The Outlook for Unconventional Oil & Gas Production

Focus on Tight Oil & Shale Gas Production
Impact on Saudi Arabia

December 2013
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Preface

Over the last year and a half, the rapid increase of tight oil and shale gas production in the US has come to the fore of public consciousness. Numerous articles, TV shows and conferences have discussed the “US Tight Oil and Shale Gas Revolution” and its supposedly radical impact on the energy markets and the position of existing oil producers such as Saudi Arabia.

Following our publication on “Saudi Arabia’s coming oil and fiscal challenge” in July 2011, many clients have asked our opinion on this much-talked-about new source of oil & gas and its impact on the Kingdom’s future standing in the world’s energy markets.

This Report has been prepared to answer that question, and indeed the overarching question of whether and to what degree new technologies may now unlock previously uneconomic oil & gas resources and upend the structure of the world’s energy market.

The analysis of this report was conducted by Mr. Pierre Larroque, a Managing Director in our research department. The Report is not based on proprietary industry data, nor does it pretend to present new facts and innovative studies. Instead, this Report aims at explaining to non-specialists interested in the oil and gas industry (i) the key factors which will drive the evolution of the oil & gas markets, (ii) the technical innovations which led to the “tight oil and shale gas revolution”, (iii) the likely impact of that revolution, and indeed (iv) the likely evolution of the global energy industry in the next 20 to 25 years. It aims to do so by comparing technical and economic data from various reliable sources, and synthesizing them in a coherent and easy-to-understand framework.

For our work, we have relied heavily on a few public domain reports, specifically (i) ExxonMobil’s 2013 “The Outlook for Energy: a View to 2040”, (ii) the International Energy Agency’s “World Energy Outlook 2012”, (iv) the US Energy Information Administration’s “Annual Energy Outlook 2013”, and, for the more detailed analysis of the US tight oil and shale gas plays, (v) the Post Carbon Institute’s 2013 “Drill, Baby, Drill: Can Unconventional Fuels Usher a New Era of Energy Abundance?”.

We have also relied on numerous public domain research papers, industry reports, and specialized and general press articles. All sources are listed in Attachment 8.
Outlook for Unconventional Oil & Gas Production

Definitions

Tight Oil and Shale Oil
Although the terms tight oil and shale oil are often used interchangeably, shale formations are only a subset of all low permeability formations which are the sources of tight oil production and which include sandstones and carbonates, as well as shales.

The US oil and natural gas industry typically refers to tight oil production rather than shale oil production, because it is a more encompassing and accurate term for the geologic formations producing oil at any particular well. The US Energy Information Agency - which provides extensive data on US and international oil & gas production - has adopted this convention.

When discussing estimates of tight oil production and resources in the US, this report thus refers to all, not only shale, tight formations. Conversely however, since the data publicly available to date for oil from international tight formations concerns only shale formations, this report refers to shale oil when discussing the prospects for oil production from such non-US tight formations.

Shale Gas
To date, all data, analyses and commentaries on gas production from tight formations concern shale formations. Hence, this report simply refers to shale gas, when discussing the production and resources expected from the exploitation of tight formations.

Natural Gas
Natural gas is methane - CH₄. It is mainly used in power generation and ammonia and methanol production. It is increasingly exported as Liquefied Natural Gas (LNG) to gas-poor countries.

Sometimes ethane - C₂H₆ - is also described as natural gas and included in discussions on natural gas, in particular in Asia. Ethane is mainly used to manufacture ethylene, the precursor to many petrochemical products.

Natural Gas Liquids (NGLs)
NGLs are the liquid hydrocarbons suspended as particles in gas, under the pressure and temperature conditions of the underground reservoirs.

NGLs are recovered from oil and natural gas wells, and are separated for valuable use in downstream processing facilities. They are ethane, propane (C₃H₈), butane (C₄H₁₀), pentane (C₅H₁₂), and heavier molecules. The heavy NGLs - pentanes and heavier molecules – are called condensates. In the US, they are sometimes also called “natural gasoline”.

When separated in gas processing plants and transported in enough quantities to downstream refineries or petrochemical facilities, NGLs command prices significantly higher than methane. They are a critical factor in the economic attractiveness of shale gas production in the US.

Unconventional Oil & Gas Sources of Energy
The industry does not classify unconventional oil & gas sources in a coherent way. Whilst all observers and institutions consider, analyse and report tight oil, shale gas and oil sands as “unconventional”, some include deep-water and some others extra-heavy oil in their analyses.

In this report, we consider “Unconventional Sources of Oil & Gas” those sources that (i) required the development of new technologies to be extracted, and (ii) should be produced economically at prevailing energy prices. Therefore, we have considered, and discussed, such sources as: (i) tight oil, (ii) shale gas, (iii) oil sands, (iv) deep-water, and (v) extra-heavy crude production. We have in particular ignored kerogen oil (an organic material which has not yet been decomposed into oil but can yield oil upon heating) since, whilst abundant, it will not likely be an economic source of oil in the next 40 years.
Glossary

<table>
<thead>
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<th>Abbreviation</th>
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<tr>
<td>bbl</td>
<td>barrel, used to quantify volumes of crude oil</td>
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<tr>
<td>bpd</td>
<td>barrel per day</td>
</tr>
<tr>
<td>BTU</td>
<td>British Thermal Unit, used to quantify the energy content of gas. A BTU is the amount of energy needed to cool or heat one pound of water by one degree Fahrenheit.</td>
</tr>
<tr>
<td>cf</td>
<td>cubic foot, used to quantify volumes of gas</td>
</tr>
<tr>
<td>cf/d</td>
<td>cubic foot per day</td>
</tr>
<tr>
<td>bcf</td>
<td>billion cubic feet</td>
</tr>
<tr>
<td>tcf</td>
<td>trillion cubic feet</td>
</tr>
<tr>
<td>decline curve</td>
<td>the plot which shows how the rate of oil and gas production from a particular well declines over time</td>
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<tr>
<td>IEA</td>
<td>International Energy Agency. The preeminent international institution which provides data on the world energy situation and prospects. The IEA is funded by 28 countries, which must be members of the OECD. <a href="http://www.iea.org">www.iea.org</a></td>
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<tr>
<td>LNG</td>
<td>Liquefied Natural Gas. Natural gas, predominantly methane, which has been converted to liquid form for ease of storage and export.</td>
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<td>OECD</td>
<td>Organization for Economic Co-operation and Development. Generally considered to include the industrialized countries and to provide consensus economic analyses and forecast. <a href="http://www.oecd.org">www.oecd.org</a></td>
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<tr>
<td>p.a.</td>
<td>per annum, per year</td>
</tr>
<tr>
<td>tonne</td>
<td>a metric tonne, 1,000 kilograms</td>
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<tr>
<td>toe</td>
<td>tonne of oil equivalent, used to quantify, compare and add on a coherent basis the energy content of various sources of energy, such as coal, gas, oil, wind, etc.</td>
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<tr>
<td>US EIA</td>
<td>The US Energy Information Administration. It provides detailed information and analyses on the US and global energy industries. It is reputed to collect and disseminate quality independent data. <a href="http://www.eia.gov">www.eia.gov</a></td>
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Executive Summary

Oil and gas are extracted from underground rocky structures called “reservoirs”, in which small pores and micro-fractures entrap minuscule droplets of oil, together with water and natural gas. When such a reservoir is drilled, and depending upon the rock’s porosity and permeability, the reservoir’s internal pressure pushes the oil to the surface. This goes on, again depending upon the reservoir’s geometry, pressure, porosity, permeability and oil composition, until the outflow peters out, usually after several years.

Since the late XIXth century when oil extraction began, repeated technical advances have allowed us to recover much more than the 10%-15% of the in-situ oil & gas which natural pressure would normally allow. Indeed, the key achievement of the oil & gas industry over the years has been its ability to exploit previously unreachable resources, and to exploit them profitably.

This interplay between (i) physical resources in the deposits, (ii) new technologies which allow their profitable recovery at a given price, and thus (iii) new increases in economically recoverable reserves, is the key topic which this Report addresses.

Indeed, any judgment on the outlook for tight oil and shale gas developments must be based on analyses not only of the physical presence of oil and gas molecules in specific geological formations, but on the comparative economics of extracting these molecules (given likely technological advances) versus the economics of producing oil and gas from other sources, be they conventional or unconventional.

This Report thus first looks at the outlook for the Global Demand for Energy in the medium-/long-term. The consensus from reputable sources is that the world’s energy demand will grow at about 1% p.a. between now and 2040, quite a bit less than the 2.8% p.a. estimated for world GDP growth. This is because most observers assume a significant (35%) decrease in the energy intensity of the world’s economy.

On the basis of this overall growth for the demand of energy, and given the specific regions and sectors which need oil & gas (Asia vs. Europe and America; transport vs. industry, electricity, etc.), most observers estimate that (i) global oil & liquids demand will grow from 4.5 billion toe in 2010 to 5.6 billion toe in 2040, and (ii) global gas demand will grow from 2.9 billion toe in 2010 to 4.7 billion toe in 2040.

The growth in oil demand will be driven mainly by global increases in transportation needs. The growth in gas demand will be driven mainly by very large increases in electricity production.

Tight Oil

On the supply side, most observers agree that production of oil from conventional sources will decline, while that from new unconventional sources, including tight oil, will increase rapidly. Most also foresee a rapid growth in NGLs production from tight oil and shale gas wells.

We agree that oil production from deep-water fields will grow rapidly to compensate the decline in conventional oil production (as well as, to a lesser degree, production from oil sands and from extra-heavy-oil fields).

We are however not convinced that the production of tight oil in the US and shale oil elsewhere will increase as much as most observers believe.
This is because, since tight formations are by definition impermeable, the migration of oil towards the well, even after hydraulic fracturing, is limited and wells are much less productive than in conventional formations with permeable and porous rock. In fact, the decline curves of tight oil wells are steep, often between 81% and 90% in the first 24 months, which means that new expensive wells must continually be drilled to maintain production, let alone expand it.

**Outlook for tight oil production in the US.** As much as 80% of the US tight oil production comes from only 2 plays, the Bakken in North Dakota and Montana and the Eagle Ford in South Texas. The Bakken has by now been quite exploited, with most of the “sweet spots” likely past peak production. Eagle Ford is still a young play with significant drilling activity and thus production upside.

From our detailed review of reports on fields-by-fields drilling and well productivity and other industry data, we believe that US tight oil production may reach its maximum in 2017 and decline rapidly thereafter. We note however that many observers affirm that, with continued technological advances, US tight oil basins will yield a much higher and longer production.

**Outlook for oil production from international shale formations.** We also are less optimistic than most commentators for production from these formations. This is both because we believe that other countries do not benefit from the US’ uniquely favorable “above ground” factors, and also because we are not aware that the target geological formations are as well understood as those in North America. The exception may be the Vaca Muerta basin in Neuquen, an already important oil-producing region of Argentina. This however is unlikely to account for the 4-5 million bpd which most observers assume for tight oil production in 2040.

**Shale Gas**

Gas supplies are expected to increase by about 65% between 2010 and 2040 to meet global gas demand. The large majority of the increase in expected to come from Eurasia, the Middle East and Asia. Unconventional gas supplies are set to play a central role in this increased gas production, as shale gas is expected by most observers to account for about half of the forecast increase in long-term gas production.

Yet, as for tight oil, we are not convinced that shale gas production will actually grow as rapidly as most observers surmise.

**Outlook for shale gas production in the US.** Shale gas production has increased rapidly in the US and now accounts for about 40% of US natural gas production (this jumps to above 60% if one adds the gas produced from tight oil wells).

As for tight oil formations, well decline rates are very steep, ranging from 79% to 95% after 36 months which implies that about 50% of production must be replaced annually to maintain production.

The rapid supply increase has depressed US natural gas prices to a point where drilling shale wells is uneconomic, except when they produce meaningful volumes of NGLs. Thus, once the inventory of drilled-but-not-yet-in-production wells is worked off, shale gas production will rapidly decline for dry plays.

The exceptions are the Marcellus and Eagle Ford plays which produce significant quantities of NGLs. Both Marcellus and Eagle Ford are large basins which still offer substantial undrilled a-priori-productive zones and already possess adequate
infrastructure to treat the gas and transport it to consumption centers. Their continued sustained pace of drilling and increased production will likely keep downwards pressure on gas prices and will constrain the activities in other plays.

Thus, whilst we agree that shale gas production from Marcellus and Eagle Ford will keep increasing, we doubt that, in overall, US shale gas production will keep increasing as rapidly, and reach and remain at levels as high, as most observers assume including the IEA and the US EIA.

Outlook for international shale gas. Most commentators have reported for a bright outlook for shale gas production outside the US. The US EIA in particular significantly increased this May its estimates of technically recoverable gas resources from international shale formations.

Our review of the bases for these estimates lead us however to doubt that international shale gas production is as promising as advertised. First, as the US EIA itself points out, the geology of the shale basins is not well understood yet, and the productivity of shale wells cannot be forecast. And second, most importantly, “above ground” factors will likely be much less favorable for international basins than in the US.

Indeed, recent reports have cast doubts on the feasibility of extracting shale gas economically in China. Whilst Argentina and Australia reportedly offer good geological prospects and a-priori favorable “above ground” factors, any production there is likely years away. Above ground factors in Mexico, England and France seem to preclude the exploitation of shale formations for the foreseeable future. Initial production tests in Poland were inconclusive, in particular as drilling costs may be too high to justify developing the fields.

We thus doubt that international shale gas production will grow as rapidly as most observers foresee.

Other Unconventional Sources of Oil & Gas

In addition to tight oil, there are three major other unconventional sources of oil which will impact the world’s energy industry in the next 30 years: deep-water reservoirs, oil sands and extra heavy oil deposits.

Deep-water fields. We believe that, in spite of their requirements for massive investments, deep-water fields will become an increasingly important source of oil in the short-/medium-term. Most large international companies expect deep-water oil to provide a significant portion of their liquids production for years to come.

Oil sands. The mining of oil sands or bitumen from Alberta (Canada) has developed into a large industry over the last 30 years, contributing about 14% of the US oil imports in 2011. The mining of these oil sands is expensive though and the output is a very heavy oil which needs to be diluted with NGLs or upgraded into lighter crude to be transported to and processed by US refineries. Depending upon the evolution of oil prices (including the light to heavy crude differential), and if adequate infrastructure is built, oil sands can over the long-term undoubtedly help meet global energy demand.

Extra heavy oil. A major portion of the world’s recoverable oil resources is in extra heavy deposits. Oil from these deposits is too viscous to extract by simple conventional technology. The industry has already succeeded in improving the recoveries, in particular with steam injection, so that, in some of these fields,
production is economic at current prices. Significant efforts are under way to develop more efficient and economic ways to extract the oil from such deposits, and depending upon the evolution of oil prices, we expect extra heavy oil eventually to contribute a significant portion of global oil supplies.

Tight Oil, Shale Gas and the Long-Term Global Energy Outlook

**Tight Oil.** Even though we doubt that tight and shale oil production will grow as most commentators forecast, we believe that the industry will reasonably comfortably produce enough liquids to meet long-term demand, and this for two reasons:

First, tight oil production represents only about 3% of total liquids supply, so a smaller production of tight oil will not seriously affect global oil markets.

And, second, deep-water production may actually be larger than now assumed. Further, additional supplies will likely be forthcoming from extra-heavy oil and oil sands if oil prices rise above their current levels.

**Shale Gas.** Even though we doubt that shale gas production will keep growing as much and as rapidly as most commentators forecast, we also believe that the industry will reasonably comfortably produce enough gas to meet long-term demand.

First, there will likely be enough conventional sources of gas which can be developed in Africa, Eurasia and the Middle East to compensate for a shortfall in shale gas production.

And, second, were a long-term shortage of natural gas to develop, gas prices will increase and more US shale deposits will be exploited. In that respect, the emergence of a deeper international LNG/gas trade will increase the rationale for developing hitherto “stranded” gas resources, in the US and elsewhere.

Impact on Saudi Arabia

**Tight Oil.** Since we doubt that tight oil production will grow as much as most commentators surmise, and since we believe that tight oil production will keep representing only about 3% of total liquids supply, we do not believe that the growth in oil production from tight rock formations in the US, or from shale formations elsewhere, will materially affect Saudi Arabia’s long-term position in the oil industry.

We view the production of tight oil in the US as mainly impacting Saudi Arabia through the narrowing of the price differential between heavy and light crudes. That narrowing may force a restructuring of downstream global refining activities, in particular in Europe, but should not affect Saudi Arabia’s refining complexes.

We thus remain of the opinion that **the key factor** that will impact Saudi Arabia’s long-term position in the world’s energy industry is **the high, and growing, internal demand.** As we have previously opined, we believe that that high internal demand, spurred by low internal energy prices, will not only distort internal economic decisions, but will also, in the long-term, crowd out and reduce the income from Saudi Arabia’s oil exports.

**Shale Gas.** We doubt that the production of shale gas in the US and elsewhere will increase as much as most observers surmise. Yet, we believe that the large production of cheap (by-product) NGLs from tight oil and shale gas formations will have a significant impact on the world’s petrochemical industry.
We thus see the main impact of the US shale gas and cheap NGL production on Saudi Arabia as (i) reducing the comparative profitability of Saudi’s existing petrochemical complexes, and (ii) inducing Saudi petrochemical firms to consider expanding their capacity in the US to profit from abundant, cheap yet valuable, feedstock.
ملخص تنفيذي

يحضر النفط والغاز من التكوينات الصخرية تحت سطح الأرض والتي تسمى "خزانات" وتنميز بوجود مساح صغيرة وكسر دقيقة في النقطة الصخرية جدًا مع الماء والغاز الطبيعي. وعندما يتم حفر مثل ذلك الخزان - واعتمادًا على مساحة الصخور والمفاجأ، يؤدي الضغط الداخلي للغاز إلى دفع النفط باتجاه السطح.

تتواصل هذه العملية، ببناء على هندسة الخزان ومستوى الضغط فيه ومسامته ونفاذه وتركيبة النفط، إلى أن يتوفر الانسباب كليًا والذي عادة ما يكون بعد سنوات عديدة.

وقد أتاح التطورات التقنية، التي تواصلا منذ بداية استخراج النفط في نهاية القرن التاسع عشر، استخلاص كميات من النفط والغاز أكثر من نسبة 10 إلى 15 باليونانية، التي تقوم ضغط الطبيعي، في الواقع، كانت الإíchادات الرئيسية التي حققتها صناعة النفط والغاز عبر السنوات هي قدرتها على استغلال موارد نفطية لم يكن بالإمكان الوصول إليها سابقاً واستخراجها بطريقة مربحة.

إن القصة الرئيسية التي يبحثها هذا التقرير في التفاعل بين ثلاثة عوامل: (1) الطواير الطبيعية الموجودة في الحقول و (2) الطواير الطبيعية الموجودة في العديدات الجدديدة التي تنتج استخراج تلك الموارد بطريقة مربحة عند سعر معين و (3) والزيادات الجديدة في الاحتياطيات التي يمكن استغلالها بطريقة اقتصادية.

في الواقع، يجب أن يُحكم على مستقبل التطورات في إنتاج النفط الحجري والغاز الصخري على إجراء تحليلات ليس فقط للخروج الفعلي لزيادة النفط والغاز في التكوينات الجيولوجية المعيشة، بل كذلك تحليل الفاعلية الاقتصادية لاستخلاص تلك الزيادات (مع الوضع في الاعتبار التطورات الفنية المحتملة) مقابل اقتصاديات إنتاج النفط والغاز من مصادر أخرى تقليدية كانت أو غير تقليدية.

لذلك، فإن هذا التقرير يبحث في مستقبل الطلب العالمي على الطاقة في المدين المتوسط والبعيد. في هذا الجانب، تجمال مصادر موثوقة أن الطلب العالمي على الطاقة سينمو بنسبة 1% سنويًا في المتوسط خلال الفترة من الآن وحتى عام 2040.

وهي نسبة نقل كثيرة عن متوسط النمو السنوي للإنتاج البشري العالمي الذي يتوقع أن يكون عند 2.8% سنويًا خلال نفس الفترة. وتعد تلك التقديرات إلى افتراض معظم المراكبين حديث تراجع كبير (نسبة 35 بالمائة) في كفاءة استخدام الطاقة في الاقتصاد العالمي.

وبناء على معدل النمو الكلي للطلب العالمي على الطاقة، وبالنسبة إلى المناطق والقطاعات المعيشة التي تحتاج إلى النفط والغاز (أسيا مقابل أوروبا وأمريكا: الناقل مفاعل الصناعة والكبار)، يوجد معظم المراكبين الآتي: (1) نمو الطلب العالمي على النفط والغاز والموارد من 4.5 مليار طن مكافئ نفطي عام 2010 إلى 5.6 مليار طن نفطي عام 2040 و (2) نمو الطلب العالمي على الغاز من 2.9 مليار طن مكافئ نفطي عام 2010 إلى 4.7 مليار طن مكافئ نفطي عام 2040.

وسيأتي النمو في الطلب على النفط بصورة أساسية من زيادة الخزانات في احتياجات النقل، بينما يأتي النمو في الطلب على الغاز بصورة أساسية من الزيادات الكبيرة جداً في إنتاج الكهراء.
النفط الحجري

من ناحية العرض، يتفق معظم المراقبين على أن إنتاج النفط من الموارد التقليدية سيتراجع، مقابل زيادة كبيرة في إنتاج النفط من الموارد غير التقليدية، بما في ذلك النفط الحجري. كذلك يتوقع معظم زادة سريعة في إنتاج سوائل الغاز الطبيعي من أبار النفط الحجري والغاز الصخري.

توقعات إنتاج النفط الحجري في الولايات المتحدة: يتأتي 80 بالمائة من إنتاج النفط الحجري في الولاية المتحدة من حقين فقط. هما حقل داكونا ومونا وحقل إيجلي فورد في جنوب تكساس. يمكن القول أنه حتى الآن أستغل معظم حقل باكن. حيث بلغت معظم "المناطق المناسبة" فيه إنتاجها الأقصى، أما حقل إيجلي فورد فلا يزال في سنواته الأولى وهما هناك أعمال حفر ضخمة تتم فيه وذلك يتوقع أن يزيد إنتاجه.

