amount that the government anticipated it would collect for the auction. Other big winners included China's state-owned CNOOC and Spain's Repsol, which picked up offshore blocks for USD 7.4 million and USD 7.2 million respectively. In addition to its vindication for market reforms, the auction also serves as an early gauge of interest for two pre-salt bid rounds that the government will host on October 27. The average productivity of a pre-salt well in Brazil's Santos Basin ranges between 20,000 and 40,000 barrels per day and have among the industry's lowest break-even costs. The biggest names and most experienced operators in the global oil industry are registered to bid in what is surely one of this year's most highly anticipated licensing rounds.

Argentina's enger future, the Vaca Muerta shale formation

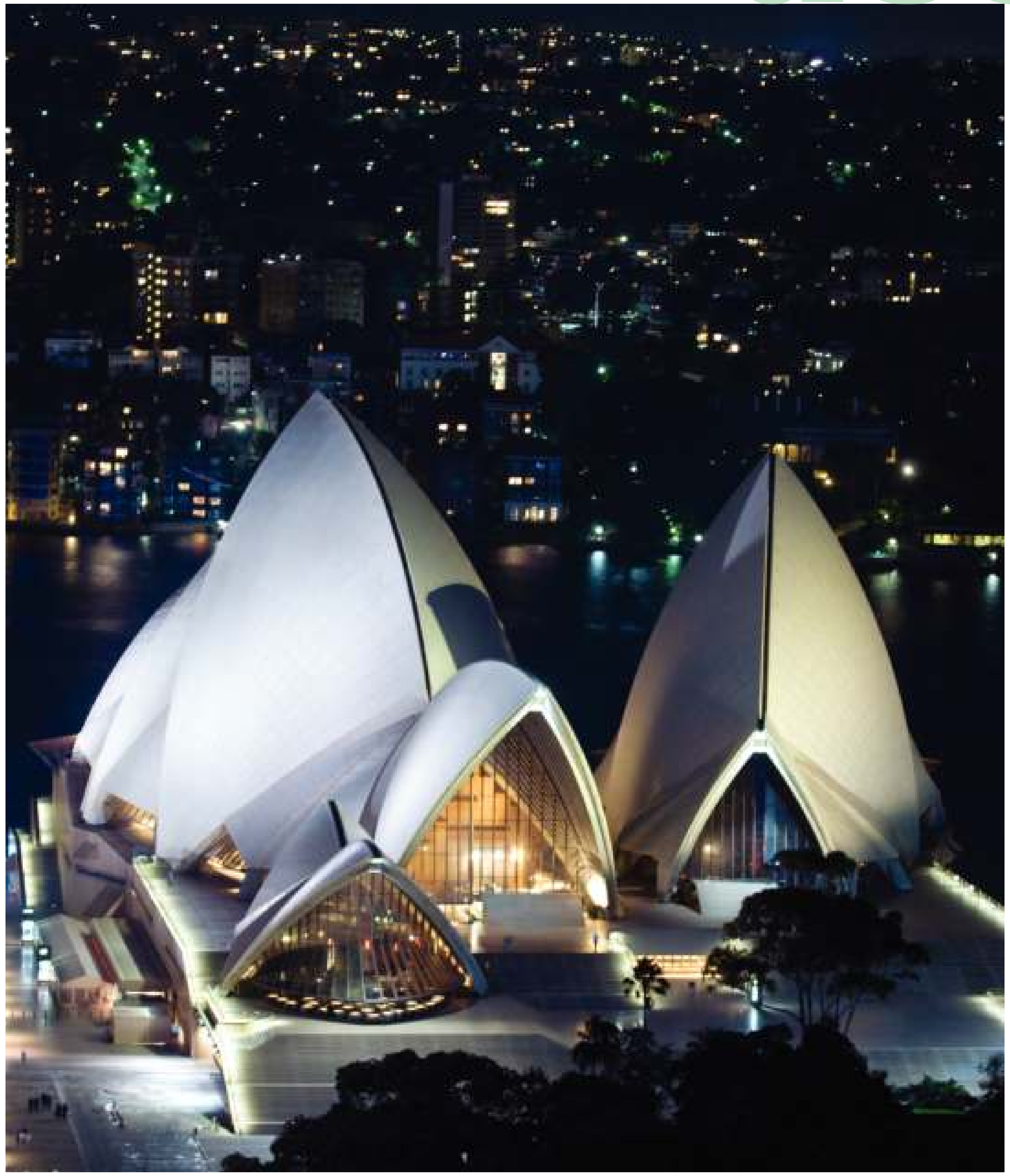
Further south from Brazil, arguably the world's most attractive onshore play is picking up steam. Argentina's Vaca Muerta shale formation is described as the most commercially attractive shale play in the world outside of the U.S. and the epicenter of deal activity in Latin America. Around half a dozen pilot projects in Vaca Muerta are set to transition to commercial development in the next two to three years. Oil output is projected to roughly double from 58,000 barrels per day this year to 118,000 barrels per day in 2019, with natural gas volumes more than tripling over that same period. International investors who have long been skittish about investing in Argentina appear to be growing more confident in the pro-business policies of President Mauricio Macri. Neuquen province, where most Argentina's prolific Vaca Muerta shale play is concentrated, has begun to see a steady increase in upstream investment. The province drew USD 3.2 billion in investment last year—the lowest total since 2012—but projected investment for this year will be between USD 4.5 and 5 billion. The main reason for the uptick is a federal shale gas price incentive announced earlier this year. Under the agreement gas producers earn USD 7.50 per million Btu through the end of next year—a subsidized price that is more than double the U.S. Henry Hub benchmark. Several companies have responded to the program with major new investments. The most significant new commitment has come from Tecpetrol, which plans to spend USD 2.3 billion to produce as much as 10 million cubic meters per day of gas in the Fortin de Piedra Block. Total announced in April that it would invest USD 1.1 billion to develop the Aguada Pichana Este Block alongside Argentina's state-controlled YPF, Wintershall, and a local BP affiliate. Vaca Muerta developments are still largely led by YPF, which operates the only two development projects undertaken so far. The biggest is a joint venture with Chevron in the Loma Campana area which went into development mode in 2014. A smaller, gas-focused project with Dow Chemical is underway at El Orejano. As experience and learnings of the Vaca Muerta proliferate, drilling costs will lower and that will create positive synergies for even greater investment. Costs have already come down sharply. According to YPF, average drilling costs for a horizontal well with around 19 frack stages was USD 8.1 million. That cost compares to last year's average of USD 10.5 million for a well with 17 frack stages.

