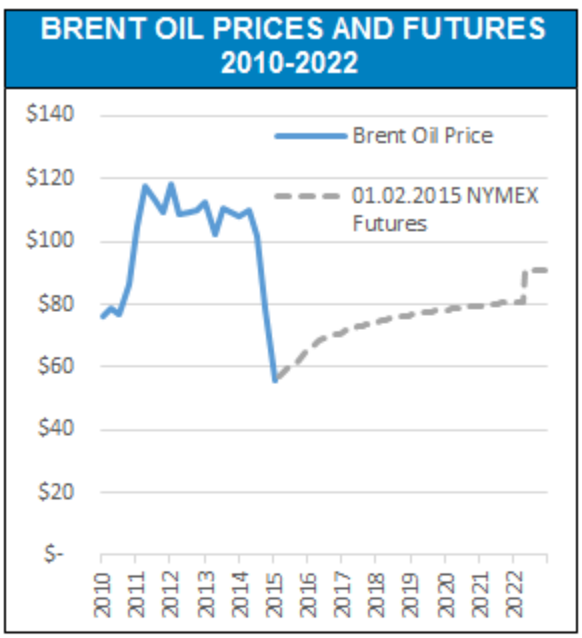
The Oil Price Collapse: The Need for a New Roadmap

Part 1, Resources Economics, January 2015

Dr Albert Bressand

The collapse in oil prices from their June 2014 heights has put an end to three years of unusual stability for what is still the world's premier benchmark price for the energy sector as a whole. More subtly, it has also exposed the weakness of assumptions for what could be called the high-yet-affordable and stable oil prices of 2011-2014. In this memo and its forthcoming sequels we'll endeavor to read through short-term signals by looking at the transformed resources side (Part 1), key players and their economic and policy objectives (Part 2) and possible scenarios departing from the one that presently makes headline news.

Short-term price adjustments, long-term transformation signposts



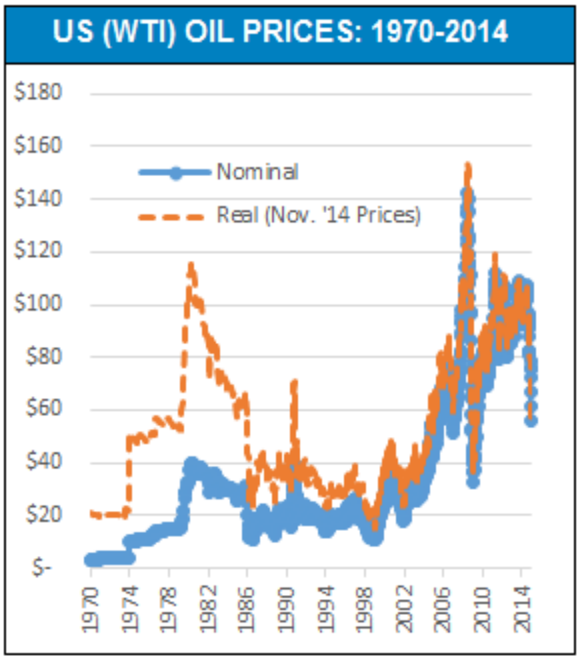
Source: CME, EIA, Econvue

The price story seems both spectacular and routinely familiar. At the start of 2015, the consensus scenario goes like this: with oil prices below half their peak value of June 2014 and with the forward curve in mild contango[1], expectations are that prices will remain depressed and inventories rapidly increasing well into 2015 and 2016 before production of US unconventional oil (largely hedged into 2015) begins to significantly slow down, reducing overcapacity[2]. After a year or two of low prices—in the $40 zone until mid-2015 according to Goldman Sachs--the pendulum, it is assumed, will swing back to sustained high prices at the latest by the end of the decade, as major frontier-oil projects—possibly worth as much as one trillion dollars--are postponed or cancelled by financially stretched companies. Oil-price volatility will be the name of the game once again but the underlying long-term trend will remain one of gradually firming oil prices toward the higher yet still affordable $125/155 level that the International

[1] The CME market for Brent futures closed the year on December 31 at $61.25 for June 2015, $64.93 for December

[2] OECD oil inventories increased by 154 million barrels (mb) in the first 50 weeks of 2014 pushing stocks to 97% of their historical highs. The IEA forecasts that inventories will grow by up to 1.75 mb/d if OPEC maintains production at their stated target of 30 mb/d until the next OPEC meeting in mid-2015. Existing storage capacity could absorb 1mb/d for a year at least (Goldman). On January 1, 2015, the spot price of Brent was about $5 below the forward price for July 2015. Storing oil on VLCCs would could cost about $6 or $7 per barrel for 6 months in charter hire and ancillary expenses according to the Poten energy and shipping brokerage. See "Let It Float: floating storage on the verge of a comeback?" *Poten Tanker Opinion*, December 24, 2014.