وبناء على دراستنا المفصلة لتقارير أعمال الحفر وإنتاج الآبار في كل حقن من الحقن وكذلك اطلاعنا على البيانات المنشورة من قبل الجهات المختصة في صناعة النفط، فإننا نعتقد أن إنتاج النفط الحجري في الولايات المتحدة سيعبر ذروته عام 2017 ثم يرتفع بسرعة بعد ذلك. ونلاحظ أن هناك الكثير من المراقبين يؤكدون أن أمواج النفط الحجري الأمريكية ستنتج كميات أكبر وستدوم لفترة أطول بفضل تواصل التطورات التقنية.

توقعات إنتاج النفط من التكنولوجيات الصخرية في المناطق الأخرى من العالم: كذلك، نحن أقل نفاقًا من معظم المراقبين إزاء إنتاج النفط من تلك التكنولوجيات الصخرية. ويرجع ذلك لسبيكة: نعتقد أنه لا تتوقف للدول الأخرى الظروف الاستثنائية المواتية التي تتوفر للولايات المتحدة والتي استفادت منها كثيرًا وتتمثل عوامل البنية التحتية المادية والبشرية والتفوق التقني، وبناء تنظيمية ومالية ماسة وبديل معيشي للأثر البيئي لتكنولوجيا التكرير وتعزز هذه العوامل مجتمعة أشخاصًا في صناعة النفط بالعوامل "فوق سطح الأرض". كما أننا نعلم ما إذا كان هناك فين دقائق لتكنولوجيات الجيولوجية تلك المناطق المستفيدة مثل تكنولوجيات في أمريكا الشمالية. الاستثناء الوحيد ربما يكون حوض فاكر موريسا في تكساس، وهي منطقة
في الأرجنتين يجري فيها إنتاج النفط منذ فترة. لذا، فإن هذا الوضع لن يدعم على الأرجح التقديرات التي يضعها معظم المراقبين والتي تتوقع أن يراجع إنتاج النفط الحجري بين 4 إلى 5 مليون برملي يومياً عام 2040.

**غاز الصخري**

يتوقع أن تزداد إمدادات الغاز بنسبة 65 بالمائة بين عام 2010 و2040 لتلبية الطلب العالمي على الغاز، وتستغرق أن تأتي الغازية العائمة من الزراعة من أوراسيا والشرق الأوسط وأسيا. وتقاعد أن إمدادات الغاز غير التقليدية مهأة للعب دور محوري في هذه الزيادة، حيث يتوقع معظم المراقبين أن يشكل الغاز الصخري نصف الزيادة المتوقعة في إنتاج الغاز على المدى البعيد.

كذلك، وكما هو الحال بالنسبة للنفط الحجري، لم تعد أداة كافية تدعم الاعتقاد السائد بأن إنتاج الغاز الصخري ستنمو فعلاً بالسرعة التي يفترضها معظم المراقبين.

**توقعات إنتاج الغاز الصخري في الولايات المتحدة**

هيئة إنتاج الغاز الصخري بسرعة في الولايات المتحدة وحالياً، يتمثل هذه النسبة في 60 بالمائة إذا أضافنا الغاز المنتج من أبار النفط الحجري.

كما في حالة تكوينات النفط الحجري، تعتبر معدلات تنافس إنتاج الأبار حاداً جداً وتمتد بين 79 بالمائة و95 بالمائة بعد 36 شهراً، مما يستخدم إنتاج نحو 50 بالمائة من الإنتاج سنوياً للمحافظة على مستوى إنتاجي ثابت.

أخذ الزيادة السريعة في إمدادات الغاز إلى تراجع أسعار الغاز الطبيعي الأمريكي إلى مستوى أصبع فيه أبغر صخري غير مجدي اقتصادياً، إلا في حالة إنتاج تلك الأبار لكميات كبيرة من سوائل الغاز الطبيعي. لذلك، فإنه بمجرد نفاذ مخزون الأبار التي تم حفظها ولكن لم يبدأ الإنتاج فيها بعد، ستراعج إنتاج الغاز الصخري بسرعة في الجوفان الجاف.

في نفس الوقت يجري تحلي مارسيليوس وإيجيل فورد الذين ينتمون جماعات كبيرة من سوائل الغاز الطبيعي، وهم حوضان كبيران يزالا بهما مساحة وعامة لم تتحف بعد، كما أنهم يجدان بنيات عودية تقوم بمساعدة في التدخل في مراكز الاستدلال. لكن الاستمرار في الحفر وزيادة الإنتاج بوتيرة عالية سيؤدي إلى استمرار الضغوط على أسعار الغاز وهو الأمر الذي يؤدي إلى إعادة النشاط في الأحوال الأخرى.

وهكذا، فرغم من أينفجتر على الرؤى القائل بأن إنتاج الغاز الصخري من حقل مارسيليوس وإيجيل فورد سيفتح في إمدادات لكننا يمكن أن ننظر في أن يظل إنتاج الغاز الصخري الأمريكي ككل يتزايد بالترابط التي يفتقدها معظم المراقبين حالياً، بما في ذلك وكالة الطاقة الدولية وإدارة معلومات الطاقة الأمريكية.

**توقعات إنتاج الغاز الصخري حول العالم**

وضع معظم المراقبين صورة زاهية لمستقبل إنتاج الغاز الصخري خارج الولايات المتحدة، حيث رفعت إدارة معلومات الطاقة الأمريكية في مايو الماضي بدرجة كبيرة توقعها لما وراء الغاز القابل للاستخراج تقنياً من التكوينات الصخرية حول العالم.

**December 2013**
ولىً اطخػساطىا للؤطع التي بىِذ غلحها جلً الخلدًساث ًلىدها للشً في أن ًىمى ئهخاح الغاش الصخسي الػالمي بخلً الىجيرة. أولاً، وهما حشير ئدازة مػلىماث الؼاكت الأمسٍىُت هفظها، ختى الآن لِع هىان فهم وامل للخصائص الجُىلىحُت للؤخىاض الصخسٍت، ئطافت ئلى اطخدالت جلدًس ئهخاحُت آباز الغاش بصىزة دكُلت. وزاهُاً، وهى طبب أهثر أهمُت، طخيىن الػىامل "فىق طؼذ الأزض" أكل دغماً لقلىٌ الغاش في االإىاػم الأخسي مً الػالم ملازهت بمظخىي الدغم الري ججده القلىٌ الأمسٍىُت.

في القلُلت، أزازث جلازٍس خدًثت الشيىن خىٌ الجدوي الاكخصادًت لاطخخساج الغاش الصخسي في الصين. وغلى السغم مً وسح جلازٍس غً جىفس ئمياهُاث حُىلىحُت حُدة في الأزحىخين وأطترالُا ئطافت ئلى جمخؼ هاجين الدولخين بػىامل ئًجابُت "فىق طؼذ الأزض"، لىً مً غير االإخىكؼ كدوم أي ئهخاج مً هىان كبل مسوز غدة طىىاث. هرلً، ًبدو أن الػىامل "فىق طؼذ الأزض" حػُم اط
خلاٌ الـ
31 غاماً اللادمت: الخصاهاث في االإُاه الػمُلت
والسماٌ الىفؼُت وزطىبُاث الىفؽ الثلُل.

جالُاً جبرٌ الىثير مً الجهىد لخؼىٍس ػسق أهثر فػالُت واكخصادًت لاطخخساج الىفؽ مً مثل جلً السطىبُاث، وهخىكؼ في نهاًت الأمس، بىاءً غلى مظاز أطػاز الىفؽ، أن ٌظاهم الىفؽ الثلُل بيظبت هبيرة مً مصادر أخرى غير التقليدية لإنتاج النفط والغاز

المصادر الأخزى غير التقليدية لإنتاج النفط والغاز

بالإضافة إلى النفط الحجري، هناك ثلاثة مصادر أخرى رئيسية غير تقليدية للنفط ستؤثر على صناعة الطاقة في العالم خلال الـ 30 عاماً القادمة: الخزانات في المياه العميقة والرمال النفطية ورسوبيات النفط الثقيل.

حقول المياه العميقة: تعتبر أن حقول المياه العميقة ستصبح، رغم حاجتها لاستثمارات ضخمة، مصدرًا هاماً للنفط في السنوات القادمة.

الرمال النفطية: تطور التنقب عن الرمال النفطية أو البترول من أستراليا (كندا) إلى صناعة ضخمة خلال الـ 30 عاماً الماضية. حيث شكل نسبة 14 بالمائة من إمدادات النفط الأمريكية عام 2011. يعتبر استخراج النفط من تلك الرياح النفطية مكلف جداً. كما أنه من النوع القياسي الذي يطلب تخفيفه بوسائل الغاز الطبيقي أو ترشيحه إلى خام أخف ليتم تلته إلى مصانع التكرير الأمريكية للعمل. ويمكن للرمال النفطية أن تساهم على مدى الطويل في تلبية بعض الطلب العالمي على الطاقة، وذلك اعتباراً على مسار أسعار النفط (بما في ذلك فرق السعر بين الخامات الخفيفة والثقيلة). وكذلك تشييد

بنيات تحتية كافية.

النفط الثقيل: نسبة كبيرة من المراد النفطية حول العالم القابلة للاستخراج من الرياح العمقية هي رسوبيات تحتوي على
النفط الثقيل. ويصف النفط المستخرج من تلك الرسوبيات بأنه لزج، حيث يصعب استخراجه بالتقنيات التقليدية العامة. نجحت صناعة النفط في عمليات الرياح، خاصة باستخدام تقنية حقن البخار، وذلك أصد الإنتاج في بعض تلك الحقول إقتصادياً بالأسعار الجاللة. حالياً تبذل الكثير من الجهود لتطوير طرق أكثر فعالية واقتصادية لاستخراج النفط من مثل تلك الرسوبيات، وتوقع في نهاية الأمر، بناء على مسار أسعار النفط، أن يساهم النفط الثقيل بنسبة كبيرة من

إمدادات النفط العالمية.

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Outlook for Unconventional Oil & Gas Production

December 2013
الت رسول المحترف بين النفط الصخري والغاز الصخري، مستقبل الطاقة العالمية في المدى البعيد

النفط الصخري: رغم شكوكنا إزاء نمو إنتاج النفط الصخري والغاز الصخري بالمعدل الذي يتوقعه معظم المراقبين، لكننا نعتقد أن صناعة النفط مستقلة بسهولة وبطريقة معقولة إنتاج سوائل كافية تلبيةطلب في المدى البعيد وذلك لسبب.

ولكن، ربما يكون الإنتاج الفعلي من المياه العميقة أكبر مما هو مفترض الآن. إضافة إلى ذلك، ربما تأتي إمدادات إضافية من النفط النفطي والнем الوافق في حال ارتفاع أسعار النفط بدرجة كبيرة عن مستوياتها الحالية.

الغاز الصخري: رغم شكوكنا بأن نمو إنتاج الغاز الصخري يمكنه بالمعدل الذي يتوقعه معظم المراقبين، لكننا نعتقد أن الصناعة مستقلة بسهولة وبطريقة معقولة إنتاج غاز كافياً تلبيةطلب في المدى البعيد وذلك لسببين.

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وتأثر على المملكة العربية السعودية

النفط الصخري: وحيث أشار لنا ذلك في أن نمو إنتاج النفط الصخري بالẋسيرة التي يليها معظم المراقبين، وبناءً على نقدنا بـ إنتاج النفط الصخري سيبقى فقط 3 بالمائة من إجمالي إمدادات السوائل، فلا نعتقد بأن النمو في إنتاج النفط من التكوينات الصخرية المعدنية في الولايات المتحدة أو من التكوينات الصخرية في المناطق الأخرى من العالم، سيؤثر بشكل كبير على موقع المملكة الراسخ في صناعة النفط والذي ظلت تحتله منذ زمن طويل.

ولكننا ننظر إلى إنتاج النفط الصخري في الولايات المتحدة من حيث تأثيره بصورة أساسية على السعودية من خلال تقليص فرق السعر بين الخامان الهائلة والخلقية. هذا التقليص ربما يؤدي إلى فرض إعادة هيئة في أنشطة التكرير العالمية، وخاصة في أوروبا. لكنه لن يؤثر على معامل التكرير في المملكة.
وعليه، فإننا نؤمن بأن العامل الرئيسي الذي سيؤثر على الوضع الرأسي للملكة في صناعة الطاقة العالمية هو ارتفاع الطلب المحلي. وكما ذكرنا في تقرير سابق، فإننا نعتقد أن الطلبة المحلي المرتفع، الذي يواصل ارتفاعه نتيجة الانخفاض الكبير في أسعار الطاقة المحلية. لن يشوه فقط القرارات الاقتصادية المحلية، بل سيؤدي كذلك إلى تراجع دخل الملكة من الصادرات النفطية.

الغاز الصخري: نشك في أن ينمو إنتاج الغاز الصخري في الولايات المتحدة وغيرها بالقوة التي يطلبها معظم المراقبين. لكن، نعتقد أن الإنتاج الكبير من سوائل الغاز الطبيعي الرخيص المستخلصة (كمنتن ناتو) من تكوينات النفط الحجري والغاز الصخري سيكون له تأثير كبير على صناعة البترول كفاوتات في العالم.

لذا، فإننا نرى أن التأثير الرئيسي لإنتاج الغاز الصخري وسوائل الغاز الطبيعي الرخيص في الولايات المتحدة على المملكة العربية السعودية سيكون من ناحيتين: (1) تقليل الربحية العالمية نسبيًّا لمصاعد البترول كفاوتات القائمة حالياً في المملكة و (2) حيث شركات البترول كفاوتات السعودية للنظر في زيادة طاقاتها الإنتاجية في الولايات المتحدة للتقدم من توفر المواد الأولية الرخيصية مرفعة القيمة.
**THE OUTLOOK FOR UNCONVENTIONAL OIL & GAS PRODUCTION**

**FOCUS ON TIGHT OIL AND SHALE GAS PRODUCTION**

**IMPACT ON SAUDI ARABIA**

I. **THE BASICS OF OIL PRODUCTION**

Oil is not found in underground lakes. Oil is found in rocky structures called “reservoirs” which have small pores and micro-fractures which entrap minuscule droplets of oil, together with water and natural gas.

Nature created these “reservoirs” over millions of years, when huge deposits of vegetation and dead microorganisms piled up at the bottom of ancient seas, decomposed and were buried under successive layers of rock. High temperatures and pressures slowly transformed the organic sediments into today’s oil and gas.

These “fossil fuels” soak the porous rock underground, and, when such a reservoir is drilled, and depending upon the rock’s porosity and permeability, the reservoir’s internal pressure pushes the oil to the surface (along with mud and stones). This goes on, again depending upon the reservoir’s geometry, pressure, porosity, permeability and oil composition, until the outflow peters out, usually after several years.

This initial, or primary, stage of recovery usually yields between 10 and 15 percent of the oil in place. From then on, recovery must be assisted.

Obviously, the effectiveness of additional recovery techniques depends upon many factors including the formation’s geology, its permeability and how liquid the oil is (as opposed to being a heavy, viscous, molasses-like substance).

To help the remaining oil seep through the pores in the rock and come out of the wells, operators usually inject natural gas and water into the reservoir, in what is called secondary recovery. This may allow for the recovery of 20 to 40 percent of the oil in place.

Stronger actions such as injecting special chemicals, heat or even microbes to thin out the remaining oil and facilitate its moving through the rock, are called tertiary recovery. Such harsher treatments may allow for the recovery up to 60% of the oil in place.

The well’s production over time is logged in a “decline curve” which reflects how much and how fast oil can be extracted from the reservoir. Large productive reservoirs have slowly declining production curves for many years, meaning that they produce large stable quantities of oil for 5-6 years or more; small, usually shallow, reservoirs are exploited with wells which have steep decline curves meaning that they stop producing in economic quantities in 3-5 years.

In the last 20 years, in large part as a response to increasing oil prices, several important technical developments have significantly increased man’s ability to discover, understand and recover previously unreachable or uneconomic oil and gas deposits.
In parallel, advances in the downstream treatment of heavier and heavier crudes have allowed the profitable extraction and treatment of previously unattractive hydrocarbon rich deposits, even the mining of bitumen or oil sands.

### Three Stages of Oil Recovery

**Primary:** Recovery: up to 15%
- Reservoir’s internal pressure pushes oil out

**Secondary:** Recovery: 20% to 40%
- Water or natural gas push more of the oil out

**Tertiary:** Recovery: up to 60%
- Chemicals, heat or microbes thin out the remaining oil

*Source:* “Squeezing more oil from the ground” – Scientific American, October 2009

This interplay between (i) physical resources in the deposits, (ii) new technologies which allow their profitable recovery at a given price, and thus (iii) new increases in economically recoverable reserves, is the key topic which this Report addresses.

This Report’s Section II provides definitions for the words “resources” and “reserves”, which the natural resources industries use to describe mineral and oil & gas occurrences and the potential for their extraction. This is to allow for clarity and consistency when considering the various arguments and forecast which this Report subsequently puts forward. Section III summarizes the major technological developments which have shaped the oil & gas industry since its inception, and more particularly those which have recently allowed for the rapid development of unconventional sources of oil & gas.

Section IV presents the long-term global demand for all energies, as forecast by most industry players and institutions. Sections V discusses the resulting global demand which they forecast specifically for oil & gas, and Section VI the sources of supply which will satisfy that demand. This frames the question which the Report attempts to answer: to what extent will the production from unconventional sources of oil & gas, specifically tight oil & shale gas, revolutionize and restructure the oil & gas industry?
Section VII discusses the prospects for tight oil in the US. Section VIII comments on (i) the unique “above ground” factors which have enabled the rapid growth of tight oil production in the US, and, by contrast, (ii) the likely less rapid growth of tight oil production in other countries. Section IX examines the prospects for shale gas production in the US and globally.

Section X presents how we see the growth in US and international tight oil and shale gas production impacting the global downstream refining and petrochemical industries.

Section XI discusses the other unconventional sources of oil & gas (deep-water, oil sands and extra heavy oil) and how these are likely to impact the global oil & gas industry.

Finally, in view of the analyses presented above, Section XII presents our views on the likely developments of tight oil and shale gas in the US and globally, and Section XIII summarizes the impact we see from these developments on the Saudi oil & gas sector.
II. ENERGY PRICE, TECHNOLOGY AND THE EVOLUTION OF OIL & GAS RESERVES

The definition and estimation of “Reserves” for mineral and oil & gas deposits have always been a topic of interesting debates in scientific, industrial and economic circles.

Indeed, forecast declines in the availability of natural resources have historically pushed some economists and social commentators to doubt the sustainability of long-term economic growth. In large part, this is because of the confusion between (i) the physical existence / presence of metal or hydrocarbon molecules in a geologic formation, and (ii) that portion of those molecules which can be economically recovered.

A. Definition of Reserves for the Mining Industry

Over the years, mainly because the extraction of minerals from identified deposits is technically more predictable than the recovery of oil & gas from identified reservoirs, the mining industry - i.e. the industry which extracts minerals from the ground - has evolved a very precise nomenclature to define and to describe mineral occurrences:

1. **Mineral resources**: this is a geological / physical concept. It relates to the actual presence of minerals in the deposit.

2. **Ore reserves**: this is an economic value concept. It relates to the (technical, financial and legal) capability to extract minerals profitably from the deposit.

For various levels of confidence in understanding the deposit and its mineability, the mining industry thus uses precisely-defined terms such as “Proven and Probable Reserves” and “Measured and Indicated Resources”. The precision, clarity and universality of this nomenclature, and the clear distinction between the physical presence of interesting minerals and the confidence to recover them at a profit, have spurred the development of the healthy capital markets and sophisticated investor base which now routinely fund promising mining exploration ventures across countries.

B. Definition of Reserves for the Oil & Gas Industry

On the other hand, the oil & gas industry - i.e. the industry which extracts oil & gas from the ground - uses less precise terms when it describes (i) the physical presence of hydrocarbons in various rock formations, and (ii) its ability to recover such hydrocarbons economically from these formations. Indeed, whilst some progress has been made to establish a harmonized system of defining and classifying oil resources and reserves, these are in practice still measured and reported differently by country and jurisdiction.

In this report, we will use the terminology used in the IEA reports:

1. **Proven Reserves**: the discovered volumes having a 90% probability to be extracted profitably.

2. **Remaining Recoverable Resources**: these are the proven reserves, reserves growth (the projected increase in reserves in known fields) and as-yet-undiscovered resources that are judged likely to be ultimately producible using current technology.

From the above, one immediately sees how four critical factors impact our understanding and confidence of how much oil & gas we will be able to extract to power our economies’ future growth:

1. **Geology**: the actual physical presence of oil & gas molecules in rock formations.
2. **Technology**: the equipment, materials, systems and procedures which allow us to find and extract oil & gas from those rock formations, and how much.

3. **Price**: the key benchmark against which field development and oil & gas production costs must be justified.

4. **Above Ground Constraints**: the permitting, environmental regulations, water and infrastructure availability which will allow for the profitable development of the field and disposal of its production.

It is clear that, over the years, as energy prices have gone up, “reserves” have also gone up because higher prices justified the use of existing but more expensive technologies and the development of new technologies to recover harder-to-get molecules, either from existing reservoirs or from hitherto unreachable or unexploitable formations.

For existing reservoirs for example, a recent study by the US Geological Survey has concluded that the proven reserves of oil in 186 well-known “giant fields” around the world increased from 617 billion bbl to 777 billion bbl between 1981 and 1996. And this is before the immense technical innovations which the industry has witnessed in the last 15 years.

The extent to which technological progress has kept increasing “Proven Reserves” and “Remaining Recoverable Resources” since the early days of oil production is remarkable.

The example below illustrates the interplay between technological improvements and a field’s productivity at increasing oil prices. In Section XI below, we provide another example of how current technical innovation efforts by large oil companies may unlock large crude reserves, if oil prices justify the investment and extraction costs.

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**HOW TECHNICAL ADVANCES DRAMATICALLY INCREASE OIL RESERVES ESTIMATES**

**The Kern River Field in California.** When the Kern River Oil Field was discovered in 1899, analysts thought that only 10 percent of its unusually viscous crude could be recovered.

In 1942, after more than four decades of modest production, it was estimated that the field still held 54 million barrels of recoverable oil, a fraction of the 278 million barrels already recovered. In fact industry observers famously remarked that “in the next 44 years, it produced not 54 million barrels but 736 million barrels, and it had another 970 million barrels remaining.” But even that estimate proved incorrect.

In November 2007, Chevron, by then the field’s operator, announced cumulative production had reached two billion barrels. Today Kern River still yields nearly 80,000 barrels per day, and the state of California estimates its remaining reserves to be about 627 million barrels.