The backdrop of low oil prices for industry is still very important and remains the principal driver for subdued investment activity across the global oil and gas landscape. But so far, 2017 has offered encouraging signs of an uptick in investment in Latin America as a result of market reforms put in place by three of the region's largest countries.



THE VALUE OF THE DEALS
The financial value of M&A transactions from 2012 to the first half of 2017 by company type. Values are in USD billions.

Australia&Oceania



#deals

Australia & Oceania

Challenges of the New Continent/A controversial wealth

The Promises of Fracking

The eyes of many energy giants are on the vast shale gas reserves of the Cooper Basin. Yet while gas exports are booming, there is not enough gas for domestic consumption, and the Australian government is under pressure to force the exporting companies to direct part of their output to the domestic market

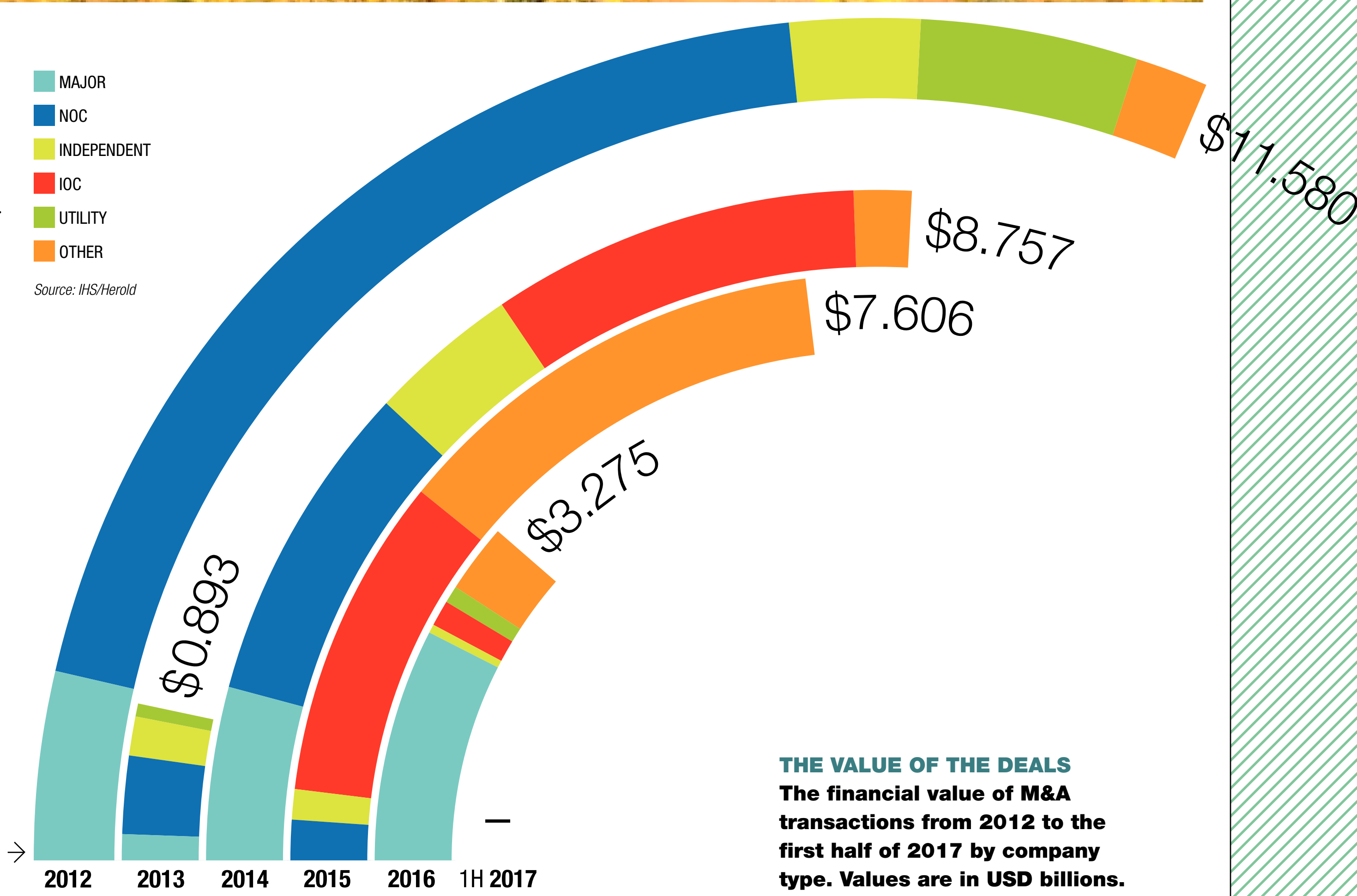
ELENOIRE LAUDIERI DI BIASE

Elenoire Laudieri Di Biase is a sinologist at Melbourne University, Australia, and Ca' Foscari University, Venice. She is a Senior Analyst on Asia for the NATO Defense College Foundation and Editor in Chief for Europe of the Australian *Segmento* magazine. She has authored numerous studies on China and writes articles on economic, diplomatic and cultural topics for various Chinese government and Italian publications.