Energy Agency (IEA) and the U.S. Energy Information Agency (EIA) see in their two pairs of main scenarios to 2040[3]. Significant upward as well as downward spikes around this trend may result notably from prolonged civil wars in Iraq and Libya, from the possible lifting of sanctions on Iran and, less likely so, from a shift by Russia from its present free-riding of OPEC quotas to a sharing of the role of swing producer with Saudi Arabia. Such spikes notwithstanding, as Saudi Minister Ali Al Naimi put it, the market will work[4].



Source: EIA, BLS, Econvue

Yet, convincing as this consensual scenario may sound, it ignores important potential developments on the productivity and geopolitical side. More is at stake than merely how long it will take for lower prices to reduce non-OPEC supply, boost demand and repay Saudi Arabia and OPEC for the temporary cost of having kept the market in oversupply on the way to, and after the price collapse. Three years of US oil-supply increase of 1 million barrels per day (mb/d) per year on average raise questions about the oil industry's changing structure that are better considered with US (geopolitical and economic) interests and US industry innovation strength fully in mind. Also unaddressed are implications of the present oil-price collapse for the broader energy system of which oil is expected to represent only one fourth by 2040, by then almost on par with natural gas, coal and renewables, against 31% today[5].

The cognitive map that can help make sense of the deeper transformation in energy markets needs to be grounded in political economy and technology, not just economics. This requires to consider four interlocking levels: energy resources, markets, policies, and the underlying power structure[6]. Their interplay will determine how producers and investors will fare.

PART 1. 'OIL' AND HYDROCARBON MARKETS IN THE ERA OF LTOs, NGLs AND PAPER BARRELS

---

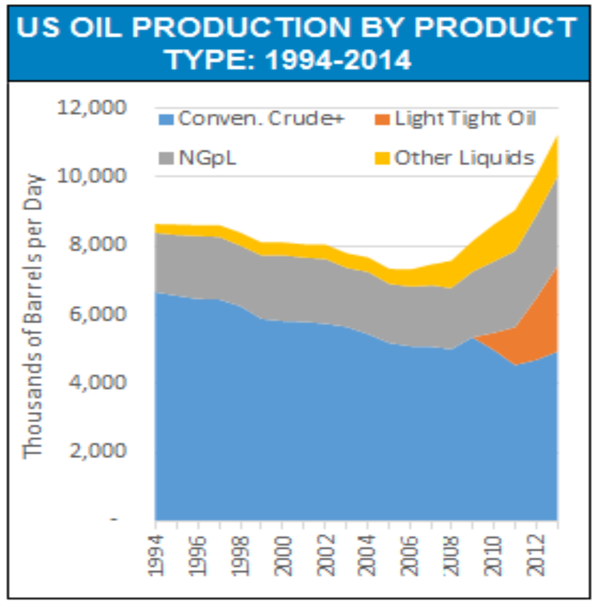
[3] *World Energy Outlook 2014*, IEA, Paris, November 2014 (hereafter WEO 2014). U.S. EIA, *Energy Outlook 2014.*

4 "*We do not set the oil price. The market sets the price […] There are incorrect information and analyses that are circulated from time to time, such as linking petroleum decisions with political objectives. These erroneous analyses will undoubtedly be exposed and proved wrong, helping to return the balance to the market*." HE Minister Ali Al Naimi, interview with the Saudi Press Agency, Riyadh, December 18, 2014.

[5] WEO 2014, 'New Policies' scenario.

[6] To capture what traditional economic modeling does not, I am using the political economic grid put forward by Economic Nobel laureate Douglass North. See notably *Institutions, Institutional Change and Economic Performance*, Cambridge University Press, 1990.