Chevron began to increase production markedly in the 1960s by injecting steam into the ground, a novel technology at the time. Later, new exploration and drilling tools, along with steady steam injection, turned the field into a kind of oil cornucopia, with reports of Chevron on its way to pumping as much as 80% of the crude.

To conclude, **“global oil & gas reserves” is not a static concept.**

Instead, the amount of oil & gas which we will be able to recover from existing and yet-to-be-developed or discovered fields will be largely determined by (i) the cost of energy - price of oil - and (ii) the technological developments which will justify the extraction of increasingly-hard-to-reach oil & gas resources.
Conclusion

As technology moves forward, we should expect oil & gas reserves to keep increasing, depending upon (i) the energy demand and price expectations which will justify the necessary capital investments and (ii) the increasingly strict constraints which society will likely impose to minimize or simply to preclude any risk of environmental damage.
III. RECENT TECHNOLOGICAL DEVELOPMENTS

As mentioned above, it is because of developments in various finding and extractions technologies that the oil & gas industry has powered our societies' growth for more than a century now.

A. Injection

Originally, the key innovation to extract more oil from the reservoirs was to inject gas under pressure to restore the pressure lost during the primary recovery, or to inject water to raise the oil up towards the well. As time passed, this evolved into more and more powerful and sophisticated processes to inject steam to push the oil to the well and to inject chemicals to facilitate the migration of the oil droplets through the host rock by lowering their viscosity.

Today, as discussed in Section VII below, oil producers in shale formations inject water, sand and special chemicals in the formation to crack the rock and to facilitate such migration of hydrocarbons towards the wells. Industry observers routinely report North American operators using new “secret recipes”, adapted to the specific characteristics of each shale, to improve their wells’ performance (flattening and lengthening their decline curve).

As discussed below, a key issue with oil & gas production from shale formations is that the “reach” of each well is limited, so that (i) hydrocarbon production declines faster and (ii) significantly more (expensive) wells need to be drilled to sustain production, than for normal reservoirs. Whether tight oil and shale gas production will continue to rise will thus depend to a large extent on improvements in the formulation and use of chemicals which will reduce the surface tension and ease the movement of hydrocarbons towards the wells. Oil companies and industry experts express confidence that such improvements will continue to occur.

B. 3D Seismic

By sending acoustic waves from near the surface and listening for echoes from deeper boundaries between layers of different rocks, engineers are able to get a good picture of where hydrocarbon-rich formations are located. With increased knowledge on how best to interpret the sub-surface images, and with massively more powerful computing power, engineers define increasingly precisely the geometry and geologic characteristics of the “payable zones”.

This has truly revolutionized the oil exploration industry in the last decades, in particular in two key aspects: first in being able to locate the reservoirs’ “sweet spots” precisely and thus to drill wells at the most attractive location (key to the economics-to-date of tight oil and shale gas production), and second, when coupled with other geophysical detection methods, in being able now to image below salt sub-sea oil reservoirs (key to deep-water oil production).

C. Horizontal drilling

The industry has known for many years how to change the direction of a well from vertical to another angle, including horizontal. The key technical development starting in the 1980s however has been the ability to control, in three dimensions, at exactly which new angle the drill would turn, in rocks of different geophysical properties, to direct the well with great precision over long distances to the target zones.
This has not only reduced the number of wells needed to extract oil from a reservoir, but it also allowed the reaching of sections which would otherwise not be reachable or economic, when hydrocarbons are in thin horizontal layers for instance. This applies not only to new resources, but also to the re-exploitation of existing resources.

Further, the development of multilateral wells - wells with multiple branches radiating from one main borehole – has allowed operators economically to access various zones of deep reservoirs. This has in particular justified the drilling of very (large) deep water oil reservoirs which can only be exploited economically from one single facility.

Multibranched horizontal wells

D. Mining and Refining of Oil Sands

Oil sands – also called bituminous sands or tar sands – are deposits of sand or loose sandstone and clay saturated with bitumen, a heavy, dense and very viscous form of petroleum. The mining and upgrading of these deposits started in the late 1960s in Canada, which still hosts the only commercial oil production from this type of resources. The mining and purification of oil sands is expensive, and the bitumen produced is a particularly heavy type of crude. Bitumen is either diluted with gas condensates or light oil for export to US Gulf Coast refineries, or it is processed near the mine into light crude.

Over the last 30 years, three technological developments have enabled the economic mining and refining of oil sands.

First mining itself has experienced massive productivity improvements and cost decreases over the period. For instance, the world’s largest haul trucks in 1980 carried 70 tonnes of ore; today they carry more than 350 tonnes. Also, computerized mine planning and management methods have significantly improved the identification of high grade zones (and thus the definition of optimal operating plans), as well as the fleet movements and the productivity of pit operators. Mining industry observers estimate that the unit generic cost of digging a tonne of ore is now about 40% lower than in the late 1970s.

Second, for those zones of the deposits which cannot be mined economically in typical shovel and truck open pit operations, bitumen in the sand can now be extracted by melting the bitumen with steam and having it flow into horizontal wells at the bottom of the formation. Obviously, this “Steam Assisted Gravity Drainage” (SAGD) method relied on the concurrent development of horizontal drilling techniques. Industry observers estimate SAGD-bitumen to cost about 30% less than that produced by other methods.
And third, natural progress in refining technology has significantly improved the recovery of hydrocarbons from the sand and the upgrading of the bitumen into lighter crude.

The mining and refining of oil sands is still considered by most as expensive, in particular since it produces heavy lower-value crudes. Yet, as the marginal source of oil to the US refineries, it has flourished to date thanks to continued improvement in mining and bitumen processing technologies.
IV. GLOBAL DEMAND OUTLOOK FOR ENERGY

A. Global Demand

Numerous institutions analyze and comment on the status and outlook of the global energy industry. Most observers consider that the yearly “World Energy Outlook” publications by ExxonMobil, by the IEA, by the US EIA, and by British Petroleum (BP) provide insightful views of the industry and its likely evolution.

These publications are based on extensive databases and credibly precise assessments of medium- and long-term technical and commercial developments for both the demand and the supply of world energy. For this report, we have reviewed these publications as well as several others from specialized government agencies, private institutes, academia, and specialized consulting firms.

As it provides analyses and forecast for a longer period than the IEA, US EIA and BP publications, and for simplicity and clarity, we have elected to use, and adapt for this report, ExxonMobil’s data, analyses and projections, as they present in their 2013 publication: “The Outlook for Energy: A View to 2040”. These data, analyses and projections are broadly in line with those published by the IEA, US EIA and BP, and all key trends and conclusions are similar.

History has shown a strong correlation between economic growth and energy consumption growth. The two key assumptions in forecasting global energy demand are thus (i) the rate of growth of the world’s various regions, and (ii) the levels and changes in the energy intensity of these regions’ economies.

It is well recognized that technical improvements in industrial processes and increased energy efficiency in transport and building infrastructure have already significantly reduced the energy intensity of advanced economies. It is also recognized that, whilst they will also experience a “material intensive” GDP-per-capita growth period, the world’s other regions will follow a new more energy efficient path towards prosperity than the West experienced with last century’s technologies.

Through detailed country-by-country, sector-by-sector and technology-by-technology analyses, economists from governments and private industry thus build precise estimates of future energy demand, (i) to assist with correct public policy formulation and, through widely distributed publications, (ii) to educate the public at large and to encourage hoped-for private sector industrial investments.

The graph next page shows ExxonMobil’s estimate of future global energy demand to 2040, including expected substantial (about 35%) energy savings through efficiency gains. Again, estimates from other sources such as the IEA, the US EIA and BP offer similar trends and conclusions. Attachment 1 provides the conversion factors to reconcile these reports’ data when they are expressed in different units.

On the basis of a world GDP growing at 2.8% p.a. on average between 2010 and 2040, and as the graph next page also shows, Global Energy Demand is expected to grow at an average of 1.0% p.a. from 13.2 billion tonnes of oil equivalent (toe) in 2010 to 17.8 billion toe in 2040.

Attachment 2 breaks down in detail global energy demand growth per sector, uses and source of energy.
GDP and Global Energy Demand

B. Regional Breakdown

In terms of regional demand, and as the graphs below show, the West (North America & Europe) and Asia each accounted for 38% of the world’s global energy consumption in 2010. With rapid economic growth, Asia is expected to account for 45% of the world’s energy consumption by 2040, and the West 27%. This corresponds to an average growth of 1.5% p.a. in Asia, and an average contraction of -0.1% p.a. for the West.

Global Energy Demand by Regions (in billion toe)

Source: ExxonMobil – Outlook for Energy, 2013
C. End Uses

As the graphs below show, electricity generation (including electricity used in the transportation and residential / commercial sectors) and industrial production accounted for 36% and 30% of global energy consumption respectively in 2010. Transportation (the major user of oil) accounted for 18% of the world’s global energy consumption in 2010.

With the expected rapid production and consumption of electricity globally, electricity generation is expected to account for 41% of global energy demand in 2040 and industrial production 28%. This corresponds to an average growth rate of 1.4% p.a. of energy consumed in electricity generation, and 0.7% for industrial production. (Energy used in transportation is also expected to grow at a relatively rapid 1.1% p.a.)

![Global Energy Demand by Primary Use](image)

*Source:* ExxonMobil – Outlook for Energy, 2013; Jadwa Investment

D. Sources of Energy

The production and use of various sources of energy will evolve over the period considered. Whilst oil, gas and coal accounted for 81% of all energy consumed in 2010, they will account for only 77% in 2040. Of particular interest is the rapid growth of use of gas in electricity production, at the detriment of coal (gas represented 22% of all energy consumed in 2010; it will represent 27% in 2040 - coal accounted for 26% of energy consumed in 2010; it will represent 19% in 2040). Nuclear and renewable energies are expected to grow more rapidly than oil, gas and coal, but from a much smaller base; from 19% in 2010, they are expected to account for 23% of global energy production in 2040.

![Global Energy Sources](image)

*Source:* ExxonMobil – Outlook for Energy, 2013; Jadwa Investment

E. Different Sources of Energy for Different Uses

Clearly, different sources of energy are best suited for various uses. The graphs next page show how, on a global basis, the use of oil, gas, coal, nuclear, hydro and
renewables will evolve (along with the increasing intermediate production of electricity) between 2010 and 2040.

The graphs show that oil & gas will continue to account for about 36% of the energy used in the residential / commercial sector globally between 2010 and 2040. They show also the rapidly increasing consumption of electricity in the residential / commercial and industrial sectors; electricity accounted for 28% of the energy used in 2010 in the residential / commercial sector, it is expected to account for 41% in 2040. Electricity will accounted for 16% of the energy used in the industrial sector in 2010, and it will account for 21% in 2040.

The graphs also show that oil will continue to account for almost all of the energy used in the transport sector (from 95% in 2010 to 89% in 2040). As mentioned above, the energy used in transportation is expected to grow at a relatively rapid 1.1% p.a., and overall use of oil for global transport activities will grow from 2.5 billion tonnes of oil equivalent to 3.6 billion tonnes equivalent between 2010 and 2040. Oil & gas will retain their 55% share of energy production for industrial uses. Of particular interest is the rapid increase of use of gas for electricity generation, from 24% in 2010 to 29% in 2040, with coal’s share in electricity production declining from 45% to 32%.

Global Energy Demand by Uses and Sources – 2010-2040

Source: ExxonMobil – Outlook for Energy, 2013; Jadwa Investment
Conclusions

1. Energy demand will grow less rapidly than overall GDP growth because of large efficiency gains in energy uses. Yet, global energy demand will grow at an average of 1.0% p.a. from 13.2 billion toe in 2010 to 17.8 billion toe in 2040. Energy demand will grow most in Asia where 45% of all energy will be used in 2040.

2. There will be notable shifts in the use of energy, in particular with electricity generation growing rapidly to represent 41% of global energy use in 2040 (from 36% in 2010). There will concurrently be shifts in the sources of energy, as gas will grow to account for 29% of electricity production in 2040 (up from 24% in 2010) while coal will account for 32% of electricity production (down from 45% in 2010). Nuclear, hydro and renewables will increase their share of global energy sources from 18% in 2010 to 23% in 2040.

3. Oil & gas will still represent, by far, the major sources of energy for the world. They will represent 59% of all energy used in 2040, up from 56% in 2010. The major growth will be for gas. It will grow at 1.7% p.a., whilst demand for oil will grow at a more modest rate of 0.8% p.a. Oil will continue to be used mainly for the transportation and industrial sectors, and gas for the electricity and industrial sectors.

4. We view the two key questions to be whether (i) the energy intensity of the world economy will decrease by as much as 35% in the next 30 years, which most observers assume, and (ii) Asian GDPs will continue to grow at the relatively high rate, which most observers also assume.
V. GLOBAL DEMAND OUTLOOK FOR OIL & GAS

As discussed above, the global demand for oil / liquids and for gas is expected to grow substantially between 2010 and 2040. Attachment 3 breaks down the global demand growth for oil & gas per end uses.

A. Oil & Liquids

Oil demand will grow from 4.5 billion toe in 2010 to 5.6 billion toe in 2040, a growth of 0.8% p.a. on average. As the graph below shows, this will be propelled by a significant increase in global transportation needs and industrial activities.

Global Oil & Liquids Demand (in billion toe)

Source: ExxonMobil – Outlook for Energy, 2013; Jadwa Investment

B. Natural Gas

Gas demand will grow faster, from 2.9 billion toe in 2010 to 4.7 billion toe in 2040, a growth of 1.7% p.a. on average. As the graph below shows, this 1.8 billion toe increase will result from a significant increase in gas use for electricity generation (1 billion toe) and for industrial activities (0.6 billion toe).

Global Gas Demand (in billion toe)

Source: ExxonMobil – Outlook for Energy, 2013; Jadwa Investment
These large increases in oil & gas demand between 2010 and 2040 are predicated on three fundamental assumptions:

1. A reasonably sustained rate of growth of the global economy (2.8% p.a. on average over the 30 years);
2. Continued significant improvements in the efficiency of energy uses across regions and across residential / commercial, transportation and industrial activities (including electricity production); and,
3. Economic and environmental considerations will continue to favor oil for transport activities and will increasingly favor gas for electricity generation.

No observers seriously question these assumptions, and, whilst they may at the margin differ on some specific numbers, public officials and industry participants thus view the above forecast as solid base cases for long-term policy-making and investment planning.

The remainder of this report focuses on:

(i) Where and how producers will find and extract the oil and the gas necessary to meet the needs forecast above?
(ii) What role new “unconventional” sources of oil & gas may play on the global energy markets? And,
(iii) What are the medium- / long-term consequences for Saudi Arabia?
VI. GLOBAL SUPPLY OUTLOOK FOR OIL & GAS

Many hydrocarbon reservoirs contain a mix of crude oil and natural gas. In fact, a significant production of hydrocarbon molecules is in the form of NGLs that are associated with the production of crude oil or sometimes also come from wells primarily drilled for gas. These NGLs are separated from crude oil and natural gas (methane); they are processed and sold separately to realize their full value.

The industry looks at the supply of oil & gas by (i) grouping all the liquids with straight crude oil production and by (ii) isolating natural gas production which has much different downstream processing and value chains.

As they do for global oil & gas demand, several institutions regularly publish their forecast of global oil & gas production. They base their projections on the specific characteristics of all known fields (OPEC and non-OPEC) and their likely production profile, taking into account expected technology-driven increased recoveries and the exploitation of new reservoirs. As for oil & gas demand, these various forecast for oil & gas production tend not to vary dramatically from consensus trends. Indeed, all institutions promptly account for significant discoveries when these may add to the potential supply of oil & gas. This was specifically the case two years ago when all observers started to forecast significant new oil & gas production from tight (including shale) formations in the US.

As for the global Energy Demand Outlook, after reviewing forecasts from the IEA, US EIA and BP, and for overall consistency, we have elected to use and adapt ExxonMobil’s data, analyses and projections as presented in their 2013 “Outlook for Energy: A View to 2040”. The IEA’s “World Energy Outlook 2012” report provides some more detailed data and discussion of (i) the factors that affect the future production of crude oil, hydrocarbon liquids and gas and also of (ii) the evolution of the sources of crude, liquids and gas supplies. We thus also refer to IEA’s data in this Section (we quote the data corresponding to their “New Policies” scenario which is broadly in line with ExxonMobil’s analyses and forecast).

We note that ExxonMobil’s forecast covers the 2010-2040 period, whilst the IEA’s covers the 2011-2035 period for liquids and the 2010-2035 period for gas. Attachment 4 shows the IEA’s forecast supply of liquids to 2035. Attachment 5 shows the IEA’s forecast supply of gas to 2035.

A. Oil and Liquids

The Graph next page shows ExxonMobil’s estimate of the global supply of crude oil and liquid hydrocarbons to 2040. It is expressed in “millions of oil-equivalent barrels per day”, but, when converted for average specific gravities, it matches with the global demand for oil demand as shown in “billions of tonnes of oil equivalent” in Section V above (conversion factors in Attachment 1). It shows that liquids supply will increase by 30% from 87 million bpd in 2010 to 113 million bpd in 2040.

Crude oil production from conventional sources will slightly decline over time. Indeed, the natural decline from currently producing fields will not be matched by increased production from the known fields yet to be developed and from fields yet to be found.

Conversely, crude and liquids production from NGLs and unconventional sources will increase rapidly and will constitute the key new source of liquid hydrocarbons to meet long-term liquids demand.
Global Supply of Liquids – 2000-2040

Source: ExxonMobil – Outlook for Energy, 2013

As the graph above shows, ExxonMobil’s foresees global conventional crude oil production to decline over the long term. In its “Current Policies Scenario”, the IEA also expects global conventional crude oil production to decline, from 68.5 million bpd in 2011 to 65.4 million bpd by 2035 to represent only 67% of global oil production in 2035 (versus 81% in 2011).

Conversely, crude and liquids production from NGLs and unconventional sources will increase rapidly and will constitute the key new source of liquid hydrocarbons to meet long-term liquids demand.

NGLs will also increase rapidly (from 12.1 million bpd in 2011 to 18.1 million bpd in 2035) not only because a significant portion of the to-be-developed gas fields in the Middle East and of the shale gas fields in the US have high NGLs content, but also because most observers expect Russia, Nigeria and Iraq, amongst others, to reduce the wasteful flaring of the associated gas they produce with their oil.

Unconventional fuel supplies – deep-water, oil sands and tight oil – will experience by far the highest increase in oil production, from 3.9 million bpd in 2011 to 13.2 million bpd in 2035. This rapid growth will account for as much as 75% of the increase in crude oil supply needed to meet global oil demand. As the graph next page shows, the IEA estimates that these unconventional sources of crude oil will represent 14% of Global Oil Production in 2035, up from 5% in 2011.
As ExxonMobil, the IEA also expects that biofuels production will increase rapidly. This will however be from a small base, so that, in spite of more than trebling their production, biofuels will only account for 4% of Global Liquids Supply by 2035, up from 1% in 2011. When added to expected gains in processing, the overall contribution of non-oil sources to total liquids supply will grow from 4% of Global Liquid Supply in 2011 to 7% of Global Liquids Supply in 2035. We do not address biofuels in this Report.

In terms of geographical distribution and groups of oil producers, the IEA forecasts a rapid decrease of conventional oil production by Non-OPEC countries (from 39.2 million bpd in 2011 to 31.6 million bpd in 2035). In absolute terms, Non-OPEC countries will compensate this loss by increasing their production of NGLs and, much more importantly, by increasing their production of unconventional sources of oil (from 3.2 million bpd in 2011 to 10.4 million bpd in 2035). OPEC, on the other hand, will significantly increase its production of conventional oil (from 29.3 million bpd in 2011 to 33.9 million bpd in 2035), and of NGLs. OPEC’s increase in unconventional oil will be much more limited.

Overall, as the graphs below show, global production of oil will increase from 84.5 million bpd in 2011 to 96.7 million bpd in 2035. OPEC’s overall share of that global oil production will increase from 42% in 2011 to 48% in 2035, and Non-OPEC producers’ share will decline from 58% in 2011 to 52% in 2035.

It should be noted that, with their increased focus on this new potential supply of oil, official institutions and industry players continue to report increases in global tight oil resources.

As recently as June 2013 for instance, the US EIA increased its estimates of global technically recoverable tight oil resources to 10% of global oil reserves. It increased its estimate of US technically recoverable tight oil reserves from 32 billion barrels to 58 billion barrels.
It also estimated that Russia has up to 75 billion barrels of technically recoverable tight oil, China up to 32 billion, Argentina up to 27 billion and Libya 26 billion. As discussed in Sections VII and XI below however, it is yet unclear whether, when and how efficiently these resources will actually be exploited, both because of (i) the still-not-well-known specific characteristics of the host rocks, and, most importantly, because of (ii) still-inappropriate legal, logistics and environmental frameworks.

**Liquid Fuels Supply – Conclusions**

1. *Future global liquid fuels demand will be met by a rapidly evolving supply of conventional oil, NGLs, unconventional sources of oil (including biofuels to a small degree).*

2. *Confronted with a steep decline in conventional oil production, Non-OPEC countries will most significantly increase their production of unconventional oil: tight oil, deep-water, oil sands and extra heavy crude.*

3. *OPEC will increase its production of conventional and (to a lesser degree) unconventional oil, raising its share of global liquids production from 42% in 2011 to 48% in 2035.*

4. *The increase in oil production from unconventional sources will provide by far the largest contribution to meeting the forecast increase in oil demand.*

5. *The IEA indeed estimates that unconventional oil sources (deep-water, tight oil and oil sands) will contribute up to 72% of the increase in global oil supply (57% of the increase in global liquids supply) needed to meet demand.*

*Thus, the one key issue when looking at the long-term outlook for oil production and Saudi Arabia’s likely future position in the global energy market is whether and to what extent such large anticipated production of tight oil and other unconventional liquid fuels sources will materialize.*

Sections VII and VIII below will thus look at whether:

(i) the resource base for these unconventional sources of oil and liquids are large enough;

(ii) the technology to extract the oil from these unconventional reservoirs is economic enough at forward oil prices; and,

(iii) the regulations – including environmental permits - and the above ground factors (legal, infrastructure, logistics and societal considerations) are favorable enough to justify the exploration, development and exploitation of these fields.