Mergers and Acquisitions in Australia's oil and natural gas sector fell from AUD 9 billion in 2014 to AUD 8 billion in 2015 and just over AUD 3 billion in 2016. But lately there has been an upsurge of M&A particularly in regard to shale gas, as Chevron and other giants have begun acquiring extraction rights from small and medium-sized local companies in huge areas of central Australia.
Fracking is enjoying a boom here. Unlike in the United States, where it is widely used, in Australia most takes place in desert lands thousands of kilometers away from human settlements and therefore raising little concern from environmentalists.

The race for the Cooper Basin

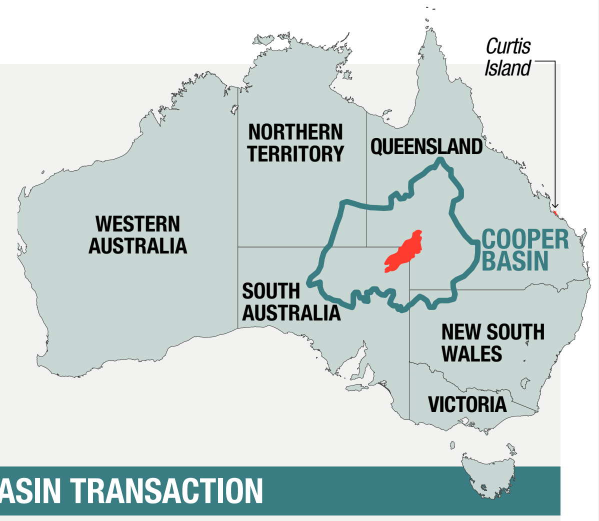
Australia is the new frontier of shale gas production, and the multinationals are moving in to exploit it. Their attention is particularly focused on the Cooper Basin in central Australia, where Chevron has invested AUD 350 million in a partnership with local company Beach Energy. The Hong Kong-based Cheung Kong Group outbid APA Group to acquire gas distributor Envestra for AUD 2 billion, while Britain's BG Group has just signed a contract to buy 10 percent of recently established Drillsearch Energy, which owns extraction rights to part of the Cooper Basin.
BG Group's highest-profile investment of AUD 20 billion involves the construction of a gas export plant on Curtis Island off the coast of Queensland, which will earn it major contracts to supply methane gas to Asian markets. Two other Australian companies, Origin Energy and Santos, have built liquefaction and export plants on the island, which is particularly suitable for mooring LNG tankers. The installations will help to meet growing demand from the industrialized nations of Asia, and that demand is fuelling M&A activity in relation to companies owning extraction rights in the Cooper Basin. These acquisitions are so numerous that they are difficult to keep track →



THE VALUE OF THE DEALS
The financial value of M&A transactions from 2012 to the first half of 2017 by company type. Values are in USD billions.

Australia&Oceania

The Big Race to Gas



RECENT COOPER BASIN TRANSACTION

Buyer	Seller	Size	Date	Value	Type
BG	Drillsearch	$120M	Jul-11	$317.90	Farm In
Beach	Adelaide	$110M	Jul-11	$554.20	Acquisition
New Hope	Bridgeport	$76M	Jul-12	$296.11	Acquisition
Drillsearch	Acer Energy	$143M	Oct-12	$490.00	Acquisition
Chevron	Beach	$350M	Feb-13	$900.00	Farm In
Santos	Drillsearch	$15M	Jul-13	$790.00	Farm In
Santos	Drillsearch	$120M	Jul-13	$460.00	Farm In
New Standard Energy	Ambassador Energy	$42.5M	Dec-13	$136.22	Farm In
Origin	Senex Energy	$252M	Feb-14	$838.24	Farm In

Source: Company announcement and research

The exploitation of the Cooper Basin has spurred M&A activity. The table shows significant deals and their value.

of. Nearly all small and medium-sized local companies have been acquired by or merged with multinationals. The sole exception is Real Energy Corporation, which controls a vast portion of the basin and has only AUD 33.5 million in share capital, though it has enough cash to begin fracking for shale gas and oil in an area that is hugely attractive to the energy giants. The company has resisted takeover attempts and seems determined to continue operating on its own account—all the more so under the chairmanship of Norm Zillman who is considered something of a guru of the gas industry. He was the founder and managing director of Queensland Gas Company, starting out with just AUD 20 million in share capital and selling it for a colossal AUD 5.6 billion. So great is Zillman's passion for the project that he came out of retirement to take up the position of chairman of the board. Real Energy Corporation has just AUD 13 million to cover its extraction costs over the next few months, and whether this is enough remains to be seen.