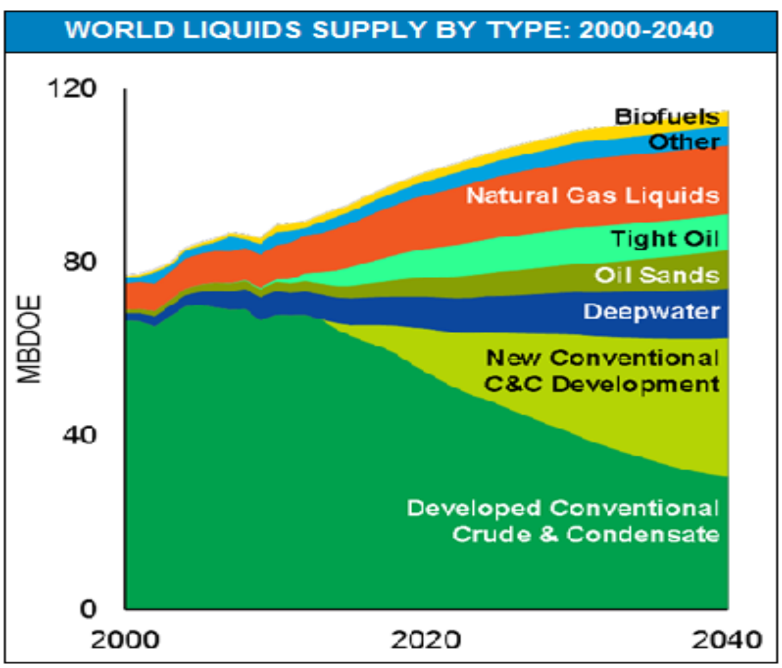
In this Part 1, we'll focus on resources and markets and notably on the changes introduced by US success in monetizing Light Tight Oil (LTO) resources. In Part 2, dated January 2015, we will assess key players through a game-theory perspective, looking at their relative strengths and at strategies they can follow. Against this background, in the Part 3, we'll revisit today's consensus scenario and its key assumption of OPEC producers launching the pendulum back to high prices after a low-price episode that other producers will find punitive. The changing oil industry structure, what it implies for OPEC, and the productivity game that could position US producers of Light Tight Oil more favorably will inform these alternative scenarios.



Source: IEA WEOs 2012 and 2014, EIA, Econvue

The energy elephant and the wise analysts

Influencing the energy sector are a complex mix of economic, technological, political, aspirational and geopolitical forces. Like the wise blind men trying to figure the shape of the proverbial elephant by the touch of their hands, a plethora of experts can lecture on each of these dimensions. But how this disparate lot of perspectives should come together is where preconceived views or fads tend to substitute for the rigorous analysis and mapping tools we need. In Europe, the shape of the elephant is one of *Energy Transition* in which hydrocarbon assets are seen as 'stranded' in a carbon-constrained world. In the US, *Energy Independence* shapes perceptions just as surely as the need for a *Peaceful Rise* through sustained, unhampered economic development shapes Chinese views. In Russia, the 2010 Energy Law to 2030 has made explicit that natural resources are a *tool of foreign policy* to be used in support of Russian grandeur. Meanwhile, for the two billion people who are energy deprived, the



Source: Exxon Mobil "The Outlook for Energy: A View to 2040", Econvue overarching perspective is one of increasing energy supplies of all sorts, whether from gasoline and diesel generators or from off-grid solar.