**B. Natural Gas**

The Graph next page shows ExxonMobil’s estimate of the global supply of natural gas to 2040. It is expressed in “billions of cubic feet per day”. When converted for the average energy content of gas and the specific gravity of oil, it matches with the global demand for gas shown in “million toe” in Section V above.
Global supplies of natural gas increase dramatically between 2010 and 2040, in large part through the rapid development of shale gas production in North America.

Indeed, ExxonMobil forecast gas production to increase about 65% between 2010 and 2040, with 20% of gas production occurring in North America by then. It also notes that this shift towards gas will have substantial environmental benefits since gas is the least carbon-intensive of the major energy sources (it emits up to 60% less CO\textsubscript{2} emissions than coal when used in power generation).

**Global Natural Gas Supply – 2010-2040**

All observers agree that global reserves of natural gas are large. In their 2012 reports, ExxonMobil and the IEA estimated that there was about 28,000 tcf remaining of natural gas resources, enough to meet current demand for more than 200 years. Globally, 60% of these reserves are from conventional fields, and 40% come from unconventional (35% shale and 5% coalbed methane formations).

All observers note the potential to find more substantial gas resources, in particular in areas richly endowed with oil and conventional gas such as Africa, Eurasia and the Middle East.
Industry publications regularly report new gas discoveries as reservoirs are better explored and advances in the understanding of the reservoirs’ geology and in recovery technologies are deemed significant enough to enable the possible commercial exploitation of otherwise uneconomic resources.

As for tight oil, reports of increases in global gas resource estimates are thus frequent; this has indeed been the case between the publications of the early-2013 ExxonMobil and mid-2012 IEA reports upon which this report is based and mid-2013 when it is published.

The graph below illustrates the IEA’s estimate of remaining recoverable gas reserves as of 2011

**Remaining Global Resources of Gas as of 2011**

![Remaining Global Resources of Gas as of 2011](image)

*Source: IEA, as quoted in ExxonMobil’s “Outlook for Energy, 2013”*

In term of production, the world will experience significant changes in where gas is produced, from what sources, and how it will be traded to satisfy demand. As the graphs next page indicate, the IEA estimates that gas production will increase by 51% between 2010 and 2035, (ExxonMobil foresees a 65% increase to 2040) with the largest increases coming from Asia/Pacific (China & Australia), East Europe (Russia), the Middle East (Qatar, Iraq and Iran), and North America (US). Overall, half of the increase will come from unconventional sources. Unconventional gas production will in particular increase rapidly in the North America for which ExxonMobil expects unconventional gas sources to account for as high as 80% of total gas supplies by 2040.

As the graph next page shows, the IEA forecasts that, overall, unconventional sources of gas will represent 26% of global supplies by 2035, up from 14% in 2010.
Global Gas Supply 2010-2035, by sources

![Global Gas Supply 2010-2035, by sources](image)

- **Production 2010:** 317.6 bcf/d
- **Production 2035:** 479.2 bcf/d

*Source: IEA - World Energy Outlook, 2012*

Gas will also experience a rapid increase in inter-regional trade, from 65 billion cubic feet per day in 2010 to 116 billion cubic feet per day in 2035, a 77% growth. More than 20% of the investments in the LNG infrastructure necessary to support such inter-regional trade were already under construction in mid-2012. (Whilst pipelines transport gas over land, an increasing proportion of gas is shipped as LNG over long distance across the oceans.) The European Union in particular is expected to account for an increasing large share of LNG import, reaching about 50 billion cubic feet per day in 2035, or 44% of total inter-regional gas trade. Traditionally, LNG has been priced on the basis of long-term contracts; with the development of a large and deep LNG trade, international gas pricing may evolve towards a more fluid market, which some expect could end up reducing gas price, another factor in increasing gas use.

Global Gas Supply 2010-2035, by regions

![Global Gas Supply 2010-2035, by regions](image)

- **Production 2010:** 317.6 bcf/d
- **Production 2035:** 479.2 bcf/d

*Source: IEA - World Energy Outlook, 2012*

**Natural Gas Supply – Conclusions**

1. **Global gas production is expected to increase by about 65% between 2010 and 2040 (51% between 2010 and 2035).** This rapid increase in gas production will provide by far the largest contribution to meeting the world’s increased energy needs.

2. **The large majority of the increase in gas production is expected to come from East Europe/Eurasia, the Middle East and the Asia-Pacific regions.**

3. **Unconventional gas supplies are set to play a central role in this increased gas production.** Observers assume indeed that **shale gas** will account for **about half of the forecast global gas production increase.** Most assume that this will come from the US and a few large basins in Asia.
Natural Gas Supply – Conclusions (continued)

4. Inter-regional gas trade will also increase rapidly with the development of significant LNG infrastructure and a more fluid international gas market.

The one key issue when looking at the long-term outlook for natural gas production is whether and to what extent such large anticipated gas production will materialize.

It should be noted that Saudi Arabia is not a large player in the world’s natural gas (methane) industry, and should thus not be directly affected by these developments.

Saudi Arabia is a however a very large player in the global petrochemical industry, which is based on ethane and NGLs. Thus, the one key issue when looking at the impact of shale gas production on Saudi Arabia is whether and to what extent the large anticipated production of cheap ethane and NGLs from US tight oil and shale gas fields will materially affect global petrochemical margins and thus the long-term relative profitability of Saudi Arabia’s large petrochemical industry.

Section IX below looks at whether, to which extent, and under which conditions, unconventional sources of gas will actually be developed and help meet the world’s rising global energy demand.

Section X below looks at how ethane and NGLs production from shale fields in the US will affect Saudi Arabia’s petrochemical industry.
VII. TIGHT OIL PRODUCTION & OUTLOOK IN THE US

A. The Basics of Tight Oil (and Shale Gas) Production

The presence of hydrocarbons in deep impermeable shale formations has been known for a long time. It is however only in the last 15-20 years that, first for gas and then for oil, US entrepreneurs combined hydraulic fracturing and horizontal drilling to extract hydrocarbons profitably from these hitherto uneconomic reservoirs.

Basically, as the picture next page shows, hydraulic fracturing – “fracking” – consists in digging a (classical) vertical oil well, to reach the impermeable layer of shale rock deep below the surface. The well is then sent horizontally to reach the target zones, and large amounts of very hot water, sand and chemicals are injected under high pressure to fracture the rock and to allow gas and oil to migrate to the well bores.

It must be noted from the outset that, obviously, since the shale rock is highly impermeable, only a limited amount of rock adjacent to the induced and natural fractures can be drained. Tight oil wells will thus experience rapid declines in production. There is considerable variability within tight oil plays, with smaller “sweet spots” and larger less productive areas. Obviously, early production is concentrated on the sweet spots. Finally, due to their high decline rates, these plays require high levels of capital input for drilling and infrastructure development to maintain production levels. This is discussed further below.

It must also be noted that, since the shale is highly impermeable, there cannot be migration of polluting fracturing liquids from the fracture zone to the aquifers high above. Thus, liquid pollution, if any, will come from inadvertent discharges of normally controlled flowback liquids streams. Similarly, gas pollution (methane from the various rock layers may escape from the well or its casing) should normally be controlled in classical gas recovery and storage systems.

PRODUCTION OF SHALE RESOURCES IN THE UNITED STATES
(Extracts from “Technically recoverable shale resources” US EIA, June 2013)

The use of horizontal drilling in conjunction with hydraulic fracturing has greatly expanded the ability of producers to profitably produce oil and natural gas from low permeability geologic formations, particularly shale formations. Application of fracturing techniques to stimulate oil and natural gas production began to grow in the 1950s, although experimentation dates back to the 19th century. The application of horizontal drilling to oil production began in the early 1980s, by which time the advent of [new technologies] brought [shale exploitation] within the realm of commercial viability.

The advent of large-scale shale gas production did not occur until around 2000 […] in the Barnett Shale. As commercial success of the Barnett became apparent, other companies started drilling wells in this formation so that by 2005, Barnett alone was producing almost half a tcf/yr. of natural gas. As natural gas producers gained confidence in their ability profitably to produce natural gas in the Barnett Shale […], they began pursuing the development of other shale formations, including the Fayetteville, Haynesville, Marcellus, Woodford, and Eagle Ford shales.

The growth in tight oil production shows how important shale oil production has become in the United States. U.S. tight oil production increased from an about 0.2 million bpd in 2000 to an average of 1.9 bpd in 2012 for 10 formations. The growth in tight oil production has been so rapid that U.S. tight oil production was estimated to have reached 2.2 million bpd December 2012. Although EIA has not published tight oil proved reserves, EIA’s current estimate of unproved U.S. tight oil resources is 58 billion barrels […].

The graph next page provides a schematic of a tight oil or shale gas well.
Schematic of a tight oil or shale gas well

Source: Nature - “Should Fracking Stop?” September 2011
B. The US Tight Oil Plays

Tight oil production in the US has jumped from virtually nothing in 2004 to a reported 1.2 million barrel per day (22% all US production) in 2011 and an estimated 2 million bpd in 2012 (32% of all US oil production). Tight oil is generally of very high quality (it is sweet and light). Also, substantial amounts of natural gas are commonly produced in association with the oil.

It should be noted however that 81% of that production comes from only 2 plays: the Bakken play in North Dakota and Montana and the Eagle Ford play in southern Texas. As shown on the graph below, production from the US’ nineteen other plays has not increased significantly in the last 4 years.

![US Tight Oil Production by Plays - 2000 through May 2012](source)

1. **The Bakken Tight Oil Play** - Bakken in North Dakota and Montana was the first tight oil play significantly developed in the US. It remained the most productive as of mid-2012, with production of 568 thousand bpd of light sweet oil, from 4,598 operating wells. It also produced 0.6 bcf of gas, much of which was flared due to lack of downstream infrastructure. The average breakeven price for Bakken oil is the subject of considerable debate, with cost estimates ranging from $65/bbl to $80-90/bbl.

Bakken wells exhibit steep production declines over time. The graph next page illustrates a typical decline curve compiled from 66 months of production data prior to mid-2012. The first year decline is 69 percent and overall decline in the first five years is 94%. This puts average Bakken well production at slightly above the category of “stripper” wells in a mere six years.
The consequence of such decline curves is immediate: one needs to dig more and more wells to sustain, let alone increase, production. The graph below shows indeed the tight correlation between oil production and number of producing wells for the Bakken play between 2000 and mid-2012.

**Bakken tight oil production and number of producing wells – 2000 to mid-2012**

Obviously then, future increases in Bakken oil production will depend on the number of wells drilled annually, the productivity of these new wells, and the number of locations available to drill. In 2012, about 1,500 wells were drilled in the Bakken (at about US$10 million per well, this was a capital investment of about US$15 billion).
The US EIA Annual Energy Outlook 2012 estimated that 9,727 available well locations were left to drill in the Bakken as of January 2010, and an estimated ultimate recovery of 4.3 billion bbl. The graph below shows the Bakken oil production to 2025 if one (i) assumes drilling at current rate until all well locations are exhausted, and (ii) well productivity and decline pattern as experienced to date. It shows that the Bakken play’s tight oil production may decline at an overall field rate of 40% after peaking in 2017.

**Bakken Play’s Future Production Profile at Current Rate of Well Additions**

![Bakken Play's Future Production Profile at Current Rate of Well Additions](image)

Source: J. David Hughes, Post Carbon Institute, February 2013

Obviously, the production forecast above critically depends on (i) the productivity of the wells, and (ii) the number of available locations yet to drill.

The productivity of each well in turn depends on (i) how “sweet” are the zones left to drill and frack, (ii) what technology advances may allow for better recoveries than currently achieved, and (iii) how many available locations are left to drill.

Industry participants affirm that, as they understand the zones’ micro-geology better, technical progress is and will remain rapid, so that new wells will produce more oil and exhibit flatter decline curves. They also affirm that the plays are so large as still to contain numerous “sweet spots” so that the weighted average productivity of all producing wells will remain high. Whether these affirmations prove correct will determine how large of a role tight-oil will play in the US long-term crude oil supply.

Attachment 5 offers a brief description of the sophisticated technology and of the well management practices with which operators can significantly improve the recoveries of tight oil wells, if the reservoirs’ micro-geology allow.

The pictures next page show how intensely the most promising areas of the Bakken have already been drilled, and how extensive the reach of the horizontal wells already is.
Distribuion of wells in the Bakken play’s area of highest concentration

Source: J. David Hughes, Post Carbon Institute, February 2013

Wells in black in the map above are the top 20 percent in terms of initial productivity. Many of these sites are multi-well pads with two or more wells. The highest productivity wells tend to be concentrated in "sweet spots."

Distribution of horizontal wells in the Parshall “sweet spot” of the Bakken play

Source: J. David Hughes, Post Carbon Institute – February 2013

This area (right hand side of the map top of this page) is almost completely saturated with wells although there are still a few locations left. Green symbols indicate rigs drilling as of December 17, 2012.
2. **The Eagle Ford Tight Oil Play** - Eagle Ford in South Texas is the second largest tight oil play in the US. Whilst still in its youth, it exhibits overall productivity and production declines broadly similar to Bakken. As of June 2012, oil production from the Eagle Ford play totaled 524,000 bpd, from 3,129 wells. It also produced a large amount of associated gas, 2.14 bcf/d. The oil, condensate and dry portions of the Eagle Ford occur in separate but transitional parts of the play, about 30 miles apart. In its 2012 Energy Outlook report, the US EIA put the estimated ultimate recovery of the Eagle Ford at 2.46 billion barrels. Other sources have much higher technically recoverable reserves for Eagle Ford. The industry reports much activity at Eagle Ford, with 1,983 wells being added in 2012. The industry reports also that operators find success in improving their well’s productivity by adapting their fracking procedures and chemical additives to the specific geotechnical characteristics of the shale. Finally, the pipeline infrastructure linking Eagle Ford to Texas’ refining and gas processing centers is rapidly being improved which will increase further the long-term returns of Eagle Ford tight oil investments.

As for Bakken, the key drivers for the long-term contribution of Eagle Ford to the US’ crude oil production remain: (i) is the industry correct in affirming that continuing technological improvements will allow for significantly better recoveries and slower decline curves, and (ii) are the formations themselves so large and attractive as to promise a stable long-term strategic oil supply?

3. **Other US Plays** - Other plays are not reported to be developed as rapidly as Bakken and Eagle Ford, and their attractiveness is not confirmed as high as those two plays. The press relates in fact that some plays, in California in particular, are no longer being pursued. It is not clear whether this is temporary and results from (a) newly-found specific technical difficulties to exploit the California shale formations themselves (low production rates from initial wells), from (b) difficulties with Central Valley farmers who object to their water resources being affected by the huge water requirements of fracking operations, or from (c) other environmental / infrastructure reasons. It is also not clear whether the massive number of rigs being used in Bakken and Eagle Ford simply leaves enough physical rigs capacity to develop other fields in North America (the press reports indeed an acute shortage of rigs for Canada’s oil fields’ developments).

In any event, the graph next page forecasts long-term tight oil production in the US assuming that other plays are developed at current rates of wells productivity and production profiles, as Bakken and Eagle Ford taper off. It shows US tight oil production reaching, and possibly stabilizing at, about 750 thousand bpd in 2025, well below the 2.3 million bpd achieved in 2017.
Projection of tight oil production by plays in the US to 2025

Source: J. David Hughes, Post Carbon Institute, February 2013

It must be emphasized that this long-term projection is based on current understanding of the shale formations and fracking technology, which many commentators believe pessimistic.

Most industry participants, analysts and commentators predict indeed a continued large tight oil production after 2017, as yet-to-come technology advances continue to deliver higher oil recoveries from better known shale formations. In its “2013 Annual Energy Outlook”, the US EIA predicts a US tight oil production about 2.5 million bpd in 2025 (3.5 times more than the projection above), declining slowly to 2 million bpd in 2040.

US Oil Production 1990-2040
(in billion barrels per day)

Source: US EIA - Annual Energy Outlook 2013
The US EIA does not provide play-by-play detailed data supporting the above forecast. And it does warns that its projections are “highly uncertain and will remain so until they are extensively tested with production wells.”

Clearly, the US EIA long-term US tight oil production of 2 million bpd is significantly higher than the 750 thousand bpd projected on the basis of current well productivity, decline rates and rate of drilling based on now known available locations for 2025.

**Conclusions**

1. **US tight oil production as grown impressively from 200 thousand bpd in 2000 to an expected 2.3 million bpd this year. It now accounts for more than 30% of US oil production.**

2. **More than 80 percent of US tight oil production is from only two plays: the Bakken in North Dakota and Montana, and the Eagle Ford in South Texas.**

3. **There is great variability in the wells’ production in different locations of the plays, even at relatively short distances. To date, most of the “sweet spots” of the plays have been exploited.**

4. **Well decline rates are steep, between 81 and 90 percent in the first 24 months. This implies that about 40% of production must be replaced annually to maintain production.**

5. **Current drilling rates are high and production will thus continue to grow. However, ultimate recovery will depend upon the number of available drilling locations left, and these appear limited, in particular in Bakken.**

6. **It thus appears that US tight oil production may reach its maximum in 2017 and decline rapidly thereafter.**

7. **We note however that the estimates published by most industry observers and official institutions (including the IEA and the US EIA) are for US tight oil formations to yield a much higher and much longer production. Many reputable and knowledgeable industry players affirm that technological advances and better understanding of the micro-geology of the formations will allow for significantly higher and longer production from tight oil formations. We have not however found detailed justifications for such assertions in the technical press.**

8. **Whilst we agree that it will transform the North American energy landscape, we conclude by doubting that the production of oil from the US tight formations will significantly change the long-term structure of the world’s oil industry.**
VIII. ABOVE GROUND FACTORS AND GLOBAL OUTLOOK FOR TIGHT & SHALE OIL

A. The US Situation

As it developed its tight oil and shale gas production, the US has benefited from a unique set of favorable circumstances. Not only in geology and hydrology (good source rock not far from abundant water resources), but in what the industry calls “above ground” factors.

These “above ground” factors - governmental, industrial, legal, financial, infrastructural and societal considerations - are quite unique to the US and unlikely to be replicated elsewhere.

This started with the strong R&D support which US Federal Agencies provided to industry players in the 1980s and 1990s: three-dimensional micro-seismic imaging developed by the Sandia National Laboratories; early shale fracturing and directional drilling technologies and pilot tests developed by the Department of Energy; special tax credits for unconventional gas production between 1980 and 2002; public subsidization and cost sharing for demonstration projects, etc.

The other critical, unique, factors which fostered the development of the tight oil and shale gas industries in the US are: (i) a deep and vibrant set of private entrepreneurs, familiar with the costs, technologies and risks of drilling for oil or gas; (ii) a unique long-established engineering expertise in the exploration and definition of complex hydrocarbon reservoirs; (iii) a well-developed and low cost service industry to drill the wells and to provide and manage the necessary equipment; (iv) a legal system which rewards landowners for the profitable extraction of the hydrocarbon resources under their ground; (v) deep and liquid financial markets which provide efficient equity through partnerships and tailor-made debt to fund such specialized a-priori risky investments; (vi) the definition by the local governments and acquiescence by the local population of acceptable-to-the-industry environmental regulations; and, (vii) a transport infrastructure (network of pipelines, rail tracks or roads) which permitted connecting the new fields to refineries or gas processing / export centers.

Environmental Impact of Fracking. Of particular importance is the local population’s acceptance of fracking and of its likely environmental impact. Much opposition has been voiced against tight oil and shale gas production, in Europe in particular. Yet the actual environmental impact of fracking has not been well discussed. Given the nature and depth of the host tight and shale formations, water contamination of aquifers due to fracking appears implausible, if not impossible. Also, strict control of the flow-back liquids from the wells should not be more difficult than those (long proven satisfactory) for liquid effluents of surface industrial facilities. A particularly well-publicized concern has been the leaks of methane gas in the atmosphere with severe greenhouse effects. A recent study, sponsored by the Environmental Defense Fund (a US non-profit environmental advocacy group) and thus a-priori credible, concluded that proper classical containment equipment at the wellhead will capture 99% of the methane that could escape during well completion.

In all, whilst it does use abundant water resources, no serious case of ecologically damaging impact has been made against fracking. Indeed, all indications point to any environmental risk due to fracking being controllable if (i) properly strict environmental regulations are put in place and if (ii) properly tight well design and drilling and operational procedures for gas and liquid effluents control are followed. The rules recently published by the US Department of the Interior for oil and gas production on federal lands are a welcome first step in this direction.
Specific regulations to protect against water pollution from fracking will be issued next year by the US Environmental Protection Agency. They will provide additional design and operational standards for the continued environmentally safe development of fracking.

Societal Approach to Regulating Fracking. As of mid-2013, the California agricultural and oil industries are engaged with environmental groups and the state government in discussions to establish environmental protection regulations for tight oil production from the Monterey Shale. The Monterey Shale is under prime agricultural land in California’s South Central Valley, and the producers of high value crops there are naturally concerned that the large water requirements of fracking and the unregulated disposal of polluted flow-back liquids in open pits may damage their land and water resources. All parties are working with the State of California to issue regulations next year that reflect the consensus views on protecting the environment and yet allowing for the profitable exploitation of the Monterey Shale (assuming that it is geologically as attractive as currently surmised).

This consensual approach based on significant studies, input from and control by local interests and authorities, is not uncommon in the US and it differs from the more top-down approach of European governments. The difficulties and strongly negative publicity which the UK government recently faced as it pushed for shale gas developments in West Sussex show that the development of tight oil or shale gas resources may face serious societal opposition, and thus may not easily be developed, in West Europe and (apart from the US) other democratic societies.

In all thus, it appears that the US society may find it easier to regulate and accept the continued development of tight oil and shale gas production than European or other open societies.

This will likely influence the growth of global production of tight oil and shale gas as much as geological or economic factors.

**B. International Shale Oil Supplies**

As already mentioned above, and as exploration programs around the world start to yield results, industry and international institutions frequently report significant increases in estimates of global shale oil resources.

In May this year for instance, the US EIA estimated the “technically recoverable” tight oil resources at 345 billion barrels in the 42 countries it surveyed (this is about 10% of global crude supplies). It specifically estimated Russia to have the largest tight oil resources with 75 billion barrels, the US the second largest resources with 58 billion barrels (up from 32 billion estimated previously), followed by China with 32 billion, Argentina 27 billion and Libya 26 billion.