Keeping the domestic market supplied

The future looks very bright for the Australian gas industry, both upstream and downstream. Ironically, though, it is also at the centre of an industrial and political controversy, as there is a shortage of gas for domestic consumption which is verging on emergency levels. The government has repeatedly threatened the three big exporters, Origin Energy, Santos and Royal Dutch Shell, with export restrictions unless they direct part of their output to the Australian market.
The three companies initially dug in their heels, claiming that such limits would bring about a "sovereign risk," but this is very unlikely given Australia's geopolitical advantage over rival gas suppliers: it is geographically closer to some of the world's biggest LNG importers, and transporting gas by sea is very expensive. Qatar, Australia's leading competitor, is locked in a dispute with its neighbors, and supply negotiations between Russia and China have foundered. Also, Australia is about to sign a free trade agreement with Japan, China and South Korea, all big importers of gas, and the government is unlikely to make any decisions that could put this at risk.
Asia is the world's biggest market for LNG, importing 245 billion cubic meters a year, of which only 40 billion arrives by pipeline via Central Asia. From 2015 to 2016, Australia exported 37 million tons worth AUD 16.5 billion, and around 90 percent of this went to Japan, China and South Korea. Australia's gas shortage is likely to bring a substantial increase in domestic LNG prices, which will inevitably be passed on to consumers.

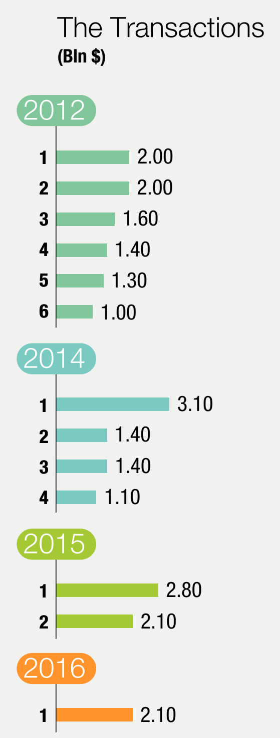
The Main M&A [2012/2017]

In 2012, transactions stood at approximately USD 12 billion and mainly concerned acquisitions of shares in liquefaction plant projects: Woodside Petroleum sold 14.7 percent of Browse LNG to Mitsubishi for $2 billion; CNOOC acquired 40 percent of Queensland Curtis LNG T1 along with 20 percent of the blocks in the Surat Basin and 25 percent of those in the Bowen Basin from BG for $2 billion; PetroChina acquired 8.33 percent in East Browse JV and 20 percent in West Browse JV from BHP Billiton for $1.6 billion; ConocoPhillips sold 10 percent of Australia Pacific LNG to Sinopec for $1.4 billion; Chevron sold an 8 percent share in Wheatstone LNG to TEPCO for $1.3 billion and Chevron again sold a 6.4 percent share in Wheatstone LNG to Shell for $1 billion.

In 2013, M&A transactions were insignificant and **in 2014** they amounted to just under $9 billion. Specifically: Shell sold its 9.5 percent stake in Woodside Petroleum for $3.1 billion, Total purchased 40.1 percent of the Elk-Antelope gas field in Papua New Guinea from InterOil for $1.4 billion, the government of Papua New Guinea acquired 10 percent of the company Oil Search for $1.4 billion and Shell sold an 8 percent share in Wheatstone-Iago and a 6.4 percent share in Wheatstone LNG to Kuwait Petroleum for $1.1 billion.

In 2015, acquisitions amounted to just under $8 billion: Woodside Petroleum purchased 13 percent in Wheatstone LNG from Apache for $2.8 billion and Apache again sold production assets offshore western Australia to Brookfield for $2.1 billion.

In 2016, M&A transactions amounted to just over $3 billion, the most significant occurring in Papua New Guinea with the acquisition, by ExxonMobil, of InterOil for $2.1 billion, which mainly included a 36.5 percent share in the Elk-Antelope gas field.



watch

centers of gravity

NICOLÒ SARTORI

M&A, the Litmus Test of the International Balance of Power

Early 2017 showed encouraging signs of an upturn in the oil sector, an upturn confirmed by a rising number of deals and acquisitions worth nearly USD 140 billion in the first half of the year. A slight rebound in the price of oil driven by the confidence generated by the agreement reached by OPEC in November 2016 boded well for the markets and leading industrial players. However, even though the oil industry is seriously in need of consolidation after tough years of price collapses and severe market volatility, there are still no signs of the major shifts in asset and capital that the new dynamics of the global Oil & Gas sector might need. Instead, we are seeing a confirmation of current trends: North American centrality, European decline, and emerging markets still in search of identity and balance.

America, the center of the world

As in 2016, the North American unconventional industry has been the focus of the main M&A activity in the oil sector this year. With more than three quarters of all transactions in the global upstream sector (worth around USD 70 billion), the U.S. and Canada have established themselves as the most dynamic and attractive markets for the industry and its investors. In particular, the slight rise in crude oil prices has seen operators starting to strengthen their portfolios again, with massive flows of capital into the United States' big productive fields. Over the course of six months, there have been USD 20 billion worth of deals in the Permian Basin alone, with ExxonMobil alone paying USD 5.6 billion into BOPCO's coffers to acquire 250 thousand acres in the basin between West Texas and New Mexico. The American industry's message to the markets therefore seems clear: there is renewed confidence in unconventional production activities and the main players are consolidating their assets and operations to better exploit that position. This development has major implications for global dynamics and elasticity of supply and prices, a seachange potentially detrimental to traditional producers.

Europe on the margins?

On the other side of the Atlantic, Europe remains in a prolonged energy standstill. European hydrocarbon demand and consumption data provide no encouragement, despite timid signs of growth in the gas segment. After problems in the refining sector, the upstream segment is also seeing the departure of major players, who are mostly being replaced by private equity investment, especially in the North Sea. Big players like Engie and Dong Energy have recently abandoned the North Sea. The former sold USD 4 billion in assets to Neptune, a firm owned by American and Chinese banks, and the latter has sold all its positions to the British chemicals company Ineos, which has also acquired the offshore Forties pipeline system from BP. Royal Dutch Shell, in line with its massive disinvestment plan to dispose of USD 30 billion of upstream assets, has also reduced its operating presence in the area, receiving USD 3.8 billion dollars from the sale of fields containing 115 thousand boe/d to Chrysaor. Finally, Maersk's departure from the Danish offshore sector and sale of its historic assets to Total is also significant, not least of all in emotional terms because Maersk is Copenhagen based. These deals not only show the increasing marginality of Europe for major global players but also represent a major strategic alarm bell. Without forward-looking investments Europe risks a further contraction in its production capacity that would threaten the energy security of the entire bloc, which is already highly dependent on foreign imports.