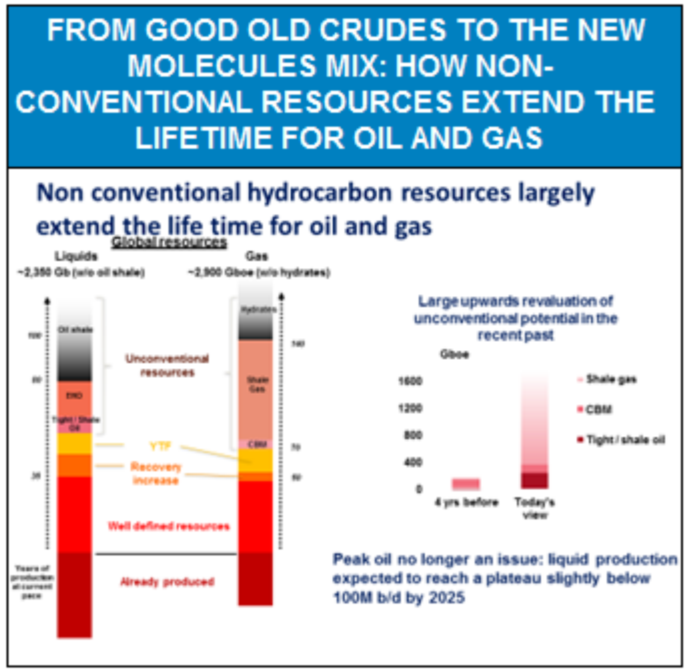
True, in aggregate all forces come together and their outcome can be observed in the balance of demand and supply of 'oil' and other forms of energy. But in today's context, with two major technology revolutions unfolding—in unconventionals and in green energy-- and with geopolitics back at the forefront from Mosul to Moscow, this aggregate supply-demand view obscures as much as it reveals. The map we'll try to work our way to, call it *the energy-system transformation map*, must be a-ideological, informed by facts rather than by aspirations--hence our reluctance to use the term 'transition' that now acts as a blinder for European policy makers. A good starting point will be resources and the naïve question of what we really mean when speaking of 'oil'.

Liquid thinking: the Burgundy touch

What surprised me most when I joined the Shell leadership group in London in the past decade was how seldom my colleagues would speak of 'oil'. 'Liquids', 'crudes' and 'molecules' were the preferred terms, for good reasons.

What upstream oilmen bring from the depth of earth is <u>not</u> some well-defined commodity called 'oil' but cocktails of molecules from which, at each wellhead, one begins by separating 'associated gas' from 'crude'. Associated gas from 'oil' reservoirs, just like 'dry' gas from gas reservoirs, is sold as 'natural gas' only after wellhead processing units have separated methane (CH4) from water, nitrogen, poisonous gas and much, but not all, of heavier hydrocarbons referred to as *Natural Gas Liquids (NGLs)* and consisting of ethane, *Liquid Petroleum Gases (LPG)* like propane and butane and heavier molecules loosely referred to as *condensates.* As for the 'oil' part of the wellhead flow, each crude reflects the long history of the reservoir from which it comes and the way molecules journeyed to it—almost like a Burgundy wine reflects the history, composition and climate of the '*terroir'* from which it is produced, which the wine market recognizes through price differences that can be worth an order of magnitude or more.

Markets set prices not for 'oil' but for some well-defined benchmark crudes based on their specific composition, pollutants and market positioning–West Texas Intermediary (WTI) or Louisiana Light Sweet (LLS) in the US, Brent in the North Sea itself a combination of three different crudes, the Dubai benchmark, the Ural benchmark… And from there, the downstream part of the value chain engages in a finely-tuned ballet of crude selection, transportation, blending and optimized refining and processing based on each refinery's capabilities and cost structure, all this to transform crudes into the most valuable mix of molecules possible in light of market conditions. Forget about catch-all terms: so called 'oil and gas' companies today are really in the *hydrocarbon molecules business*.



Source: Presentation by TOTAL CEO de Margerie at Oil & Money, London, 2013, Econvue

Until recently this molecules-ballet followed a relatively simple script. To start with, oil and gas were relatively distinct, well-delineated industries[7]. Also, most of the liquids produced in the last century were 'crudes' of relatively similar properties although some were lighter than other and some were 'sour' i.e. carried more unwanted sulfur than 'sweet' crudes. Each crude could be priced in reference to the benchmark it competed with most directly (e.g. Brent for many internationally-traded crudes, WTI for US-traded ones…).

Today by contrast an increasing part of US production comes from wells that produce significant quantities both of gas and of liquids and a growing share of liquids differ enough from conventional crudes to be priced in quite distinct markets. Differentials between internationally traded (Brent) and US traded (WTI) crudes but also between natural gas prices (Henry Hub), NGL prices (Mount Belvieu) and oil prices (WTI) play a critical role in the profitability and marketing strategy of US producers.