This month, IHS CERA – a respected oil & gas consultancy – published a report significantly increasing the resource estimates in the largest shale oil fields outside the US. They estimate that the 23 most promising fields outside the US and Canada could hold 175 billion barrels of extractable oil, compared with about 40 billion barrels in similar fields in North America. Of particular interest are the Bazhenov field in Siberia – which Russia advertises as key to offsetting the forecast decline in their conventional oil production - the Vaca Muerta field in Argentina, and the Silurian shales in Libya. In May 2013, the US EIA estimated unproven technically recoverable resources at 75.8 billion barrels for the Bazhenov field, 27.0 billion barrels at Vaca Muerta, and 26.1 billion barrels in Libya; this compares with their estimate of 58.1 billion barrels of unproved technically recoverable tight oil resources in the US.
So, the observers’ estimates of global tight oil resources are still very fluid and seemingly subject to upward adjustments. Yet, all point out that the geological data on, and understanding of, the technical characteristics of these fields are much less precise than for US reservoirs and that the estimates of recoverable oil are thus much less precise (see Attachment 6).

Indeed, in addition to geological uncertainties, industrial and economic factors may hamper or delay the exploitation of these fields. Most of these countries lack the US’ deep and efficient industrial and financial infrastructure to support tight oil and shale gas developments. The technology, equipment and infrastructure to extract the crude may thus simply not readily be available in the short- / medium-term to develop these fields.

This has a direct, critical, impact on costs, which in the end will determine whether a hydrocarbon resource is exploited. Industry observers estimate for instance that drilling a well for shale gas in Poland is three times more expensive than in the US. Indeed, the recent IHS CERA report referred to above found that costs for extracting tight oil reserves held in shale and other challenging rocks are significantly higher in other countries than in America, suggesting that they will need a higher oil price to be commercially viable.

In fact several non-US oil executives have publicly commented on the higher costs which their companies must incur to extract what they call the “technological barrels”.

Lastly, whilst industry observers and official institutions continue to increase their estimates of global tight oil resources, we are not convinced that such resources may quickly and easily be exploited to add significantly to global oil production. In addition to possible societal opposition to fracking, this is because both (i) the precise geology and oil recovery techniques for these fields are not yet mastered, and because (ii) the “above ground” factors which enabled the rapid growth of US tight oil production will not be as favorable in these new locations, particularly in terms of availability of cheap engineering, equipment services and transport infrastructure.

To a large degree thus, whether or not these extensive - and expensive - tight oil resources will be exploited, and how soon, will depend upon (i) new developments in fracking technology to recover oil from still-not-well-understood shale formations and (ii) the price of oil, as set by (a) how energy demand grows in the next decades and (b) how technological progress drive the production costs of alternative crude oil supplies.

### Conclusions

1. The US benefits from uniquely favorable “above ground” factors, which have enabled the rapid development of the tight oil production.

2. These are (i) technical (abundant water resources near the tight oil basins), and (ii) infrastructural (pipeline or rail transport facilities), (iii) industrial (numerous well-equipped and well-experienced industrial actors), (iv) legal and (v) financial.

3. Further, as long as environmental impacts are properly mitigated, the US society appears more receptive to the use of fracking to unlock tight oil production than other democratic societies where shale oil formations may exist.

4. Large shale oil formations have been identified in Russia, Argentina and Libya. We believe it too early to opine on whether and when these will be exploited, and the extent to which they may materially impact the world’s oil industry.
IX. SHALE GAS

A. The US Shale Gas Plays

As early as the late 1990s, the industry had recognized that the US possessed many shale formations from which gas could be extracted profitably through fracking. The map below shows the shale plays identified by the US Energy Information Administration.

Source: EIA, as reproduced by J. David Hughes, Post Carbon Institute, February 2013

Driven by a few mid-size gas companies willing to experiment with new technologies in the hope of fast returns, the US production of gas from shale formations started earlier and grew much faster than oil production from tight oil formations.

Shale gas production began in the Barnett play of East Texas in the early 2000s. The Haynesville play of East Texas and Louisiana, the Marcellus play of West Virginia and Pennsylvania, and the Fayetteville play of Arkansas were developed in the mid-2000s.

As of mid-2012, there were about 30 shale gas plays active in the US, with shale gas now accounting for about 40% of the US gas production, up from 2% in 2000.

As for tight oil production, but to a lesser degree, shale gas production is concentrated in a few plays. The graph next page shows that the top three plays – Haynesville, Barnett and Marcellus – accounted for 66% of total shale gas production as of mid-2012. Adding the next three plays – Fayetteville, Eagle Ford (South Texas) and Woodford (Oklahoma) – shows that six plays account for 88% of the US shale gas production.
As discussed below, each play has specific characteristics, and there are even wide variations in productivity within each play. These are critical to appreciating the long-term future of shale gas production in the US as decline curves for shale gas wells are often steeper than those for tight oil wells.

**US Shale Gas Production by Plays – 2000 to May 2012**

![Graph showing US Shale Gas Production by Plays]

*Source: J. David Hughes, Post Carbon Institute, February 2013*

1. **The Haynesville Shale Gas Play.** The Haynesville Shale is unique because of its high individual well productivity and overall large production – it was the most productive shale gas field in the US as of May 2012 (26% of the US shale gas production). The figure below illustrates the growth in both production and the number of producing wells since 2008. Production appears to have peaked at 7.2 billion cubic feet per day in November 2011 despite the continued growth in the number of producing wells (there were 2,802 wells in Haynesville as of May 2012.)

**Haynesville – Shale Gas Production and Number of Producing Wells**

![Graph showing Haynesville Shale Gas Production and Number of Producing Wells]

*Source: J. David Hughes, Post Carbon Institute, February 2013*
This is because Haynesville wells exhibit steep production declines over time. In fact, whilst the initial productivity of a few wells is very high (2% of wells initially produce over 20 million cf/d), most of the wells are less productive (about 8 million cf/d). With very steep decline curves (68% decline in the first year, and about 50% in the second, third and fourth years), overall production at Haynesville declines fast. In January 2013, Haynesville production was down 14% below the end-2011 peak, at 6.2 billion cf/d.

**Haynesville – Production Decline for pre-2011 Wells**

Thus, many new wells are required to offset the field’s overall decline, in particular since the new wells are unlikely to be as productive as the initial ones given that the play’s “sweet spots” have already been exploited. Indeed, assuming new wells with the productivity of those drilled in 2011, 744 new wells would have to enter production each year to offset the field’s decline. At an average of US$9 million per well, this is about US$7 billion per year capital investment, exclusive of leasing and other infrastructure cost, to keep production at current level. As of mid-2013, it appears that not enough wells are being drilled to offset Haynesville’s decline.

**Wells Distribution in the Haynesville Shale Gas Play**

Wells in black have the top 20 initial productivity. Many of these are multi-well pads with two or more wells. Highest-productivity wells tend to be concentrated in “sweet spots.”

*Source: J David Hughes*

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*Source: J. David Hughes, Post Carbon Institute, February 2013*
2. **The Barnett Play.** The Barnett shale play is where fracking was first demonstrated. It is the second largest producer of shale gas in the United States. Gas production peaked in November 2011 at 6.33 bcf/d, declined to 5.85 bcf/d in May 2012, when 14,871 operating wells were producing. Production has declined further and stood at a low of 4.84 bcf/d in June 2013.

Barnett declines are slower than for the Haynesville in the first year and much lower in the second and subsequent years. As with the Haynesville however, there is a wide variation of well quality in the Barnett play. Also, some wells in Barnett contain some oil and condensates, which significantly improves their profitability.

The figure below shows the production and overall decline rate of the Barnett play of all wells drilled prior to 2011.

![Barnett Field Decline of Pre-2011 Wells](image)

*Source: J. David Hughes, Post Carbon Institute, February 2013*

Assuming new wells produce for their first year at the first-year rates observed for wells drilled in 2011, 1,507 new wells would be required each year to offset field declines from current production levels. The current rig count, and thus the number of wells which can be drilled, is only about a third of what is required to offset the 30 percent per year field decline. Gas production at Barnett should thus continue gradually to fall, except if a major increase in gas prices justifies renewed intense drilling. Indeed, industry observers report that gas prices would have to reach and stabilize at US$5.5 per million BTU for producers to resume drilling at a rate that could push Barnett production back above 5 bcf/d.

3. **The Marcellus Play.** The Marcellus shale play underlies a very wide area of Pennsylvania, West Virginia, New York and Ohio. It has been growing very rapidly and surpassed Barnett in June 2013 as the second most productive US shale gas play. Production grew from 5.0 bcf/d from 3,848 wells in December 2011, to 5.5 bcf/d by June 2012, and to more than 7 bcf/d in March 2013. At this point, most of the production is in Pennsylvania and West Virginia.
Well quality is quite variable over Marcellus, with sweet spots already exploited in the northeast and southwest portions of Pennsylvania. Some wells also produce valuable NGLs and condensates in appreciable quantities so that liquids currently represent about 10% of Marcellus’ total output.

The industry reports wells of very high productivity in some areas, with lower decline curves than in other shale plays, so that there has been, and there still is, quite a feverish drilling activity in Marcellus. As of March 2013, there were about 7,000 wells being drilled, completed or in production in Marcellus.

The industry also reports significant advances in operators’ efficiencies and completion technologies, with better understanding of the play’s micro-geology (better drilling procedures, better drilling locations, better placements of lateral pipes and fracking stages, etc.), so that fewer rigs are drilling more more-productive wells.

Another factor which has enabled this rapid surge in gas production from the Marcellus shale is the fast development of gathering and transport infrastructure: field compression facilities, high pressure gathering lines and new pipelines extensions have enabled the efficient collection and delivery of gas to the energy-hungry North East US.

At this point, whilst the rig count in Pennsylvania has declined, most observers see a continued rapid increase in the production of Marcellus shale gas, up to 9 bcf/d or more as early as Q1 2014. This is not only because (i) there is a large backlog of wells that have been drilled but are not yet hooked up to pipelines (estimates vary from 1,000 to 2,000 of such already drilled wells not yet in production), because (ii) production should begin and gather pace from sweet spots identified in Ohio, and also because, critically, (iii) gas production from the Marcellus is economically attractive even at relatively low gas prices (whilst production costs obviously vary according to each well, observers estimate Marcellus gas production still to be economic at a relatively low gas price of US$3.5 per million BTU).

Whilst investment and production data are changing extremely rapidly in Marcellus, the clear prognosis for the Marcellus play is for continued growth. Marcellus gas will undoubtedly supply a major portion of the US gas needs. The play covers a vast area although clearly only small portions are highly productive. It is only with more extensive well productivity and decline data that the long-term outlook for Marcellus will be better assessed, and that the extent to which it may compensate for production declines from other less productive or uneconomic fields better understood.

4. The Other Plays. In all, the IEA reports on thirty shale plays in the US, with as mentioned above, the six top plays accounting for 88 percent of the US shale gas production. The paragraphs above discussed the top three plays. The next three - the Fayetteville, Eagle Ford and Woodford plays - add a further 22 percent. As of mid-2012, the remaining 24 shale plays, which cover much of the EIA’s shale play map, contributed only 12 percent of production.

Rising gas production in the Marcellus and Eagle Ford plays (the latter is discussed in Section VII) is offsetting declines in the Haynesville and Woodford plays, with the Fayetteville and Barnett plays declining slightly or, at best, remaining essentially flat.

Initial productivity and decline curve data on the remaining 24 plays show these plays to be generally of lower quality than the top plays.

Industry observers and official institutions nevertheless advance that, with forthcoming advances in the understanding of their geology and in drilling and fracking technology, these plays are to produce increasingly significant amount of gas between now and 2040.
B. Current Estimates of Remaining Shale Gas Resources in the US

The table below shows the estimates of remaining shale gas reserves and undeveloped resources in the US, as published by US EIA in May this year. It shows that Marcellus and Eagle Ford (with by-product liquids) and Haynesville (for dry gas) remain the key for long-term shale gas production in the US.

### US Remaining Shale Gas Reserves and Undeveloped Resources

<table>
<thead>
<tr>
<th>Distinct Plays (###)</th>
<th>Remaining Reserves and Undeveloped Resources (Tcf)</th>
<th></th>
<th>Distinct Plays (###)</th>
<th>Remaining Reserves and Undeveloped Resources (Billion Barrels)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Northeast</td>
<td></td>
<td></td>
<td>2. Southeast</td>
<td></td>
</tr>
<tr>
<td>* Marcellus</td>
<td>8</td>
<td>369</td>
<td>2</td>
<td>0.8</td>
</tr>
<tr>
<td>* Utica</td>
<td>3</td>
<td>111</td>
<td>2</td>
<td>2.5</td>
</tr>
<tr>
<td>* Other</td>
<td>3</td>
<td>29</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2. Southeast</td>
<td></td>
<td></td>
<td>3. Mid-Continent</td>
<td></td>
</tr>
<tr>
<td>* Haynesville</td>
<td>4</td>
<td>161</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>* Bossier</td>
<td>2</td>
<td>57</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>* Fayetteville</td>
<td>4</td>
<td>48</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>3. Mid-Continent</td>
<td></td>
<td></td>
<td>4. Texas</td>
<td></td>
</tr>
<tr>
<td>* Woodford*</td>
<td>9</td>
<td>77</td>
<td>5</td>
<td>1.9</td>
</tr>
<tr>
<td>* Antrim</td>
<td>1</td>
<td>5</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>* New Albany</td>
<td>1</td>
<td>2</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>4. Texas</td>
<td></td>
<td></td>
<td>5. Rockies/Great Plains</td>
<td></td>
</tr>
<tr>
<td>* Eagle Ford</td>
<td>6</td>
<td>119</td>
<td>4</td>
<td>13.6</td>
</tr>
<tr>
<td>* Barnett**</td>
<td>5</td>
<td>72</td>
<td>2</td>
<td>0.4</td>
</tr>
<tr>
<td>* Permian***</td>
<td>9</td>
<td>34</td>
<td>9</td>
<td>9.7</td>
</tr>
<tr>
<td>5. Rockies/Great Plains</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>* Niobrara****</td>
<td>8</td>
<td>57</td>
<td>6</td>
<td>4.1</td>
</tr>
<tr>
<td>* Lewis</td>
<td>1</td>
<td>1</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>* Bakken/Three Forks</td>
<td></td>
<td>6</td>
<td>19</td>
<td>5 14.7</td>
</tr>
<tr>
<td>Total</td>
<td>70</td>
<td>1161</td>
<td>35</td>
<td>47.7</td>
</tr>
</tbody>
</table>


C. The Economics of Shale Gas Production

Obviously, the expectation of adequate returns is what drives shale gas production in the US. With the extremely rapid growth in domestic (shale) gas supplies, wellhead gas prices plunged from US$10.8/million BTUs in July 2008, to a low of US$1.9/million BTUs in April 2012, and to US$3.8/million BTUs in August 2013.

As mentioned above, a typical shale gas well in the US costs between US$4 million and US$10 million to drill and complete. Since output declines rapidly, producers will basically drill only those wells which promise a rapid recovery of their investments. Whilst, as discussed above, well production varies widely amongst plays and within plays, the industry uses an average of about 1 bcf recovery for medium-depth plays such as Barnett, Fayetteville and Woodford, and slightly higher for the Marcellus and Haynesville. Gas prices above US$5.5 per million BTU are thus needed to justify drilling a shale “dry-gas” well. This is indeed the level which the press currently quotes to justify resuming drilling in the Barnett play.
The economics of shale gas production change dramatically however if the gas contains liquids since the value of condensates and NGLs is linked to oil prices. At current oil and gas prices, BTUs derived from oil are worth about 5 times more than BTUs derived from gas (hence the recent move towards gas powered trucks and buses in the US). Wells with “wet gas” are thus attractive at gas prices well below those for “dry gas”. Observers report that wet gas plays with liquids in excess of 25% are attractive even for gas at US$3 per million BTU.

The outermost case is that of associated gas produced from oil wells, as for tight oil from Eagle Ford. In that case, gas is essentially a free by-product, which, if the adequate infrastructure is put in place, will significantly add to the US gas supplies and will thus weigh on gas prices.

### D. The Outlook for US Shale Gas Production

The above points to a continued growth in the US shale gas production, at least until 2020. Steep decline curves and low gas costs will temper the production of most shale gas fields, even in the short term. But the Marcellus, Eagle Ford and Bakken plays are large and show attractive economics since they also produce NGLs and condensates. Marcellus and Eagle Ford are also connected to pipeline infrastructure (by-product gas from the Bakken tight oil wells is mostly flared). The prognosis for the top nine shale gas plays in the US, which accounted for 95% of US shale gas production as of mid-2012, is shown in the Table below.

<table>
<thead>
<tr>
<th>Field</th>
<th>Rank</th>
<th>Number of Wells needed annually to offset decline</th>
<th>Wells Added for most recent Year</th>
<th>October 2012 Rig Count</th>
<th>Prognosis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Haynesville</td>
<td>1</td>
<td>774</td>
<td>810</td>
<td>80</td>
<td>Decline</td>
</tr>
<tr>
<td>Barnett</td>
<td>2</td>
<td>1507</td>
<td>1112</td>
<td>42</td>
<td>Decline</td>
</tr>
<tr>
<td>Marcellus</td>
<td>3</td>
<td>561</td>
<td>1244</td>
<td>110</td>
<td>Growth</td>
</tr>
<tr>
<td>Fayetteville</td>
<td>4</td>
<td>707</td>
<td>679</td>
<td>15</td>
<td>Decline</td>
</tr>
<tr>
<td>Eagle Ford</td>
<td>5</td>
<td>945</td>
<td>1983</td>
<td>274</td>
<td>Growth</td>
</tr>
<tr>
<td>Woodford</td>
<td>6</td>
<td>222</td>
<td>170</td>
<td>61</td>
<td>Decline</td>
</tr>
<tr>
<td>Granite Wash</td>
<td>7</td>
<td>239</td>
<td>205</td>
<td>N/A</td>
<td>Decline</td>
</tr>
<tr>
<td>Bakken</td>
<td>8</td>
<td>699</td>
<td>1500</td>
<td>186</td>
<td>Growth</td>
</tr>
<tr>
<td>Niobrara</td>
<td>9</td>
<td>1111</td>
<td>1178</td>
<td>~60</td>
<td>Flat</td>
</tr>
</tbody>
</table>

**Source:** J. David Hughes, Post Carbon Institute, February 2013

This Table shows that the numbers of rigs and wells recently drilled in most plays are below what is needed to keep late 2011 production levels. Only Marcellus, Eagle Ford and Bakken attract the investments necessary for production growth. Note that, as discussed above, Marcellus and Eagle Ford are young plays, with much upside potential, in particular in Marcellus. With tight oil production in the Bakken possibly declining steeply after 2017, it is not yet clear whether most of the gas produced in Bakken will actually be fed in the US gas pipeline systems, or will simply continue to be flared.
As for tight oil, many industry experts affirm that advances in the understanding of the micro-geology of the fields and in drilling and fracking technology will significantly improve the economics of shale gas production in the US. They thus foresee a continued long-term growth of shale gas production in all fields, even if gas prices stay in the US$3-4 per million BTU range.

In its “2013 Annual Energy Outlook”, the US EIA projects US shale gas production to grow from 21.5 bcf/d in 2011 (34% of all US gas production), to 35.2 billion in 2025, and 45.8 billion in 2040 (50% of all US gas production). It estimates gas production from tight oil plays to grow from 16.0 bcf/d in 2011 (25% of US gas production) to 20.1 bcf/d in 2040 (22% of all US gas production).

**US Gas Production – 1990-2040**

(Trillion cubic feet)

![US Gas Production Graph](Image)

*Source: US EIA - Annual Energy Outlook 2013*

In all, the US EIA foresees that US shale gas and tight gas production will grow 75% in the next 30 years, from a combined 37.6 bcf/d in 2011 (60% of the US total gas production) to 65.9 bcf/d in 2040 (73% of the US total gas production). It foresees US gas production from all other US sources (onshore, offshore, associated gas, and coalbed methane) basically to remain at its 2011 levels.

As for tight oil in Section VII above, we have not seen the US EIA play-by-play detailed data supporting the above forecast. The US EIA also warns that its projections are “highly uncertain and will remain so until they are extensively tested with production wells.”
This is in particular the case as the continued growth of shale gas production will likely be driven by small / medium size players who have lower costs, are more agile and benefit more from small/short production wells – but are less predictable - than the majors (see Shell’s recent announcement that it will sell its position in Eagle Ford because it “does not meet [its] global targets for materiality and scale”).

**US Shale Gas Production and Outlook - Conclusions**

1. US shale gas production has grown rapidly to account for about 40% of US natural gas production. If one adds the gas produced from tight oil wells, about 63% of US natural gas production is expected to come from tight oil and shale formations in 2013.

2. As for tight oil formations, a few plays account for the majority of gas production: three out of thirty plays provide 66% of the total shale gas production (the next three provide another 22%). As for tight oil wells also, there is great variability in the wells’ production in different locations of the plays, even at relatively short distances. Apart from in the Marcellus and Eagle Ford, most of the “sweet spots” of the plays have been exploited.

3. Shale gas well decline rates are very steep, ranging from 79 to 95 percent after 36 months. This implies that about 50% of production must be replaced annually to maintain production. In some areas of the Marcellus however, operators report higher productivity and flatter decline curves than in other plays.

4. The rapid supply increase has depressed natural gas prices in the US to about US$3.8 / million BTUs. At this price, drilling shale wells is uneconomic, except when they produce meaningful volumes of NGLs. Once the inventory of drilled-but-not-yet-in-production wells is worked off, shale gas production will rapidly decline for dry plays.

5. The exceptions are the Marcellus and Eagle Ford plays which produce significant quantities of NGLs. Both Marcellus and Eagle Ford are large basins, already with adequate infrastructure to treat the gas, collect it and transport it to consumption centers. Their continued sustained pace of drilling and increased production will likely keep pressure on gas prices and will constrain the activities in other plays.

6. As for tight oil, we note however that the estimates published by most industry observers and official institutions (including the IEA and the US EIA) are for US shale gas production to keep increasing and remain at high levels for the long-term. Whilst many reputable and knowledgeable industry players affirm that technological advances and better understanding of the micro-geology of the formations will allow for significantly cheaper and longer-lasting dry shale gas production, we have not found detailed justifications for such assertions in the technical press.