Asia still in search of an identity

The future of the Asian continent remains uncertain. Obviously, in terms of fundamentals and market prospects, everything points east. With population and consumption growth, rapid rates of urbanization and vehicle ownership, Asia clearly has the perfect recipe for a substantial increase in hydrocarbon demand. However, despite solid foundations and exciting prospects, a significant consolidation of industrial balances in the region is yet to materialise. At the moment, the Western majors hold about USD 40 billion dollars of capacity and assets in Asia, which they would be ready to liquidate given adequate financial returns. Nevertheless, investments and transactions in the region seem to be pointing strongly towards the low-carbon segment. In 2016 over half the transactions in the energy sector related to renewable energies—wind, solar, hydroelectric and geothermal —and to electric transport, which is growing rapidly compared to previous years. Returning to the oil sector, it should be underlined that the major traditional producers, which are little inclined to make regional investments in the upstream sector, are moving to intercept the inevitable rise in demand in the region. And if American unconventional continues to dominate the supply side, there are a number of large national oil companies ready to invest in refining and downstream. Following on from Rosneft's mega-deal in India in late 2016 (USD 12 billion for the acquisition of Essar Oil), at the start of the year Saudi Aramco signed a USD 7 billion deal with Petronas to acquire 50 percent of the RAPID (Refinery and Petrochemical Integrated) project, which can process 300 thousand barrels of crude oil a day and produce nearly 8 million tons of petrochemical products a year. Here, too, there is a chance for the growing competitiveness of U.S. oil products to make gains, and only huge investment in the region can slow down the advance of the stars and stripes beyond American borders.

IAI Istituto Affari Internazionali

Nicolò Sartori is Senior Fellow and Head of the Energy Program of the IAI, where he coordinates projects on the issues of energy security, with a focus on the external dimension of Italian and European energy policy.

watch

point of view

ROBERTO DI GIOVAN PAOLO

Leaders, Politics and Decisions: The Media and the Public

The election of Donald Trump is certainly not the first to have brought to power a leader who is so vocal about his hard-line and, in his view, incontrovertible opinions. Indeed, we could say that with him, and to some extent with Emmanuel Macron and Theresa May, the world of what used to be designated as "the leading western democracies" has peaked in its use of language targeted at the public and the media. This is an approach long used by Vladimir Putin although certainly in a less "studied" manner, but an approach also closely linked to a former empire in transition. It seems clear that Trump's announcement that he will not implement and will actually withdraw from, the Paris COP21 agreements is comparable to May's stance on Brexit and Macron's decisions to nationalize STX in the face of the deal with Fincantieri. This use of the media can easily be viewed as a sometimes-necessary response to today's many and widespread populist trends, with associated negativities and psychodramas that generate a strong and decisive language.

The risks of policy announcements

The issue raised here is how much there will be left of these announced choices. How many of these "irrevocable" decisions will truly be such in the contemporary arena of international politics and its agreements? Today many of these announcements have great impact and, thanks to social networks, reach audiences and attract commentary on an unprecedented global scale. This, however, doesn't necessarily mean these proclamations can be acted upon, and certainly not on the strength of a simple declaration.
This surely has an impact on a leadership's approval ratings. In this respect, the Trump-COP21 case is exemplary. He declared his intentions related to climate issues as a presidential candidate, and,as soon as he was elected, he immediately reiterated that the United States would "certainly" pull out of the accord.
But is that really possible? And if so, on what terms? Article 42 of the 1969 Vienna Convention on international treaties clearly sets out the conditions for treaty withdrawal, explicitly referring the grounds for termination to each individual agreement. So, what does the COP21 agreement say? The parties, it states, pledge to stay in the accord until 2020 when, individually or collectively, they will be able to re-discuss their participation. Trump could therefore use this argument, particularly in the run-up to the next presidential campaign, and hope that upon being re-elected he would be able to sit at the table and re-discuss the terms of U.S. participation. He won't be able to do that until then. A similar legal situation applies to Brexit. On March 29, 2017, Britain invoked Article 50 of the Treaty on European Union, which provides for the withdrawal of a member state after two years of intensive joint negotiation. The person appointed to deal with the U.K. is French politician Michel Barnier, a tough negotiator who has served several times as E.U. commissioner and as minister in his own country, and who is expected to deliver a draft for the final deal by October 2018. The agreement will then have to be ratified by the European Parliament, the British Parliament and all the other 27 E.U. member states before Britain's final departure in March 2019. Will Theresa May still be around in 2019?

The game between candidates and voters

And finally, we come to the "grandeur" that characterizes the French presidency irrespective of who lives in the Elysée palace. We could say that, going against France's proverbial grandiloquence, Emmanuel Macron used the media to show how deeply he shared the economic and social concerns of the French middle classes. His call for an "onward march" (En marche) from the grassroots not only took him to the Elysée but also won him a 90 percent parliamentary majority after France's latest legislative elections. After focusing predominantly on domestic policy at the start, he then made a choice that strongly affects Italy by nationalizing the STX shipyard, which was about to be acquired by Fincantieri. With this bombshell, Macron in fact falls squarely into line with the "French-style" market control and privatization policies that Gaullists and socialists alike have always embraced both in the name of a strong state and in competition with Marie Le Pen's FN. Here again, the media impact was the main concern. But what about the actual decision-making aspect? Nationalization, which at first seemed to be an incontrovertible fact, turned out to be an expedient for "negotiating."