The most visible consequence of this blurring of the line is the importance that Natural Gas Liquids have assumed in energy projections and in industry profitability. Part of the ethane and NGLs find their way into the 'oil' stream at various stages of the refining process but another part is sold in separate markets at a steep discount to benchmark crude that evolves with specific demand for propane, butane and the like. As could be seen during the fast ramp up of the US 'shale gas' industry, *joint production* of these molecules, and notably the joint production of natural gas and NGLs, makes for more complex economics. Companies for instance have been able to produce natural gas at what were then punitively low Henry Hub prices by recouping much of their costs on the 'liquids' fraction of their production. This however was facilitated by a price differential in favor of NGLs compared to natural gas that has not survived the price collapse[8]. In late 2014 by contrast, before returning to parity in mid-January 2015, US ethane sold at a 20% discount to natural gas, leading producers to 'reject' (i.e. not separate from natural gas flows) a quarter million barrel per day[9]--in this case, turning gas into the trump card for what would otherwise have been part of the 'liquids' production.

[7] In the Soviet Union, an oil company would burn ('flare') all gas it found because it reported to the Ministry for Oil, not the Ministry for Gas, and administrative boundaries trumped value maximization—an echo of which is Gazprom's persisting monopoly over gas export.

[8] The ratio of WTI to Henry Hub gas price (in $/b and $/mbtu) reached 54 in April 2012 and averaged 27 from 2009 to June 24, vs. historic level of 7.5 and energy equivalence of 5.8 mbtu/barrel. Thus liquids had a disproportionate impact on profitability. Since July 2014, this ratio has come down to 15. See Sandy Fielden, RBN Energy, 12.21.14.

[9] Ron Gist, "Where Has All the Ethane Gone? Cheap Ethane Used as Fuel Impacts Balances", RBN Energy, 01/14/15.

Light molecules as the new heavyweight on the block

A key aspect of this changing resources map is that the unconventional 'oil' supply behind the US oil renaissance differs significantly from conventional crude oil not just in how it is produced but in terms of molecules mix. Gradually, policy makers are learning to refer to it as 'Light Tight Oil' (LTO)[10], a hybrid name speaking both of geology and of market outlets. '*Tight'* refers to the fact that these liquids are extracted from rocks in which they are more tightly locked than is the case for a typical crude in its 'conventional' reservoir[11]. The term '*light'* meanwhile refers to the mix of molecules that can be fracked out of such tight rocks—and unsurprisingly, the less porous the rock, the smaller the molecules one may hope to extract from it. This 'light oil' is quite close in molecular composition to NGLs removed from natural gas flow, a mix in which the C2, C3, C4 and C5 molecules are dominant. Unconventional play developers are aware that the term 'oil' sounds better to investors than cryptic terms like NGL, LPG or condensates, nevertheless a lot of what they bring to market is ethane, butane, propane as well as 'natural gasoline' as C5 (pentane) with some C6+ molecules are referred to in the US, a point we'll explore at greater depth in Part 2. Ironically, however, North America is home to two groups of unconventional liquids producers, US LTO producers and Canadian bitumen producers[12] who can blend their unusual liquids into something closer to conventional crude. Like Venezuela, Canada has been propelled to the top of 'oil' reserve holders after the SEC drew the regulatory and accounting implications of technical progress made in monetizing super heavy crudes and authorized companies to book Canadian bitumen as reserves. A thick, sticky, semi-solid form of petroleum from which bacteria have removed lighter compounds over a million years, bitumen is extracted from mined sand. Synthetic crude oil, similar to conventional light crude oil, is then produced in 'upgraders' that break, or 'crack,' the long molecular chains into much smaller molecules, removing carbon and stabilizing them with hydrogen.

US LTO producers are not the only oil producers ending up with NGLs and condensates in lieu of crude. Back in 1990, OPEC shipped 22 mb/d of conventional oil crudes and only 2 mb/d of NGLs, which OPEC did not include under its 'oil' quotas. NGLs production however has grown twice as fast as that of crude and now represent 6 mb/d that come in addition to the 30 mb/d OPEC crude production. The gap will continue to grow and by 2040 the IEA sees OPEC producing around 10 mb/d of NGL (a volume equal to

[10] The term 'shale oil' (unrelated to Canada's 'oil shales') is often used but shale is just one of the mother rocks of low permeability and low porosity in which oil molecules can be locked. Tight oil is therefore a more generic terms. Technologies needed to monetize such deposits are not the conventional ones as facilitation is technically indispensable and horizontal drilling a technical and economic necessity.

[11] Oil contained in rocks with less than 100 millidarcy (md) permeability must be stimulated (1 md=$10^{-15}m^2$).