7. We conclude by agreeing that shale gas production in the US will continue to grow at Marcellus and Eagle Ford, the two key large shale basins which offer attractive economics. Today, we have **no basis however to judge that US shale gas production will increase to, and remain at, the high levels estimated by most commentators and institutions, including the IEA and the US EIA**.
E. The Outlook for International Shale Gas Production

As for tight oil, and in addition to the significant resources deployed to find and develop on-shore and off-shore conventional gas fields, there is much activity around the world to find, assess and prepare the development of shale gas resources. The largest opportunities for future shale gas production are reported to reside in China, Argentina, Mexico, Algeria and Australia. Geology is also reportedly promising in Poland, France and Britain. Most observers assume that shale gas deposits also exist in the Middle East – in particular in Saudi Arabia – but they question whether these could be developed at a profit given the low gas prices prevailing there. The paragraphs below discuss the current state of knowledge and prospects for shale gas developments for the countries with the most likely attractive resource base.

1. China. China is believed to have the largest shale gas resources in the world, surpassing even those of the United States. Estimates published in May 2013 by the US EIA were for as much as 1,115 trillion cubic feet (tcf) of technically recoverable shale gas in seven basins (Sichuan, Tarim, Junggar, Songliao, the Yangtze Platform, Jianghan and Subei). The largest and most promising basins are in Sichuan a highly populated area in the middle of the country, with about 56% of the total estimated resource, and in Tarim, a more isolated (water-poor) basin in China’s western-most region, near Kyrgyzstan, with another about 20% of the total estimated resource.

The government is investing heavily to boost production as high as 5.8 bcf/d in 2020. Through subsidies and the promise of the exploitation of large reserves, many companies, including local state-owned coal and utility companies and government entities with no expertise in oil & gas exploration, have commenced resource definition work, in the Sichuan Basin in particular.

Expectations have however been tampered a bit this year, since initial wells have confirmed that some formations have a high clay content which makes them more pliable and less apt to fracture, and most are significantly deeper than in the US and possibly prone to high underground stresses which deform well casing.

Indeed, recent public comments by Chevron’s executives point to a possible considerable reduction in the estimates of China’s shale gas potential.

Also, in addition to complex geological hurdles, Shell and its partner China National Petroleum Corp. have recently reported facing significant “above ground” challenges as they tried to conduct their early drilling campaign in their Moaba site in Sichuan. Specifically, as they drilled in heavily populated and farmed areas - areas with yet inadequate power and road infrastructure – they not only had to invest heavily in the local power, transport and water infrastructure, but they also had to shrink the size of their drilling pad which reduced the number of wells they could drill from a single site. Villagers also protested on noise, dust and water pollution (which, given its extensive investments to control water effluents discharges, Shell did not believe was caused by its operators). Finally, with additional government requests to halt operations under complex local regulations, many days were lost and the exploration campaign has been much more expensive than initially thought. Shell officials pointed out recently that their China exploration / development program is its early stages and that it is much too early to presume that they may not proceed, on schedule, with the heavy shale gas investments they anticipate for China.

In any event, we believe that significant additional field results will be needed before China’s economically recoverable shale gas reserves can be estimated at the levels surmised to date.
2. **Argentina.** Argentina is reported to have large and high quality hydrocarbon shale formations, possibly the most prospective outside of North America, primarily within the Neuquen Basin. Some commentators see the Vaca Muerta field in Neuquen as the world’s second-largest deposit of recoverable shale gas.

The May 2013 US EIA report estimates Argentina’s economically recoverable gas resources at 802 trillion cubic feet (in addition to 27 billion barrels of tight oil) and ranks it the second largest holder of shale gas resources after China (and the fourth largest holder of tight oil resources). Argentina’s formations appear much simpler to exploit than those found in China, and they are in an area of the country in which oil has already been quite successfully produced.

In spite of political risk concerns stemming from Argentina’s 2012 expropriation of Repsol and from its dispute with the foreign holders of its sovereign bonds, major oil companies appear eager to try and develop significant oil & gas exploration and production facilities in the Vaca Muerta shale formation.

For instance, Chevron signed an agreement with YPF (Argentina’s oil company) in July this year, for a US$1.2 billion exploration and development program in the Loma La Lata Norte and Loma Campaña areas of Vaca Muerta. Press reports also mention that CNOOC, China’s oil company, is to enter before end 2013 in an agreement with YPF to develop other deposits in Vaca Muerta. ExxonMobil, Total, Shell, Petrobras, BP and Dow Chemicals, in addition to several mid-size oil companies, either already have exploration rights in Vaca Muerta or are also in discussions to acquire such rights.

It thus looks like Argentina is likely to develop a sizeable shale gas industry in the years to come, perhaps faster than currently envisaged. Forthcoming results of pre-development wells will indicate whether Argentina will also produce large amounts of shale oil.

3. **Australia.** Australia’s potential shale gas resources are estimated at 437 tcf. These resources are in remote basins, but basins with both existing infrastructure – such as the Central Cooper Basin – and long histories of oil & gas production. Existing or easy-to-build pipelines would in fact allow this gas to flow to Queensland and be fed in existing or expanded LNG export plants (Australia is one of the world’s largest LNG exporters, and has been for decades). The major oil companies are familiar with the Australian legal and fiscal systems and several of them (Chevron, ConocoPhilips, Total) have recently initiated exploration ventures. We believe it too early to comment on the extent and timing of Australia’s shale gas production.

4. **Mexico.** Mexico should offer excellent prospects for tight oil and shale gas production. The US EIA estimates technically recoverable shale resources at 545 tcf for natural gas and 13.1 billion barrels for oil and condensates. This is potentially larger than the country’s proven conventional reserves, and ranks Mexico sixth for the world’s shale gas reserves. The best documented play is Eagle Ford, where oil- and gas-prone windows extending south from Texas into northern Mexico have an estimated 343 tcf and 6.3 billion barrels of recoverable shale gas and shale oil resource potential.

PEMEX plans to initiate commercial shale gas production in 2015 and expects to increase it to around 2 bcf/d by 2025, with the company potentially investing $1 billion to drill 750 wells. However, PEMEX’s initial shale exploration wells have reportedly been costly ($20 to $25 million per well) and have provided only modest initial flow rates with steep declines.

Mexico’s potential development of its shale gas and shale oil resources may be constrained by several factors such as PEMEX’s focus on large conventional oil plays,
limitations on JVs with foreign partners, limited capabilities of the local oil-services sector and public security concerns in many shale areas.

5. **Algeria**. In addition to its reserves of conventional oil, Algeria is reported to have large and a-priori attractive shale formations. The US EAI estimated in May 2013 that Algeria has 707 tcf of technically recoverable shale gas in seven basins. The most attractive of these basins are in the South of the country, presumably far from water resources. Yet, several international oil companies such as ExxonMobil, ENI and Shell are reported to have expressed interest in conducting exploration campaigns in these formations. With its share of the LNG export markets slumping a bit and production from its conventional reserves plateauing, the government is also reported to relax the tax regime to attract foreign investors.

Overall, we believe that the extent and speed at which Algeria will develop its shale gas production will be clearer once the initial exploration wells confirm the attractiveness of the formations and once the government finalizes its policies to attract foreign investors.

6. **Poland**. With a-priori attractive geological formations (the US EIA estimates recoverable shale gas resources at 146 tcf in several basins) and a favorable infrastructure and public support for shale development, Poland has attracted numerous shale gas exploration investments for several years now. The government has issued more than 100 shale gas exploration licenses to local and international firms, which had drilled 48 wells by mid-2013. Early results did not meet the industry’s high initial expectations, and ExxonMobil, Marathon and Talisman had abandoned their exploration programs by early 2013.

Results from new test wells last month have however been more positive, with the press reporting actual shale gas production in a test well controlled by ConocoPhillips. It remains to be seen whether these developments and the hope-for decreases in drilling costs will usher a sizeable commercial production of shale gas in Poland.

7. **England**. The United Kingdom has substantial volumes of prospective shale gas and shale oil resources. Preliminary estimates point to possible resources of 134 tcf and 17 billion barrels of shale oil, but these are in geologically complex formations. Shale testing is at a very early stage, and it is too early to judge whether the production of shale gas from the promising formations can be technically possible and economically attractive. Further, and as mentioned in Section VIII above, the initial reaction of the local population has been quite negative, so that the development of substantial shale gas production in England it does not appear likely in the medium-term.

8. **France**. France is reported to possess attractive shale gas formations in large basins around Paris and Marseille. The US EIA reports that these may hold up to 129 tcf of recoverable shale gas resources. There is strong political opposition in France even to drill exploration and confirmation wells to ascertain the existence of such hydrocarbon-bearing shales. Commercial exploitation of these shales is unlikely for the foreseeable future.
Outlook for International Shale Gas Production - Conclusions

1. Most commentators have reported for a bright outlook for shale gas production outside the US. The US EIA in particular significantly increased in May this year its estimates of technically recoverable gas resources from international shale formations.

2. Our review of the bases for these estimates lead us however to conclude that the outlook for international shale gas (and shale oil) production may not be as promising as anticipated. There are two major reasons for our caution on this consensus.

3. First, as the US EIA itself points out, the geology of the shale basins is not as well understood as that of the US, and the productivity of shale wells cannot be forecast without actual production results and sophisticated well drilling and management adjustments to the local conditions.

4. And second, most importantly, “above ground” factors will likely be much less favorable for international basins than in the US.

5. Indeed, recent reports have cast doubts on the feasibility of extracting shale gas economically in China. Whilst Argentina and Australia reportedly offer good geological prospects and a-priori favorable “above ground” factors, any production there is likely years away. Above ground factors in Mexico, England and France seem to preclude the exploitation of shale formations for the foreseeable future. Initial production tests in Poland were inconclusive, in particular as drilling costs may be too high to justify developing the fields.

At this point thus, we doubt that international shale gas (and oil) production will grow as rapidly as most observers foresee. We note however that several large conventional gas fields in Africa, Eurasia and the Middle East may instead be developed to help meet long-term global gas demand.
X. IMPACT ON THE REFINING AND PETROCHEMICALS INDUSTRIES

A. US Tight Oil Production and Downstream Refining

With about 2.3 million barrels per day, tight oil accounts now for about 35% of the US oil production (up from less than 5% in 2008). By nature, tight oil is light and sweet (it contains little sulphur), and it is quite different from the heavy and sour crudes which, over the years, the US refineries have been designed to process. Indeed, a significant part of the US oil imports have to date been heavy and sour crudes from Venezuela, Mexico, Canada (in particular from super heavy bitumen from oil sands) and from the Middle East.

Some crudes, such as that from Saudi Arabia, are destined to be processed directly into specially designed refineries. The others are often blended with lighter WTI or Brent, and, depending upon (i) the price differentials between light and heavy crudes, (ii) the difference in yields (light crudes yield more high value gasoline), and (iii) the relative prices of the refined product themselves (fuel oil, vs. gasoline, vs. diesel), refiners optimize the feedstock mix and the processing configuration of their plants to maximize their returns.

With the rapid increase in light tight oil production, industry observers noted the a-priori mismatch between the composition of the crude which the US refineries increasingly have to process, and their basic technical configuration (by law, US crude cannot be exported, so tight oil is to be processed domestically).

At this point, it appears that the US refining industry should be able to adapt to this increasingly different crude supply situation without too much difficulties, for the following four reasons.

First, relatively inexpensive adjustments to the existing refineries or to the way they are run will in fact allow the effective processing of lighter and sweeter feedstock (which would not be the case the other way around, from processing sweet to processing heavy crudes). Some refineries may simply not run their feedstock stream through their coker for instance; others, depending upon the units they already have, may build relatively inexpensive plants such as hydroskimmers or pre-flash towers. Industry experts thus do not anticipate that the large increase in light sweet feedstock will have a major negative impact on the US refineries and their profitability.

Second, the US will simply import less “light crudes”. There will thus likely be a global relative surplus of light crudes, which should result in a narrowing of the light-heavy price differentials. It appears that the global oil markets are experiencing this and that the producers of light crudes (African in particular) and the importers of such crudes (European in particular) are adapting to this new reality. The global markets for both crudes and refined products are extremely efficient, and they will quickly adjust to reflect the relative scarcities and worth of crudes and downstream refined products (it will be interesting to see if, with a surplus of light sweet crudes, gasoline may become cheaper than diesel).

Third, the US is rapidly adapting its pipeline and blending infrastructure to the new flows of oil and liquids. This will both relieve bottlenecks and increase the value which producers may capture from their fields. For instance, Sunoco has recently announced plans to convert part of its refined products pipeline system in Texas to crude transportation.
Sunoco will also reverse the direction of flow of another pipeline to bring crude from tight oil plays in east Texas to its Beaumont / Port Arthur refining complex in southeast Texas. Several oil terminal and trading companies have announced plans to build or outfit more tanks in their US sites to blend tight oil with heavier crudes.

And fourth, several companies are setting up blending and logistics operations to mix heavy Canadian crude with condensates and NGLs by-products of the nearby Bakken play, for easier transportation to and easier processing of their oil sands derived crude by the US refineries.

In all thus, with an already well developed infrastructure, transparent and dynamic crude and product pricings, and a unique capability to adapt rapidly to dramatically-changed crude supply conditions, we believe that the US energy industry will comfortably restructure its operations as domestic tight oil production continues to rise.

**B. Shale Gas & NGLs Production and the Global Petrochemical Industry**

As discussed above, US tight oil wells (in Eagle Ford for instance) and shale gas wells (in Marcellus for instance) can produce NGLs - Marcellus’ gas production is reported to be 75% methane (natural gas) and the rest NGLs: 16% ethane, and 1% for propane, butane, hexane and other gases.

Depending upon storage and pipeline constraints, and depending upon the value which producers may realize for these liquids, the NGLs are either separated or left in the natural gas streams (there are safety constraints however on how much ethane can be fed in a methane distribution network). When separated, NGLs are piped to consumption centers, and, now even possibly to export centers (Marcellus shale propane is exported to Canada from Sunoco’s Pennsylvania facilities; Nova (Canada) and Ineos (Europe) entered last year into agreements to import Marcellus shale ethane to feed their crackers with new pipeline and ocean shipping infrastructure).

NGLs production from shale wells grew from 1.8 million bpd in 2008 to reach 2.3 million bpd this year, and increase of 34% in the five years. With the continued expected growth in wet shale gas production, the industry expects production of NGLs to increase by another 34% to 3.1 million bpd in 2016.

This abundant new supply of cheap ethane, propane and butane, as well as of heavier condensates, is seen as propelling again the US petrochemical industry towards a uniquely-advantaged position when compared to producers from Europe, Asia and even the Middle East. Over the years, and to produce ethylene (ethylene is the key petrochemical building block), US olefins / thermoplastics producers have built and operated with great efficiency (i) ethane crackers with significant flexibility to process various NGLs feedstocks, and (ii) naphtha crackers with a more diversified output slate (propylene, butadiene, etc.). Indeed, whilst they predominantly process ethane, the US ethane crackers can usually also process some propane, butane, condensates (or a mix), as economics best dictate. Ethylene production in the US – and thus by inference the whole petrochemical industry – is thus characterized by a great flexibility to process various feedstocks and capture the highest margins, depending on the relative values of ethane, NGLs and naphtha (the price of which is linked to oil prices).

Most crackers in the Middle East do not have that flexibility since they are designed to process only ethane; neither do the European and Asian crackers since they are designed to process only naphtha.
Over the last decades, the Middle East petrochemical industry benefited from cheap ethane and posted very attractive margins; the European industry remained profitable by optimizing the value it recovers from the more diverse product streams from its naphtha crackers; and the Asian industry benefited from its proximity to fast growing markets. Recently, large petrochemical capacity was added to world-class refineries to benefit from synergies between crude refining and petrochemical manufacture.

With continued rapid supply growth, US ethane and NGLs prices expected to remain low for the foreseeable future. With high expectations for enduringly attractive margins to produce ethylene, several large players, American firms and international firms as well, have announced plans to expand their plants or build new ethane-based ethylene crackers in the US.

As of mid-2013, these plans amount to adding about 10 million tonne per year capacity, which would increase the US ethylene capacity by 40%, and the world’s by 7%. The exact timing of these projects remains uncertain since they and their pipeline links to the fields will need to be built in time just as shale ethane becomes available, and is judged so available on a long term sustainable basis.

**Proposed US Ethylene Capacity Additions – 2013-2020**

<table>
<thead>
<tr>
<th>Company</th>
<th>Location</th>
<th>Proposed capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chevron Phillips</td>
<td>Baytown, TX</td>
<td>1.5</td>
</tr>
<tr>
<td>Exxon Mobil</td>
<td>Baytown, TX</td>
<td>1.5</td>
</tr>
<tr>
<td>Sasol</td>
<td>Lake Charles, LA</td>
<td>1.4</td>
</tr>
<tr>
<td>Dow</td>
<td>Freeport, TX</td>
<td>1.4</td>
</tr>
<tr>
<td>Shell</td>
<td>Beaver Co, PA</td>
<td>1.3</td>
</tr>
<tr>
<td>Formosa</td>
<td>Point Comfort, TX</td>
<td>0.8</td>
</tr>
<tr>
<td>Occidental/Mexichem</td>
<td>Ingleside, TX</td>
<td>0.5</td>
</tr>
<tr>
<td>Dow</td>
<td>St. Charles, LA</td>
<td>0.4</td>
</tr>
<tr>
<td>LyondellBasell</td>
<td>Laporte, TX</td>
<td>0.4</td>
</tr>
<tr>
<td>Aither Chemicals</td>
<td>Kanawha, WV</td>
<td>0.3</td>
</tr>
<tr>
<td>Williams/Sabic JV</td>
<td>Geismar, LA</td>
<td>0.2</td>
</tr>
<tr>
<td>Ineos</td>
<td>Alvin, TX</td>
<td>0.2</td>
</tr>
<tr>
<td>Westlake</td>
<td>Lake Charles, LA</td>
<td>0.2</td>
</tr>
<tr>
<td>Williams/Sabic JV</td>
<td>Geismar, LA</td>
<td>0.1</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>10.1</strong></td>
</tr>
</tbody>
</table>

*Source: US EIA – Annual Energy Outlook, 2013*

This substantial increase in US ethylene capacity is to take place as considerable capacity additions are also planned in Asia and the Middle East. These additions will be driven by (i) the availability of cheap gas in some specific situations (Abu Dhabi), (ii) the integration with very large new refining complexes (Saudi Arabia, India and China), and (iii) the proximity to fast growing markets.

Most industry observers thus surmise that, whilst massive, this increase in US ethylene capacity from tight oil and shale gas will in fact primarily be a regional phenomenon, with additional exports to Latin America and renewed pressure on European crackers, and that it will merely contribute to - not cause - a likely severe tightening of global ethylene margins and, indirectly, an increased pressure on European and Asian naphtha crackers.
C. Impact on Saudi Arabia’s Petrochemical Industry

We believe that the major impact which the increase in US shale gas based ethylene capacity will have on Saudi Arabia’s petrochemical industry will be this contribution to a tightening of margins and some reduction the competitive advantage which Saudi’s producers derive from cheap feedstock.

With no reported additional potential supply of cheap ethane, future Saudi petrochemical complexes will most likely be built as part of large refining complexes. As it seeks to continue to grow and to diversify its asset base, SABIC will consider investing in US shale ethane and NGL projects.

Conclusions

1. The US refining industry will likely adapt well to the lighter and sweeter crude slate it will henceforth have to process from the country’s tight oil plays. Canadian oil sands producers, European refiners and African light crude producers will most suffer from the narrowing of the light-heavy price differential.

2. We do not believe that the increase in US tight oil production will significantly impact Saudi Arabia’s oil receipts and the profitability of its refinery industry.

3. The US petrochemical industry will benefit greatly from the increased production of cheap ethane and NGLs by-products from tight oil and shale gas production. Significant new capacity will be built in the US, including by European and Middle East firms which will seek access to low cost feedstock.

4. This increase in low-cost ethylene capacity in the US, along with the capacity build-up already committed in Asia, will reduce the profitability of Saudi Arabia’s petrochemical industry.
XI. DEEP-WATER, OIL SANDS & EXTRA HEAVY OIL

In addition to tight oil, there are three major other unconventional sources of oil which will impact the world’s energy industry in the next 30 years: deep-water reservoirs, oil sands and extra heavy oil deposits. A fourth one - kerogen oil (kerogen is organic material which has not yet been decomposed into oil but can yield oil upon heating) – is not discussed in this report since, whilst abundant, it will not likely be an economic source of oil in the next 40 years.

A. Prospects for Deep-water Oil Production

The industry has known for many years that large oil resources are found under the sea. In its 2012 World Energy Outlook report, the IEA estimated that offshore fields contain about 1,215 billion barrels of recoverable oil, 45% of the world’s remaining recoverable conventional oil. It expects that, of this, about 300 billion barrels (a quarter) are in deep-water fields, defined as water with a depth in excess of 400 meters. The map below shows where the most promising of these fields are.

IHS CERA reports that deep-water oil production almost doubled to about 5 million bpd between 2005 and 2010, and represented 6% of the world's 2010 total crude output. Obviously, the exploration for and the development of deep-water oil fields slowed after the April 2010 deep-water Horizon Macondo disaster and oil spill in the Gulf of Mexico.

Since then, regulators, oil companies and service companies have significantly tightened up the regulations and operational safety standards which the industry must follow. Deep-water investments and operations have by now regained momentum, and industry observers expect deep-water oil production to double again by 2020. Indeed, the industry
is not only actively exploring deep-see prospects in Brazil and the Gulf of Guinea, but also in new areas such as the Atlantic Ocean west of the Shetland Islands (Chevron), the Eastern Mediterranean (Noble) and the Turkish Black Sea (ExxonMobil and Chevron).

Deep-water offshore Brazil is in particular considered to offer very bright prospects for deep-water oil production. Petrobras has started to develop large fields in the Campos and Santos Basins, more than 250 kilometers off the country’s southeast coast. Whilst they are quite expensive to develop and operate (a well costs upwards of US$100 million and a rig rents for about US$700,000/day) and whilst they present significant technical challenges (depth and drilling through salt layers), these fields are expected to account for the majority of Brazil’s projected production growth, contributing 2.9 additional million bpd by 2020 and 4.4 million bpd by 2035. The press recently reported significant new discoveries in these fields (Libra in the Santos Basin is said to contain possibly 8 billion barrels of recoverable oil) and in new fields offshore the northern state of Sergipe. In spite of the cost to develop and exploit these fields (Petrobras alone had planned to invest more than US$60 billion there between 2012 and 2016), international oil companies have shown interest to partner with Petrobras to access these large long-life reserves.