A time for greater prudence

Can we draw a moral from this brief overview? Not everything that creates an impact on the old media and the "new" media that includes social networks ultimately delivers the expected outcome. We already knew that. But an era of globalization and multilateralism, including in politics, requires, or rather, would require, political and economic decision-makers to exercise a degree of restraint and prudence perhaps unthinkable in the past. It would be interesting to do a study to verify the percentage of goals achieved by political decision makers from those they explicitly declared outside of election campaigns. Without going into media comparisons, what we find is that multilateralism impacts our lives in a complex world where, in times such as these, political figures, regardless of their ideological background, attempt to simplify their responses by offering immediate relief. And this applies as much to Putin's reassurances to the "Great Russia," scarred by its loss of power with the ending of the Soviet Union, as it does to Trump's "call a spade a spade" talk for a "white" America that views itself as the "underdog," even more so than the poor African-Americans subjected to racial prejudice but defended by Obama. To each his favorite cause. But announced decisions frequently seem to clash with actual practice, and very often they suffer from unexpected ends, which means they don't even provide any certainty about re-election, let alone about real long-term effects.

Roberto Di Giovan Paolo, a journalist, has written for, among others, ANSA, *Avvenire* and *Famiglia Cristiana*. He was Secretary General of the Italian Association for the Council of European Municipalities and Regions, and he is a lecturer at the University of International Studies of Rome.