[12] Canadian oil sands have been mined in the Fort McMurray, Alberta, area since 1967By contrast, *in situ* bitumen production uses steam assisted gravity drainage (SAGD), an Alberta-developed technology in which two parallel horizontal wells are drilled; steam is injected into the upper well, and heated bitumen flows into the lower well. Part of the *in situ* bitumen production is upgraded into high-quality synthetic crude oil, the remainder is diluted with NGLs and shipped by pipeline to U.S. refineries. See *Evolution of Canada's Oil and Gas Industry*, Canadian Centre for Energy Information, 2012.

that of today's Russian oil production!) on top of 36 mb/d to 41 mb/d of crude depending on the scenario. According to the IEA, almost a fifth of global liquid production in the late 2030s will be NGLs.

The 'Peak Oil' perspective: right on 'peak', wrong on 'oil'

> **BP CEO Bob Dudley on the "golden age of innovation"**
>
> *"WE KNOW DEMAND WILL GO UP…40% MORE ENERGY BY 2035 MEANS ONE MORE US AND ONE MORE CHINA TO ADD TO THE WORLD'S GROWING ENERGY CONSUMPTION. BUT WE DON'T NEED TO PANIC. THERE ARE SUFFICIENT RESOURCES IN THE GROUND."* Quoted by Margaret McQuaile and Stuart Elliott, *Platts Energy Economist*, November 2014

How much 'oil' is available in total is an important question in evaluating the consensus scenario we summarized at the onset of our analysis. Today's low prices reflect a shift not just in the market but also in perceptions, away from scarcity. According to the IEA's *World Energy Outlook 2014* of November 2014, it will take only a moderate price increase to $132 (in 2014 prices) by 2040 to accommodate a 19% demand increase in the central 'New Policies' scenario. Prices would rise only to $155 in unchanged ('current') policies scenario in spite of a 32% increase in oil production to 132 mb/d. They would fall to $100 in the aspirational '450ppm' scenario. The U.S. EIA's *Energy Outlook 2014* comes to very similar conclusions[13]. Nevertheless, the mainstream discourse on energy resources remains one in which non-renewable resources are seen as given once and for all. Indeed, until recently, the fact that mankind was going to 'run out of oil' was a powerful argument in favor of energy-transition policies, the last nail in the coffin of the 'old' energy mix. Then almost overnight Peak Oil, in Citi's Chief Energy economist Ed Morse's words, came to be seen, by Americans at least, as "a theory that was buried in North Dakota". This view is not widely shared however in Europe where Peak Oil is only gradually giving way to 'Stranded Oil' as the politically correct way to think, or avoid thinking, about hydrocarbons. Meanwhile, in Russia where unconventional gas is seen as a threat to the country's exports, shale gas and tight oil are often discounted as mere 'bubbles' or even 'Ponzi schemes'—a paradox for a country ranked at the top of LTO reserve holders by the USGS. The map we need should not be hostage to emotional views, reflecting instead on what it takes for 'stuff in the ground' to turn into valuable resources like 'reserves' that companies can book on their balance sheet.

Paradoxically, in the midst of the present US oil boom, peak-oilers could claim having been right by observing that US production of conventional oil in the US did peak and continues on its inexorable decline. ExxonMobil *Energy Outlook* statistics now make clear that the peak in global *conventional* oil production was reached, at 67 mb/d, back in 2005 and that *conventional* production had since then

[13] *"As a result of higher levels of U.S. crude oil production in the High Oil and Gas Resource case, North Sea Brent crude oil prices are lower than in the Reference case: $125 per barrel (2012 dollars) in 2040, compared with $141 per barrel in 2040 in the Reference case. Lower motor gasoline and diesel prices in the transportation sector encourage more consumption. In the Low Oil and Gas Resource case, lower levels of domestic crude oil production result in a slightly higher Brent crude oil price than in the Reference case—$145 per barrel (2012 dollars) in 2040."* U.S. EIA's *Energy Outlook 2014.*

been on a constant decline of 1.2% percent per year. And yet, far from triggering the catastrophic events announced by the Association for the Study of Peak Oil (ASPO), this peak has turned out to be almost a non-event. ASPO's mistake was not about 'peak' but about 'oil' itself. What they believed to be a natural given—how much 'oil' is in the ground—is in fact in large part a human construct. The new LTO reserves making their way into today's US gas tanks were worthless 'molecules in place' that a new wave of innovations transformed into recoverable reserves. The range of 'molecules in place' that could be turned into 'reserves' is larger than static ASPO thinking led them to believe.