The IEA projects the contribution of offshore fields to global crude oil production to remain relatively stable to 2035. Deep-water production expands from 4.8 million bpd in 2011 to about 8.7 million bpd by 2035, offsetting a decline in shallow-water production (mainly in the North Sea and the Gulf of Mexico). The expansion of output from deep-water fields will be driven mainly by new developments in Brazil, West Africa and the US part of the Gulf of Mexico. Most large international oil companies have active exploration programs in deep-water fields and expect deep-water oil to provide a significant proportion of their production for years to come.

**World Offshore Crude Oil Production – 2005-2035**

![World Offshore Crude Oil Production Chart](chart.png)

*Source: IEA - World Energy Outlook 2012*

**B. Oil Sands**

As discussed in Section III, the mining of oil sands or bitumen from Alberta (Canada) has developed into a large industry over the last 30 years. In 2011, 600 million barrels of oil from these mines was exported to the US, contributing to about 14% of the US oil imports.
The mining of these oil sands is expensive (between US$60 and US$90 per barrel). The output, bitumen, is a very heavy oil which is either (i) diluted with NGLs and exported as heavy crude feedstock to US Gulf Coast refineries, or (ii) upgraded into light crude near the mines, also for (higher value) export to downstream refineries.

Canada’s National Energy Board estimates oil sands resources at 174 billion barrels, and, until the development of tight oil production in the US, production of oil sands was expected to grow and increasingly to contribute to the supply of crude to US refineries. Indeed, major investments in upgrading complexes – each costing in the US$10-15 billion range – were planned to increase the export attractiveness of the mines’ output and capture some of the large (up to US$40 per barrel) price differential between Canadian bitumen and light crudes.

The rapid expansion in US tight oil production has had a major negative impact on Canadian oil sands production.

First, as discussed above, the increase in US light oil supply from tight oil formations has significantly reduced the light-over-heavy premium upon which the Canadian oil sands upgrading complexes were justified. With such premium at only US$10 per barrel now, observers assume that these complexes will not be built.

Second, the dramatic expansion of light tight oil production from the Bakken field in North Dakota and Montana has taken up all the pipeline capacity which used to transport Canadian diluted bitumen to the US Gulf Coast refineries (in fact, there is no enough pipeline capacity, and substantial volumes of Bakken’s oil is shipped by rail). So, the transport logistics and cost of heavy Canadian material have become so complex and expensive as potentially to cripple the economics of the oil sands industry – hence the Canadian government’s strong push for the US to build the Keystone pipeline.
In all, production from Alberta’s oil sands field is expensive and for the moment at least, hampered by a lack of transport capacity to the downstream refineries interested in such heavy feedstock. To remain an attractive source of oil, Canada’s oil sands deposits will need that oil prices remain high and that adequate infrastructure be built for economic export.

Since, in addition, the mining of oil sands has significant environmental impacts (CO$_2$ and water contaminants), we believe that oil sands will be the “unconventional source of oil” most at risk of slowed down development.

C. Extra Heavy Oil

A major portion of the world’s known remaining technically recoverable oil resources is in extra heavy oil deposits. Oil from these deposits is too viscous to extract by simple conventional technology. The industry has already succeeded in markedly improving the recoveries, in particular with steam injection, so that production is economic at current prices in some of these fields. Significant efforts are under way to develop more efficient and economic ways to extract the oil from such deposits. As an example, the specific development of the Wafra Field in the Saudi Arabia-Kuwait Neutral Zone is discussed below.

In its World Energy Outlook 2012 report, the IEA estimates that about 1,700 billion barrels of extra heavy oil can be technically recovered worldwide. This is about 80% of the estimated recoverable resources of unconventional sources (including tight oil and oil sands) and 35% of the estimated recoverable oil resources, conventional and unconventional.

Resources of Heavy Oil by Regions

Source: US Geological Survey
As of today, a large portion of these resources cannot be recovered economically with existing technology. It will be the interplay between oil prices, technology developments and above ground factors which will determine how much of these resources will be exploited and how fast.

**Venezuela.** At this point, most of the world’s extra heavy oil is produced from the Orinoco belt in Venezuela. PDVSA and international companies started to invest 20 years ago in Orinoco production wells, pipeline infrastructure, upgraders, etc. With Venezuela’s political situation (the stakes of initial operators were either nationalized or significantly reduced) growth has however been quite below initial hopes. Even the four existing upgraders where the heavy oil is converted into lighter sweeter crude are reported to produce less than 500,000 bpd, 20% below nameplate capacity. The industry doubts that PDVA’s ambitious plans to develop additional projects for 2 million bpd capacity will soon be realized, as political uncertainties and above grounds issues continue to delay actual investments decisions.

Thus, even with the world’s second largest estimated proven reserves of oil, Venezuela’s contribution to the world’s oil supply may remain at, or slightly decline from, today’s levels. Most observers assume that, if the investment climate for foreign firms improves and if “above ground” issues are resolved, Venezuela’s production and export of upgraded crude from its extra heavy oil fields should materially add to the world’s oil supply by 2040.
AN EXTRA HEAVY OIL PROJECT: WAFRA IN THE SAUDI ARABIA-KUWAIT NEUTRAL ZONE

In the desert sands in the Neutral Zone across the Saudi Arabia / Kuwait border, a massive experiment has been ongoing since 2009 to determine whether heavy hard-to-extract oil can be economically recovered from the large, well-known and long-exploited Wafra Field.

Until now, in more than 50 years of production, traditional methods have only captured around 5 percent of the oil in place in Wafra Field’s “First Eocene” reservoir. Just an additional 1 percent recovery from this reservoir alone would add more than 100 million barrels to Wafra's reserves. The “First Eocene” reservoir holds an estimated 9 billion barrels of net oil, and additional resources are expected in the “Second Eocene” reservoir.

To get to Wafra’s thick oil, workers are injecting steam into the ground to heat the oil and make it less viscous, allowing it to flow to the surface. The technique, “steamflooding”, is tricky, expensive and unproven in the type of rock that holds Wafra’s oil. Chevron, which is experienced in developing heavy oil recovery technologies, is responsible for the project’s development.

To date, findings from the 16 steam-injection wells in the field and from the Large-Scale Steamflood Pilot plant have been encouraging. Full-field development would be the first commercial application of conventional steamflooding in a carbonate reservoir anywhere in world. The project would involve drilling some 10,000 producing, steam-injection and temperature-observation wells and installing large, standalone power and steam-generation facilities.

Final full scale project go-ahead had been expected by end 2013. Recently however, Chevron decided to carry on with its large-scale pilot tests to understand better the difficulties inherent in injecting steam into the field's carbonate reservoir to extract the heavy crude. A spokesperson recently declared that the front-end engineering design for Stage 1 of the Wafra steamflood project would commence in 2014. Stage 1 is expected to produce a maximum of 80,000 bpd, but it is not yet clear when Chevron plans to reach this target.

In the end, it will not be the presence of oil at Wafra which will determine whether taking the project to full-scale development is worth the massive investment; it is whether forward oil prices and the emerging technology will allow recovering that oil from Wafra economically.

D. Unconventional Oil and Global Recoverable Oil Resources

As technology progresses, new more-difficult-and-expensive-to-exploit oil resources may become commercially attractive, significantly increasing the energy resource base from which we will power our economies.
The table below summarizes the IEA’s estimate of total technically recoverable oil resources, for both conventional and unconventional sources, as published in World Energy Outlook 2012 report. Attachment 7 presents the IEA estimate in more detail. Note that we have amended their original data (i) to omit kerogen oil and (ii) to show deep-water oil under unconventional sources instead of conventional as they classify it.

### Global Technically Recoverable Liquids Resources
(As of end-2011, in billion barrels)

<table>
<thead>
<tr>
<th>Source</th>
<th>Conventional Liquids</th>
<th>Unconventional Liquids</th>
<th>Total</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Onshore</td>
<td>Conventional Offshore</td>
<td>Total</td>
<td></td>
</tr>
<tr>
<td></td>
<td>1,463</td>
<td>915</td>
<td>2,378</td>
<td>50%</td>
</tr>
<tr>
<td>Conventional Offshore</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td></td>
<td></td>
<td>100%</td>
</tr>
<tr>
<td>Deep-water Offshore</td>
<td>300</td>
<td></td>
<td>300</td>
<td>6%</td>
</tr>
<tr>
<td>Extra Heavy &amp; bitumen</td>
<td>1,881</td>
<td>239</td>
<td>2,120</td>
<td>44%</td>
</tr>
<tr>
<td>Tight &amp; shale oil</td>
<td>239</td>
<td></td>
<td>239</td>
<td>5%</td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td></td>
<td>2,420</td>
<td>50%</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td></td>
<td>4,798</td>
<td>100%</td>
</tr>
</tbody>
</table>

*Source: IEA – World Energy Outlook 2012; Jadwa Investment*

This table shows that extra heavy oil and bitumen deposits constitute the largest physical technically recoverable resources of oil (39% of total resources), followed by conventional onshore deposits (30%) and conventional offshore (19%).

The table also shows that, to-date, tight and shale oil are estimated to account for only 5% of the world’s technically recoverable liquids resources.

Note however that, as explained above, the actual exploitation of each resource will depend upon it economic attractiveness. We know in particular that most extra heavy oil / bitumen deposits are not economically exploitable currently, but that, conversely, numerous US tight and shale oil plays are attractive.

Thus, even though their absolute in-situ quantity may be much less than that of other sources, tight and shale oil plays are seen by all as important sources of oil and liquids for the short-/medium-term.
Conclusions

1. In spite of the massive investments which they require, deep-water fields will become an increasingly important source of oil in the short-/medium-term. Most large international companies expect deep-water oil to provide a significant portion of their liquids production for years to come.

2. In terms of physical quantities, oil sands, bitumen and extra heavy oil account for the largest share (39%) of the world’s technically recoverable oil resources. Yet, most deposits are not economically exploitable at current crude prices and the majority of observers believe that these fields will be developed only if oil prices climb to, and remain at, materially higher levels than those now prevailing.

3. Conversely, whilst representing to date only about 5% of the world’s total technically recoverable liquids resources, tight and shale oil deposits can be economically attractive, particularly in the US. Most observers thus assume that tight oil production will continue to increase somewhat in the US, and be initiated and possibly reach meaningful levels in Russia, Argentina and later on Libya.
XII. Tight Oil, Shale Gas & the Long-Term Global Energy Outlook

This report has reviewed the technical, economic and societal aspects of tight oil and shale gas production. Whilst it has focused on the achievements and prospects of such production in the US - where tight oil now supplies about 35% of the country's oil needs and shale gas 64% of its gas needs - this report has framed its analyses in the likely overall evolution of the global energy industry.

This Section summarizes the long-term outlook for global energy demand and the key impact which tight oil and shale gas production may have on the global supply of hydrocarbons to meet that demand.

This Section also highlights (i) the key issues which we believe will affect the development of tight oil and shale gas production, both in the US and globally, and (ii) our view as to the likely relative contribution of all conventional and unconventional sources of oil & gas to meet global energy demand.

A. Demand for Energy

The graph below - already shown in Section IV - presents ExxonMobil’s estimate of future energy demand. This estimate is very much in line with the projections published by other industry participants and official institutions.

GDP and Global Energy Demand – 2010-2040

[Graph showing GDP and Global Energy Demand]

Source: ExxonMobil – Outlook for Energy 2013
The key assumptions underpinning the above forecast (and that of most other industry and official observers) are (i) the continued high rate of GDP growth in Asia (specifically China and India), and (ii) the 35% reduction in the energy intensity of the world’s economy.

We are not convinced that Asia may continue to generate unabated for the next 25 years the high growth rates it has experienced in the last decade. On the other hand, we are not convinced either that forthcoming technology improvements will result in the large energy efficiency gains now postulated.

As these broadly balance out, we believe that the forecast presented above offers a good base for projecting the global energy demand which energy supplies will have to meet.

B. Oil & Gas Supply

1. Liquids

As discussed in Section IV, liquids (oil & NGLs) account for about a third of the energy which the world consumes. Demand for liquids is driven by transport and industrial activities (about 50% of oil is used in the transport sector and 35% in industry). Demand for liquids is forecast to grow from 4.5 trillion toe in 2010 to 5.6 trillion toe in 2040, a growth of 0.8% p.a. on average.

The graph below - already shown in Section IV - presents ExxonMobil’s estimate of future liquids supply, by sources of supply. This estimate is very much in line with the projections published by other industry participants and official institutions.

Global Supply of Liquids – 2010-2040

Source: ExxonMobil – Outlook for Energy 2013
The key assumptions underpinning the above forecast (and that of most other industry and official observers) are (i) the decline in the production of oil from conventional sources, (ii) the rapid growth of deep-water oil production, (iii) the continued growth of oil sands production, (iv) the continued growth of tight oil production in the US and internationally, and (v) the rapid growth in NGLs production from tight oil and shale gas fields.

As explained in Sections VII and VIII, we are not convinced that tight oil (and NGLs) production will actually grow as most observers surmise. This is both because (i) well decline rates in the two key plays (Bakken and Eagle Ford) are very steep and US production may taper off after 2017, and because (ii) the development of now-believed promising basins in Russia and Argentina may not be as easy and economically attractive as currently expected, in particular for “above ground” issues.

Yet, even though we doubt that tight and shale oil production will grow as most commentators forecast, we believe that the industry will reasonably comfortably produce enough liquids to meet long-term demand, and this for two reasons.

First, tight oil production will keep representing only about 3% of total liquids supply, so a smaller production of tight oil will not seriously affect global oil markets.

And second deep-water production may actually be larger than now assumed. Further, additional supplies will likely be forthcoming from extra-heavy oil and oil sands if oil prices rise above their current levels.
2. Gas

As discussed in Section IV, gas now accounts for 22% of the energy which the world consumes. Electricity generation, industrial activities and residential uses drive gas demand (about 39% of gas is used for electricity, 37% in industry, and 22% for residential uses). Demand for gas is forecast to grow rapidly from 2.9 trillion toe in 2010 to 4.8 trillion toe in 2040, a growth of 1.7% p.a. on average.

The graph below - already shown in Section IV - presents ExxonMobil's estimate of future gas supply, by sources of supply. This estimate is very much in line with the projections published by other industry participants and official institutions.

**Global Natural Gas Supply – 2010-2040**

*Source:* ExxonMobil – Outlook for Energy 2013

The key assumptions underpinning the above forecast (and that of most other industry and official observers) are:

- (i) A decline in conventional gas production in North America;
- (ii) The rapid growth of conventional gas production in Eurasia, Africa and the Middle East;
- (iii) The continued growth of shale gas production in the US to about 2027, plateauing thereafter; and,
(iv) The development of substantial shale gas production in China, Argentina, Australia, Mexico, Algeria and Europe.

As explained in Section IX, we are not convinced that shale gas production will actually grow as rapidly as most observers surmise.

For the US, this is because, except at Marcellus and Eagle Ford, shale gas production is not attractive at current gas prices (US$3.75 / million BTU). Gas prices would have to increase to above US$5.00 / million BTU; advances in the understanding of the shales micro-geology, well drilling / management technology would have to flatten the wells decline curves significantly; and pipeline infrastructure would have to be built, to justify exploiting other shale plays for dry gas (i.e. gas without NGLs).

Marcellus and Eagle Ford are large basins with still-attractive geological upside, significant value uptake from the production of by-product NGLs, and already reasonably well-developed pipeline infrastructure to the gas consumption and NGLs processing centers. We thus believe that the continued growth in Marcellus and Eagle Ford production will weigh on US gas prices and restrain gas production growth in other basins. We also believe that the intrinsic economics of gas production at Marcellus and Eagle Ford will still revolve around steep decline curves, short-life wells, and thus reasonably capital-intensive operations for not-very-large production runs. This is conducive to the basins’ exploitation by nimble mid-size low-operating-cost companies, not large oil companies which require the higher and more stable returns which larger reservoirs can provide.

Internationally, this because the geology of the basins may prove more difficult to exploit than in the US, drilling and operating costs will likely be significantly higher than in the US, and societal factors may hinder the drilling and exploitation of shale reservoirs. It appears in particular that, barring unforeseen technological breakthroughs, China may not easily reach its ambitious shale gas production targets in the planned time frame, or possibly ever. Apart from Argentina and Australia which have well developed oil and gas industries and likely more promising shale basins, no countries offer obvious potential for large and rapid shale gas production.

Even though we doubt that shale gas production will keep growing as much and as rapidly as most commentators forecast, we believe that the industry will reasonably comfortably produce enough gas to meet long-term demand.

This is because, as for liquids, there will likely be enough conventional sources of gas which can be developed in Africa, Eurasia and the Middle East to compensate for a shortfall in shale gas production.

Further, were a long-term shortage of natural gas to develop, gas prices will increase and more US shale deposits will be exploited. In that respect, the emergence of a deeper international LNG/gas trade will increase the rationale for developing hitherto “stranded” gas resources, in the US and elsewhere.
XIII. THE IMPACT OF TIGHT OIL & SHALE GAS ON SAUDI ARABIA

A. Oil

Since we doubt that tight oil production will grow as much as most commentators surmise, and since we believe that tight oil production will keep representing only about 3% of total liquids supply, we do not believe that the growth in oil production from tight rock formations in the US, or from shale formations elsewhere, will materially affect Saudi Arabia’s long-term position in the oil industry.

Clearly, as (cheaper) conventional sources of oil are depleted, the production of oil from (more expensive) unconventional sources will grow and will contribute an increasingly important percentage of the oil and NGLs needed to meet the world’s liquids demand.

We believe that deep-water and heavy-oil sources (whether oil sands in Canada, or extra-heavy crude in Venezuela and elsewhere - including Saudi Arabia) (i) will in fact be developed as technology and oil prices justify, and (ii) will provide the majority of the unconventional sources of oil needed to meet the world’s liquids demand.

We view the production of tight oil in the US as mainly impacting Saudi Arabia through the narrowing of the price differential between heavy and light crudes. That narrowing may force a restructuring of downstream global refining activities, in particular in Europe, but should not affect Saudi Arabia’s refining complexes.

We thus remain of the opinion that the key factor that will impact Saudi Arabia’s long-term position in the world’s energy industry is the high, and growing, internal demand. As we have previously opined, we believe that high internal demand, spurred by low internal energy prices, will not only distort internal economic decisions, but will also, in the long-term, crowd out and reduce the income from Saudi Arabia’s oil exports.

B. Gas

As for tight oil, we doubt that the production of shale gas in the US and elsewhere will increase as much as most observers surmise.

Yet, we believe that the large production of cheap (by-product) NGLs from tight oil and shale gas formations will have a significant impact on the world’s petrochemical industry.

Saudi Arabia is not a large producer of natural gas (methane). Also, its production of cheap by-product NGLs, including ethane, for petrochemical production will remain somewhat limited.

We thus see the main impact of the US shale gas and cheap NGL production on Saudi Arabia as (i) reducing the comparative profitability of Saudi’s existing petrochemical complexes, and (ii) inducing Saudi petrochemical firms to consider expanding their capacity in the US to profit from abundant, cheap yet valuable, feedstock.
Attachment 1

Conversion Factors

The industry does not use units of volume, units of weight and units of energy in a consistent way across sources of energy.

Some observers and institutions use units from the metric system; some others use units derived from the British Imperial system. For the same source of energy, gas for instance, some institutions even use volume units (bcf) in some sections of their analysis, and energy units (BTU) in other sections.

Since:
(i) the intrinsic energy contents of various sources of energy vary greatly;
(ii) some sources of energy are solid (coal) whilst others are liquid (oil) and others gaseous (natural gas); and,
(iii) the densities (volume/weight relationships) of solid or liquid sources of energy vary depending upon their specific origin (light vs. heavy crudes for instance),

then, any analysis of global energy topics must carefully apply conversion factors properly to aggregate or compare energies from different sources.

Physics dictate the following conversion factors:
1. 1 cubic meter is 33.5 cubic feet
2. 1 barrel is 160 liters
3. 1 million (10^6) tonnes of oil equivalent contain 3.968 10^7 million BTUs
4. 1 quadrillion (10^{15}) BTUs are 25.20 million tonnes of oil equivalent
5. 1 thousand cubic feet of natural gas contains 1.023 million BTUs
6. 1 million tonnes of oil equivalent is 11,630 giga(10^9)watt-hour
7. 1 gigawatt-hour is 3,412 million BTUs

Note that 3 and 5 above allow for comparing, as oil and gas prices vary, the economic value of one unit of energy contained in oil to the economic value of that same unit of energy when contained in gas.