MARKET DEVELOPMENTS

Prepared by Anna Capalbo, Simona Serafini
and Francesca Vendrame - Eni

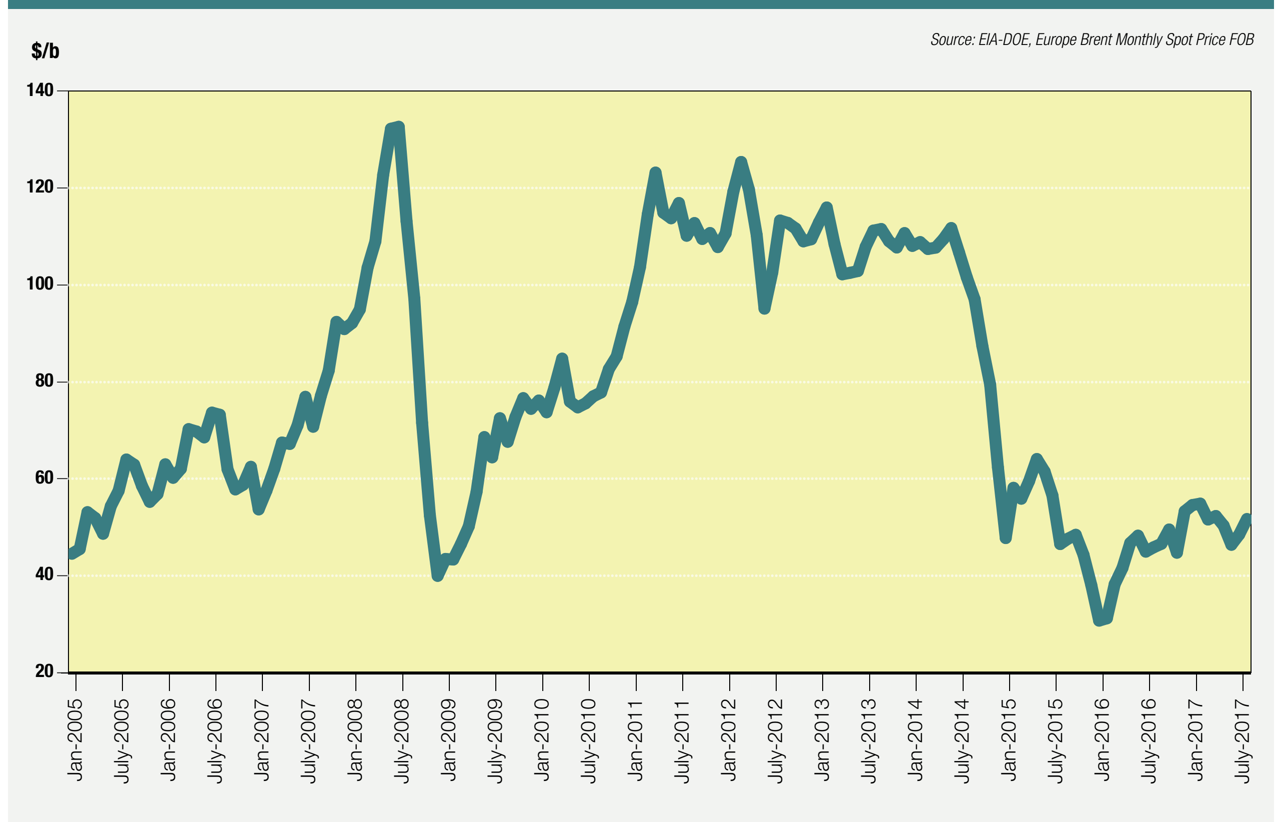
Moving in the Right Direction

OIL PRICES

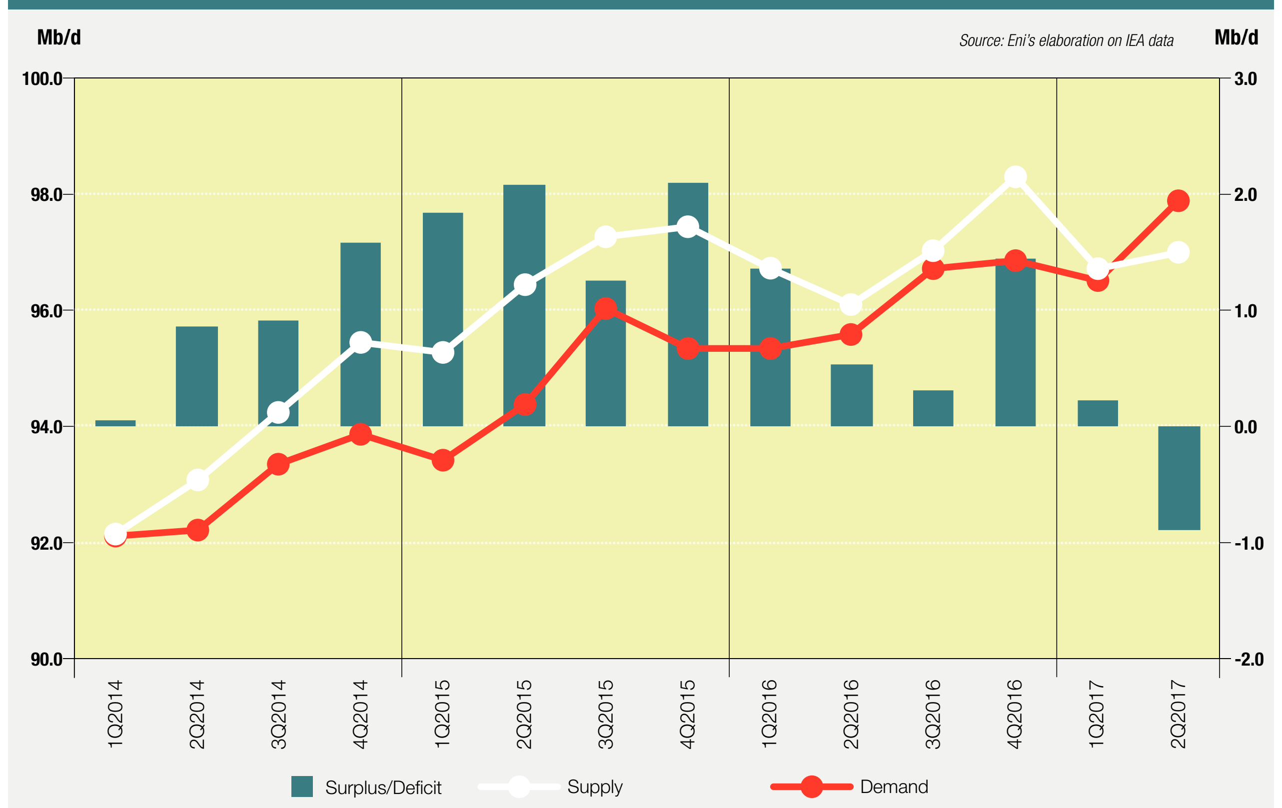
OPEC's discipline has moved it away from the "lower for longer" scenario

Between June and July, the price of Brent dropped below USD 50 per barrel and rose back up to USD 59 per barrel at the end of September, the highest value since July 2015. The financial statements for the quarter closed, for the first time after three years of surplus, with a deficit of 0.9 Mb per day, mainly due to the major OPEC and non-OPEC production cuts policy. This deficit was also partly due to production losses related to geopolitical issues, with the ups and downs of Libyan and Nigerian production and the growing crisis in Venezuela.
The May 25 meeting ended with the OPEC, non-OPEC countries' decision to extend the deal until March 2018, keeping the cuts unchanged. The weak reaction of the market, which appears most concerned about the recoveries of Libya and Nigeria, as well as the progressive growth of U.S. tight oil (from January to August +0.6 Mb per day), brought the price to a low of USD 45 per barrel in July. However, despite U.S. growth, uncertainty remains. Upward revisions due to the growth in demand and greater OPEC, non-OPEC discipline have increased confidence in the re-balancing process and partly draw away from the "lower for longer" market vision. As of mid-August financials have been betting on rising prices, especially on Brent ICE, while on the American market the sentiment less certain about this direction. The hurricane effect has particularly affected demand with the resulting expansion of the WTI-Brent discount. The price structure also reflects the divergence between the two benchmarks. Brent has been moving steadily backwards since September and reducing the affordability of stockpiling. This supports the price rise at the end of September to USD 60 per barrel, according to IEA data, which estimate OECD trading stocks below 2016 levels and almost zeroed floating stocks. In the experts' meeting of September 22, to which Libya and Nigeria were invited for the first time, producers confirmed that the market is moving in the right direction. There is discussion of an expected extension of the agreement beyond March 2018, of the coalition's enlargement and of a possible definition of another target for exports. Decisions have been postponed to the next official meeting to be held on November 30.