Reserves must be seen as a *co-production* of nature and man-made technology. Except for wood and dung that pre-industrial populations could burn on the spot, there is no such thing as a 'natural resource'. Our advanced energy system is fueled by a combination of stuff-in-place and human skills. Terms like 'gas to Liquids' (GTL) or 'cracking' capture the manufacturing element; the evolution underway will not stop there—to the point possibly of 'oil' being someday manufactured from CO2 and water. As John and Beth Mitchell and Valerie Marcel and put it in their report for Chatham House in London: "*The foreseeable problem is not finite resources but the rate at which these very large resources can be converted into reserves for potential production. Reserves of oil and gas have each more than doubled since 1980–faster than the increase in production. Technologies are developing which are creating new reserves of 'unconventional' oil, as they already have for gas*."[14]

Long-term prospects aside, shale gas and tight oil will also peak sometime in the future. Whether this co-creation of additional reserves will proceed fast enough remains an open question but forecasts based on depletion curves for a well identified resource (curves that Shell geologist King Hubbert extrapolated from US oil experience) are not appropriate to a world in which man can change what can be recovered. LTO producers today recover only a few percent of molecules in place as only a subclass of molecules in tight rocks is really harnessed—which means new revolutions could happen. As for Methane Hydrates, which the Japanese JOGMEG project brought to the surface in its first batch in March 2013, they dwarf in size the sum of coal, gas and oil reserves. More on this later.

Peak demand before peak supply?

In its April 2014 annual outlook, the US Energy Information Agency (EIA) presents two scenarios, a Reference Case in which LTO production peaks in 2012 at 4.8 mb/d and a High Oil & Gas Resource case in which LTO production grows to 2035 when it reaches no less than 8.5 mb/d[15], namely about as much as the combined production of Iraq, Kuwait and Nigeria today. Interestingly, the IEA's World Energy Outlook 2014 foresees oil demand peaking before supply stops to grow. In other words, peak demand rather than peak supply will define the mid-century oil market dynamics. In 30 years' time, given some stability in the Middle East, a global demand peak will be reached without 'peak oil' or punishing prices being the constraining force. Already a peak in the world's gasoline demand at 23.5 mb/d is foreseen for early 2030s and a 'peak car' trend is detectable in advanced countries where the latest iPod rather than the fastest, largest car now tend to define social status for younger generations. In the same vein, one may observe that between 2005-2013, despite a 6.9% growth in U.S. population and a 10.4% real output increase, US domestic consumption of finished oil products fell by almost 12% (2.2 mb/d).

[14] John Mitchell with Valérie Marcel and Beth Mitchell, What Next for the Oil and Gas Industry? Royal Institute of International Affairs, Chatham House, October 2012.

[15] EIA, Annual Energy Outlook 2014 and projections to 2040 ('AEO 2014'), pp. IF 10-13.

Three oil value-chains competing for future demand

In Part 1 of this report, we have focused on the nature of the resources over which the 'oil' game is being played, a broader gamut of 'molecules' than the terms 'oil' and 'natural gas' tend to convey. We have made the point that the term 'natural resources' can be misleading as it obscures the man-made dimension of mineral reserves. Yet how reserves are co-produced by man and nature is only one part of the story we need to have in mind when thinking of future demand-supply balance. Who monetizes these resources and towards which set of economic and non-economic objectives is another fundamental consideration we will develop in a forthcoming Part 2.

Dr. Albert Bressand, January 15, 2015
Groningen-Paris-New York.

Albert Bressand is a contributing expert at EconVue (www.econvue.com), an online marketplace for independent economists. You can subscribe to his bi-monthly report at https://www.econvue.com/experts/albert-bressand

Dr. Bressand is a professor of International Strategic Management in Energy at Rijksuniversiteit Groningen (NL) where he heads the multidisciplinary program 'Energy Transition at a Turning Point', and Senior Fellow at the Columbia Center on Sustainable Investment, Columbia Law School - Earth Institute, Columbia University. He is also a member of the faculty of the Columbia Business School's Senior Executive Program and the former head of Royal Dutch Shell's Global Business Environment department in London.