BRENT PRICE



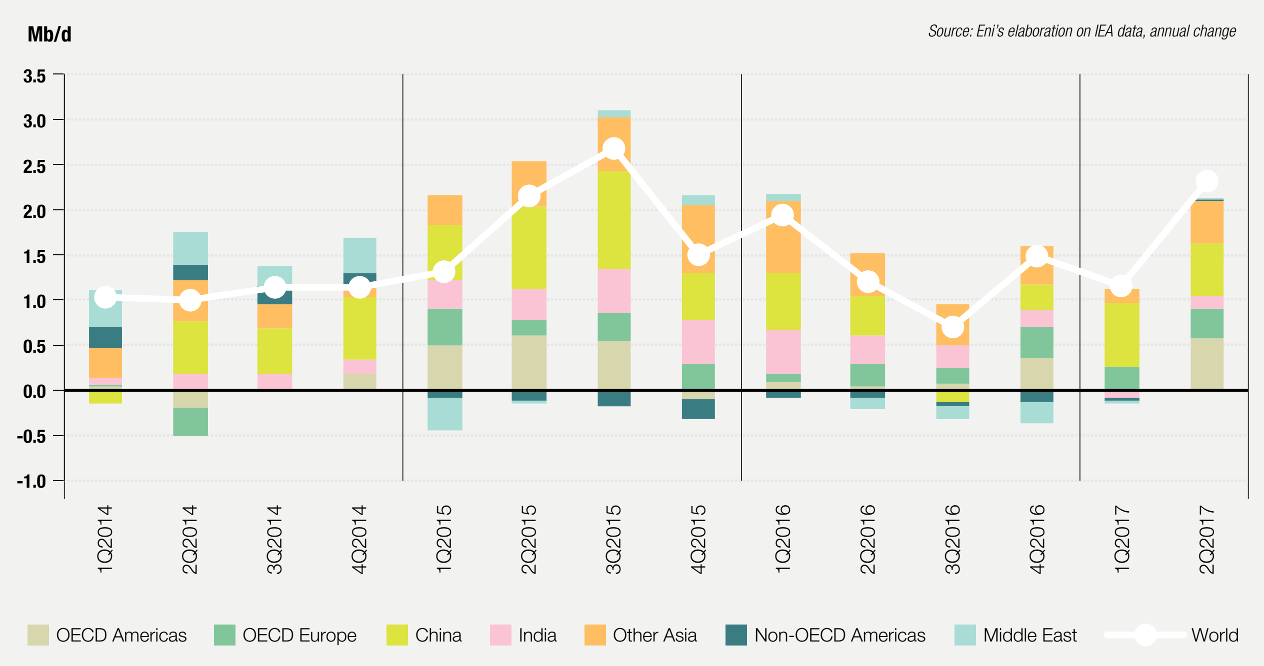
SUPPLY/DEMAND BALANCE



OIL DEMAND

In the second quarter of 2017, the growth in demand compared with last year is reflected in the highest quarterly increases since mid-2015 (+2.3 Mb per day vs. 2Q16), due to the strength of OECD consumption (+1 Mb per day) and the solidity of non-OECD demand. In the OECD, consumption in Europe and the U.S. has benefited from a better economic context and low prices for over two years. In the U.S., in the first half of 2017, the industrial production index rebounded, after falling in 2015 and a substantially stable 2016. The volume of imports was also up, with positive effects on diesel consumption, given that a large volume of imported goods is distributed by truck. A sharp growth also occurred in LPG consumption, reflecting the entry of new petrochemical capacity (ethane crackers). Positive signals also came from Europe, with industrial production accelerating in several countries after a rather mediocre 2016. In Europe, diesel consumption also increased, driving an overall growth in demand. In the non-OECD, China's contribution rose to over 40 percent (+0.6 Mb per day in 2Q17) of the total growth of the area. In terms of products, LPG consumption increased due to the entry of new petrochemical plants. In the first half of 2017, the growth in gasoline consumption slowed down due to lower car use as a result of restrictive measures on city driving. In fact, in order to address serious pollution problems, the Chinese government is imposing limits on car sales and useage through a new lottery system for drivers' licenses; this coming on top of existing targets on the efficiency of new vehicles and incentives for electric and hybrid cars. On the other hand, gas and oil usage increased as a result of the support of industrial production and commercial transport.
A sharp rise in consumption in India (+0.15 Mb per day in 2Q17) resulted from the negative impact on the economy of the demonetization and uncertainty associated with the introduction of the "Goods and Service Tax," a type of national VAT.

ANNUAL DEMAND CHANGE BY SELECTED AREAS



OIL SUPPLY

The global oil supply in the quarter rose to 97 Mb per day (+0.8 Mb per day vs. 2Q16), particularly due to the increase in non-OPEC production (+0.8 Mb per day). U.S. crude oil rose by +0.3 Mb per day compared with the second quarter of 2016 after more than a year of declines; in September, tight oil finally reached levels not seen for two years. Canada also recorded a significant increase (+0.6 Mb per day), compared with 2016, when fires sharply reduced production in Alberta. Good performance continued in Brazil (+0.2 Mb per day), after the start-up of offshore fields in the areas of Lula and Libra. Kazakhstan's production rose as a result of the ramp-up of Kashagan and that of Ghana, due to the Cape Three Points offshore oil and gas field.
Mexico and China were still down, while Russia remained stable, having fallen back below 11 Mb per day, reaching a 100 percent compliance level in August.
OPEC, due to the agreement on production cuts, was also down (-0.2 Mb per day vs. 2Q16). Saudi Arabia and the main Gulf Countries achieved 100 percent compliance, while Iraq, the United Arab Emirates and Algeria were less "disciplined," remaining well below 50 percent. Libya's slow recovery continued (+0.3 Mb per day in 2Q16), though it returned to 1 Mb per day in July, despite the continued attacks on the major oil and gas fields. The situation remained troubled in Venezuela, which gained compliance as a result of its internal crisis, while Nigeria, despite its many difficulties, seemed to have embarked on its path to recovery.
Ahead of the next meeting on November 30, the major producers, led by Saudi Arabia and Russia, are in favor of extending cuts throughout 2018. There is also an intention to expand the coalition to another 10-12 producers between Africa and Latin America, which, overall, account for 50 percent of global production. Compliance with the production cut agreements will play an essential role in rebalancing the market.

ANNUAL CRUDE SUPPLY CHANGE