In the US, at today’s relative prices for oil and gas (US$100/bbl and US$3.75/million BTU, respectively), one unit of energy in gas costs only about 20% of what it costs in an oil-derived product.
## Forecast Breakdown of Global Energy Demand 2010-2040

<table>
<thead>
<tr>
<th>Regions</th>
<th>2010</th>
<th>2025</th>
<th>2040</th>
<th>Average Annual Change</th>
<th>2010-2025</th>
<th>2025-2040</th>
<th>2010-2040</th>
</tr>
</thead>
<tbody>
<tr>
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<td>730.8</td>
<td>1,108.8</td>
<td>1,537.2</td>
<td>2.5%</td>
<td>2.8%</td>
<td>2.2%</td>
<td>2.5%</td>
</tr>
<tr>
<td>Asia</td>
<td>5,065.2</td>
<td>7,257.6</td>
<td>7,938.0</td>
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<td>2.4%</td>
<td>0.6%</td>
<td>1.5%</td>
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<tr>
<td>Europe</td>
<td>2,066.4</td>
<td>2,066.4</td>
<td>1,940.4</td>
<td>-0.2%</td>
<td>0.0%</td>
<td>-0.4%</td>
<td>-0.2%</td>
</tr>
<tr>
<td>Latin America</td>
<td>655.2</td>
<td>907.2</td>
<td>1,134.0</td>
<td>1.5%</td>
<td>2.2%</td>
<td>1.5%</td>
<td>1.5%</td>
</tr>
<tr>
<td>Middle East</td>
<td>756.0</td>
<td>1,083.6</td>
<td>1,335.6</td>
<td>1.9%</td>
<td>2.4%</td>
<td>1.4%</td>
<td>1.9%</td>
</tr>
<tr>
<td>North America</td>
<td>2,872.8</td>
<td>2,923.2</td>
<td>2,797.2</td>
<td>-0.1%</td>
<td>0.1%</td>
<td>-0.3%</td>
<td>-0.1%</td>
</tr>
<tr>
<td>Russia/Caspian</td>
<td>1,058.4</td>
<td>1,134.0</td>
<td>1,083.6</td>
<td>0.1%</td>
<td>0.5%</td>
<td>-0.3%</td>
<td>0.1%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>13,204.8</td>
<td>16,480.8</td>
<td>17,766.0</td>
<td>1.0%</td>
<td>1.5%</td>
<td>0.5%</td>
<td>1.0%</td>
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</table>

<table>
<thead>
<tr>
<th>End Use</th>
<th>2010</th>
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<th>2040</th>
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<th>2010-2025</th>
<th>2025-2040</th>
<th>2010-2040</th>
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</thead>
<tbody>
<tr>
<td>Residential/Commercial¹</td>
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<td>2,293.2</td>
<td>2,192.4</td>
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<td>0.7%</td>
<td>-0.3%</td>
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<tr>
<td>Transportation¹</td>
<td>2,394.0</td>
<td>2,797.2</td>
<td>3,276.0</td>
<td>1.1%</td>
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<tr>
<td>Industrial¹</td>
<td>3,956.4</td>
<td>4,888.8</td>
<td>4,993.2</td>
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<td>0.1%</td>
<td>0.7%</td>
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<tr>
<td>Electricity²</td>
<td>4,788.0</td>
<td>6,501.6</td>
<td>7,358.4</td>
<td>1.4%</td>
<td>2.1%</td>
<td>0.8%</td>
<td>1.4%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>13,204.8</td>
<td>16,480.8</td>
<td>17,766.0</td>
<td>1.0%</td>
<td>1.5%</td>
<td>0.5%</td>
<td>1.0%</td>
</tr>
</tbody>
</table>

1: Net of electricity  
2: Including electricity for residential, transportation and industrial uses

<table>
<thead>
<tr>
<th>Source</th>
<th>2010</th>
<th>2025</th>
<th>2040</th>
<th>Average Annual Change</th>
<th>2010-2025</th>
<th>2025-2040</th>
<th>2010-2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>4,485.6</td>
<td>5,241.6</td>
<td>5,619.6</td>
<td>0.8%</td>
<td>1.0%</td>
<td>0.5%</td>
<td>0.8%</td>
</tr>
<tr>
<td>Gas</td>
<td>2,898.0</td>
<td>4,032.0</td>
<td>4,762.8</td>
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<td>1.1%</td>
<td>1.7%</td>
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<tr>
<td>Coal</td>
<td>3,376.8</td>
<td>3,931.2</td>
<td>3,301.2</td>
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<td>1.0%</td>
<td>-1.2%</td>
<td>-0.1%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>730.8</td>
<td>1,033.2</td>
<td>1,486.8</td>
<td>2.4%</td>
<td>2.3%</td>
<td>2.5%</td>
<td>2.4%</td>
</tr>
<tr>
<td>Biomass / waste</td>
<td>1,234.8</td>
<td>1,386.0</td>
<td>1,386.0</td>
<td>0.4%</td>
<td>0.8%</td>
<td>0.0%</td>
<td>0.4%</td>
</tr>
<tr>
<td>Hydro</td>
<td>302.4</td>
<td>403.2</td>
<td>478.8</td>
<td>1.5%</td>
<td>1.9%</td>
<td>1.2%</td>
<td>1.5%</td>
</tr>
<tr>
<td>Other Renewable</td>
<td>176.4</td>
<td>453.6</td>
<td>730.8</td>
<td>4.9%</td>
<td>6.5%</td>
<td>3.2%</td>
<td>4.9%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>13,204.8</td>
<td>16,480.8</td>
<td>17,766.0</td>
<td>1.0%</td>
<td>1.5%</td>
<td>0.5%</td>
<td>1.0%</td>
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<table>
<thead>
<tr>
<th>Source</th>
<th>2010</th>
<th>2025</th>
<th>2040</th>
<th>Average Annual Change</th>
<th>2010-2025</th>
<th>2025-2040</th>
<th>2010-2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>34%</td>
<td>32%</td>
<td>32%</td>
<td>32%</td>
<td>34%</td>
<td>32%</td>
<td>32%</td>
</tr>
<tr>
<td>Gas</td>
<td>22%</td>
<td>24%</td>
<td>27%</td>
<td>27%</td>
<td>22%</td>
<td>24%</td>
<td>27%</td>
</tr>
<tr>
<td>Coal</td>
<td>26%</td>
<td>24%</td>
<td>19%</td>
<td>19%</td>
<td>26%</td>
<td>24%</td>
<td>19%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>6%</td>
<td>6%</td>
<td>8%</td>
<td>8%</td>
<td>6%</td>
<td>6%</td>
<td>8%</td>
</tr>
<tr>
<td>Biomass / waste</td>
<td>9%</td>
<td>8%</td>
<td>8%</td>
<td>8%</td>
<td>9%</td>
<td>8%</td>
<td>8%</td>
</tr>
<tr>
<td>Hydro</td>
<td>2%</td>
<td>2%</td>
<td>3%</td>
<td>3%</td>
<td>2%</td>
<td>2%</td>
<td>3%</td>
</tr>
<tr>
<td>Other Renewable</td>
<td>1%</td>
<td>3%</td>
<td>4%</td>
<td>4%</td>
<td>1%</td>
<td>3%</td>
<td>4%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
</tr>
</tbody>
</table>

**Source:** ExxonMobil – Outlook for Energy, 2013; Jadwa Investment
## Outlook for Unconventional Oil & Gas Production

### Attachment 2

### Forecast Breakdown of Global Energy Demand 2010-2040

#### Residential /Commercial (in million toe)

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2025</th>
<th>2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
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<td>Gas</td>
<td>655.2</td>
<td>806.4</td>
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<td>Electricity</td>
<td>806.4</td>
<td>1,184.4</td>
<td>1,537.2</td>
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<tr>
<td>Biomass/Waste/Other</td>
<td>1,058.4</td>
<td>1,083.6</td>
<td>932.4</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>2,898.0</strong></td>
<td><strong>3,477.6</strong></td>
<td><strong>3,754.8</strong></td>
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#### Average Annual Change

<table>
<thead>
<tr>
<th>Year</th>
<th>2010-2025</th>
<th>2025-2040</th>
<th>2010-2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>0.4%</td>
<td>0.0%</td>
<td>0.2%</td>
</tr>
<tr>
<td>Gas</td>
<td>1.4%</td>
<td>0.6%</td>
<td>1.0%</td>
</tr>
<tr>
<td>Electricity</td>
<td>2.6%</td>
<td>1.8%</td>
<td>2.2%</td>
</tr>
<tr>
<td>Biomass/Waste/Other</td>
<td>0.2%</td>
<td>-1.0%</td>
<td>-0.4%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1.2%</strong></td>
<td><strong>0.5%</strong></td>
<td><strong>0.9%</strong></td>
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#### Distribution

<table>
<thead>
<tr>
<th>End Use</th>
<th>2010</th>
<th>2025</th>
<th>2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>13%</td>
<td>12%</td>
<td>11%</td>
</tr>
<tr>
<td>Gas</td>
<td>23%</td>
<td>23%</td>
<td>23%</td>
</tr>
<tr>
<td>Electricity</td>
<td>28%</td>
<td>34%</td>
<td>41%</td>
</tr>
<tr>
<td>Biomass/Waste/Other</td>
<td>37%</td>
<td>31%</td>
<td>25%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>100%</strong></td>
<td><strong>100%</strong></td>
<td><strong>100%</strong></td>
</tr>
</tbody>
</table>

#### Transport (in million toe)

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2025</th>
<th>2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>2,368.8</td>
<td>2,872.8</td>
<td>3,150.0</td>
</tr>
<tr>
<td>Other (incl. electricity)</td>
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<td><strong>Total</strong></td>
<td><strong>2,494.8</strong></td>
<td><strong>3,124.8</strong></td>
<td><strong>3,553.2</strong></td>
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</tbody>
</table>

#### Average Annual Change

<table>
<thead>
<tr>
<th>Year</th>
<th>2010-2025</th>
<th>2025-2040</th>
<th>2010-2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>1.3%</td>
<td>0.6%</td>
<td>1.0%</td>
</tr>
<tr>
<td>Gas</td>
<td>4.7%</td>
<td>3.2%</td>
<td>4.0%</td>
</tr>
<tr>
<td>Other (incl. electricity)</td>
<td>1.5%</td>
<td>0.9%</td>
<td>1.2%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1.5%</strong></td>
<td><strong>0.9%</strong></td>
<td><strong>1.2%</strong></td>
</tr>
</tbody>
</table>

#### Distribution

<table>
<thead>
<tr>
<th>End Use</th>
<th>2010</th>
<th>2025</th>
<th>2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>95%</td>
<td>92%</td>
<td>89%</td>
</tr>
<tr>
<td>Other (incl. electricity)</td>
<td>5%</td>
<td>8%</td>
<td>11%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>100%</strong></td>
<td><strong>100%</strong></td>
<td><strong>100%</strong></td>
</tr>
</tbody>
</table>

#### Industrial (in million toe)

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2025</th>
<th>2040</th>
</tr>
</thead>
<tbody>
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<td>Oil</td>
<td>1,461.6</td>
<td>1,764.0</td>
<td>1,890.0</td>
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<tr>
<td>Gas</td>
<td>1,083.6</td>
<td>1,461.6</td>
<td>1,713.6</td>
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<td>Electricity</td>
<td>756.0</td>
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<td>1,360.8</td>
</tr>
<tr>
<td>Coal/Other</td>
<td>1,411.2</td>
<td>1,638.0</td>
<td>1,386.0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>4,712.4</strong></td>
<td><strong>6,022.8</strong></td>
<td><strong>6,350.4</strong></td>
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</table>

#### Average Annual Change

<table>
<thead>
<tr>
<th>Year</th>
<th>2010-2025</th>
<th>2025-2040</th>
<th>2010-2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>1.3%</td>
<td>0.5%</td>
<td>0.9%</td>
</tr>
<tr>
<td>Gas</td>
<td>2.0%</td>
<td>1.1%</td>
<td>1.5%</td>
</tr>
<tr>
<td>Electricity</td>
<td>2.9%</td>
<td>1.1%</td>
<td>2.0%</td>
</tr>
<tr>
<td>Coal/Other</td>
<td>1.0%</td>
<td>-1.1%</td>
<td>-0.1%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1.6%</strong></td>
<td><strong>0.4%</strong></td>
<td><strong>1.0%</strong></td>
</tr>
</tbody>
</table>

#### Distribution

<table>
<thead>
<tr>
<th>End Use</th>
<th>2010</th>
<th>2025</th>
<th>2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>31%</td>
<td>25%</td>
<td>30%</td>
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<tr>
<td>Gas</td>
<td>23%</td>
<td>24%</td>
<td>27%</td>
</tr>
<tr>
<td>Electricity</td>
<td>16%</td>
<td>19%</td>
<td>21%</td>
</tr>
<tr>
<td>Coal/Other</td>
<td>30%</td>
<td>27%</td>
<td>22%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>100%</strong></td>
<td><strong>100%</strong></td>
<td><strong>100%</strong></td>
</tr>
</tbody>
</table>

#### Electricity (in million toe)

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2025</th>
<th>2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>277.2</td>
<td>201.6</td>
<td>176.4</td>
</tr>
<tr>
<td>Gas</td>
<td>1,159.2</td>
<td>1,764.0</td>
<td>2,167.2</td>
</tr>
<tr>
<td>Coal</td>
<td>2,167.2</td>
<td>2,570.4</td>
<td>2,394.0</td>
</tr>
<tr>
<td>Nuclear</td>
<td>680.4</td>
<td>1,058.4</td>
<td>1,486.8</td>
</tr>
<tr>
<td>Hydro</td>
<td>302.4</td>
<td>403.2</td>
<td>478.8</td>
</tr>
<tr>
<td>Wind/Other</td>
<td>201.6</td>
<td>453.6</td>
<td>705.6</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>4,788.0</strong></td>
<td><strong>6,451.2</strong></td>
<td><strong>7,408.8</strong></td>
</tr>
</tbody>
</table>

#### Average Annual Change

<table>
<thead>
<tr>
<th>Year</th>
<th>2010-2025</th>
<th>2025-2040</th>
<th>2010-2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>-2.1%</td>
<td>-0.9%</td>
<td>-1.5%</td>
</tr>
<tr>
<td>Gas</td>
<td>2.8%</td>
<td>1.4%</td>
<td>2.1%</td>
</tr>
<tr>
<td>Coal</td>
<td>1.1%</td>
<td>-0.5%</td>
<td>0.3%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>3.0%</td>
<td>2.3%</td>
<td>2.6%</td>
</tr>
<tr>
<td>Hydro</td>
<td>1.9%</td>
<td>1.2%</td>
<td>1.5%</td>
</tr>
<tr>
<td>Wind/Other</td>
<td>5.6%</td>
<td>3.0%</td>
<td>4.3%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>2.0%</strong></td>
<td><strong>0.9%</strong></td>
<td><strong>1.5%</strong></td>
</tr>
</tbody>
</table>

#### Distribution

<table>
<thead>
<tr>
<th>End Use</th>
<th>2010</th>
<th>2025</th>
<th>2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>6%</td>
<td>3%</td>
<td>2%</td>
</tr>
<tr>
<td>Gas</td>
<td>24%</td>
<td>27%</td>
<td>29%</td>
</tr>
<tr>
<td>Coal</td>
<td>45%</td>
<td>40%</td>
<td>32%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>14%</td>
<td>16%</td>
<td>20%</td>
</tr>
<tr>
<td>Hydro</td>
<td>6%</td>
<td>6%</td>
<td>6%</td>
</tr>
<tr>
<td>Wind/Other</td>
<td>4%</td>
<td>7%</td>
<td>10%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>100%</strong></td>
<td><strong>100%</strong></td>
<td><strong>100%</strong></td>
</tr>
</tbody>
</table>

**Total (net electricity)**

<table>
<thead>
<tr>
<th>Year</th>
<th>2010-2025</th>
<th>2025-2040</th>
<th>2010-2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>13,204.8</td>
<td>16,480.8</td>
<td>17,766.0</td>
</tr>
<tr>
<td>Gas</td>
<td>1,159.2</td>
<td>1,764.0</td>
<td>2,167.2</td>
</tr>
<tr>
<td>Coal</td>
<td>2,167.2</td>
<td>2,570.4</td>
<td>2,394.0</td>
</tr>
<tr>
<td>Nuclear</td>
<td>680.4</td>
<td>1,058.4</td>
<td>1,486.8</td>
</tr>
<tr>
<td>Hydro</td>
<td>302.4</td>
<td>403.2</td>
<td>478.8</td>
</tr>
<tr>
<td>Wind/Other</td>
<td>201.6</td>
<td>453.6</td>
<td>705.6</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>16,288.4</strong></td>
<td><strong>18,917.0</strong></td>
<td><strong>20,253.8</strong></td>
</tr>
</tbody>
</table>

#### Average Annual Change

<table>
<thead>
<tr>
<th>Year</th>
<th>2010-2025</th>
<th>2025-2040</th>
<th>2010-2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>1.5%</td>
<td>0.5%</td>
<td>1.0%</td>
</tr>
</tbody>
</table>

#### Distribution

<table>
<thead>
<tr>
<th>End Use</th>
<th>2010</th>
<th>2025</th>
<th>2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td><strong>100%</strong></td>
<td><strong>100%</strong></td>
<td><strong>100%</strong></td>
</tr>
</tbody>
</table>

**Source: ExxonMobil – Outlook for Energy, 2013; Jadwa investment**
## Attachment 3

### Breakdown of Global Oil & Gas Demand Forecast

<table>
<thead>
<tr>
<th>End Use</th>
<th>Oil Demand (in million toe)</th>
<th>Average Annual Change</th>
<th>Distribution</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2010</td>
<td>2025</td>
<td>2040</td>
</tr>
<tr>
<td>Residential/Commercial</td>
<td>378.0</td>
<td>403.2</td>
<td>403.2</td>
</tr>
<tr>
<td>Transportation</td>
<td>2,368.8</td>
<td>2,872.8</td>
<td>3,150.0</td>
</tr>
<tr>
<td>Industrial</td>
<td>1,486.8</td>
<td>1,764.0</td>
<td>1,890.0</td>
</tr>
<tr>
<td>Electricity</td>
<td>252.0</td>
<td>201.6</td>
<td>176.4</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>4,485.6</td>
<td>5,241.6</td>
<td>5,619.6</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>End Use</th>
<th>Gas Demand (in million toe)</th>
<th>Average Annual Change</th>
<th>Distribution</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2010</td>
<td>2025</td>
<td>2040</td>
</tr>
<tr>
<td>Residential/Commercial</td>
<td>630.0</td>
<td>781.2</td>
<td>831.6</td>
</tr>
<tr>
<td>Transportation</td>
<td>50.4</td>
<td>75.6</td>
<td>151.2</td>
</tr>
<tr>
<td>Industrial</td>
<td>1,083.6</td>
<td>1,436.4</td>
<td>1,663.2</td>
</tr>
<tr>
<td>Electricity</td>
<td>1,134.0</td>
<td>1,738.8</td>
<td>2,116.8</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>2,898.0</td>
<td>4,032.0</td>
<td>4,762.8</td>
</tr>
</tbody>
</table>

---

1: Net of electricity

**Source:** ExxonMobil – Outlook for Energy, 2013; Jadwa Investment
## Attachment 4

### Breakdown of Global Oil & Liquids Supply

#### Global Liquids Supply

<table>
<thead>
<tr>
<th></th>
<th>2011</th>
<th>2035</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>million bpd</td>
<td>%</td>
</tr>
<tr>
<td><strong>OPEC</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Crude Oil</td>
<td>29.3</td>
<td>35%</td>
</tr>
<tr>
<td>NGLs</td>
<td>5.7</td>
<td>7%</td>
</tr>
<tr>
<td>Unconventional</td>
<td>0.7</td>
<td>1%</td>
</tr>
<tr>
<td><strong>Total OPEC</strong></td>
<td><strong>35.7</strong></td>
<td><strong>42%</strong></td>
</tr>
<tr>
<td><strong>Non-OPEC</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Crude Oil</td>
<td>39.2</td>
<td>46%</td>
</tr>
<tr>
<td>NGLs</td>
<td>6.4</td>
<td>8%</td>
</tr>
<tr>
<td>Unconventional</td>
<td>3.2</td>
<td>4%</td>
</tr>
<tr>
<td><strong>Total Non-OPEC</strong></td>
<td><strong>48.8</strong></td>
<td><strong>58%</strong></td>
</tr>
<tr>
<td><strong>Global Liquids Production</strong></td>
<td><strong>84.5</strong></td>
<td><strong>100%</strong></td>
</tr>
</tbody>
</table>

#### Global Oil Supply

<table>
<thead>
<tr>
<th></th>
<th>2011</th>
<th>2035</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>million bpd</td>
<td>%</td>
</tr>
<tr>
<td><strong>OPEC</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>35.7</td>
<td>42%</td>
</tr>
<tr>
<td><strong>Non OPEC</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>48.8</td>
<td>58%</td>
</tr>
<tr>
<td><strong>Global Oil Production</strong></td>
<td><strong>84.5</strong></td>
<td><strong>100%</strong></td>
</tr>
</tbody>
</table>

*Source: IEA – World Energy Outlook, 2012; Jadwa Investment*
Attachment 5

Breakdown of Global Gas Supply

Gas Production by Regions
(in billion cubic feet per day)

<table>
<thead>
<tr>
<th>Regions</th>
<th>2010</th>
<th>2035</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>E. Europe/Eurasia</td>
<td>81.4</td>
<td>116.4</td>
</tr>
<tr>
<td>Middle East</td>
<td>45.6</td>
<td>78.2</td>
</tr>
<tr>
<td>Asia-Pacific</td>
<td>46.2</td>
<td>90.8</td>
</tr>
<tr>
<td>OECD Americas¹</td>
<td>78.9</td>
<td>103.3</td>
</tr>
<tr>
<td>Africa</td>
<td>20.2</td>
<td>41.4</td>
</tr>
<tr>
<td>Latin America</td>
<td>15.8</td>
<td>28.2</td>
</tr>
<tr>
<td>OECD Europe</td>
<td>29.4</td>
<td>20.8</td>
</tr>
<tr>
<td>Total</td>
<td>317.6</td>
<td>479.2</td>
</tr>
</tbody>
</table>

¹: Canada, Chile, Mexico and United States

<table>
<thead>
<tr>
<th>Growth (%)</th>
<th>Overall</th>
<th>Of which</th>
</tr>
</thead>
<tbody>
<tr>
<td>Percentage Growth</td>
<td>Overall</td>
<td>Annual Compound</td>
</tr>
</tbody>
</table>

Inter-Regional Trade of Gas
(in billion cubic feet per day)

<table>
<thead>
<tr>
<th>Type</th>
<th>2010</th>
<th>2035</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional</td>
<td>273.1</td>
<td>354.6</td>
</tr>
<tr>
<td>Unconventional</td>
<td>44.5</td>
<td>124.6</td>
</tr>
<tr>
<td>Total</td>
<td>317.6</td>
<td>479.2</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Growth (%)</th>
<th>Overall</th>
<th>Of which</th>
</tr>
</thead>
<tbody>
<tr>
<td>Percentage Growth</td>
<td>Overall</td>
<td>Annual Compound</td>
</tr>
</tbody>
</table>

Source: IEA – World Energy Outlook, 2012; Jadwa Investment
Attachment 6
A Brief on Shale Wells Technology & Productivity
Can the US Experience be Replicated?


They provide a good summary of the challenges (and of the opportunities when the micro-geology of the shales is well understood) which operators face in exploiting shale formations. They also explain why we view forecasting future oil or gas production from shale formations as quite uncertain, in particular for those basins still without any significant test wells.

QUOTE

The U.S. shale experience and international shale development

This [US EIA Report] treats non-U.S. shales as if they were homogeneous across the formation. If the U.S. experience in shale well productivity is replicated elsewhere in the world, then it would be expected that shale formations in other countries will demonstrate a great deal of heterogeneity, in which the geophysical characteristics vary greatly over short distances of a 1,000 feet or less. Shale heterogeneity over short distances is demonstrated in a recent article that shows that oil and natural gas production performance varies considerably across the fractured stages of a horizontal lateral and that a significant number of fractured stages do not produce either oil or natural gas; in some cases, up to 50 percent of the fractured stages are not productive. The authors of that article noted that:

“… a study including the production logs from 100 horizontal wells showed an enormous discrepancy in production between perforation clusters that is likely due to rock heterogeneity.”

One reason why 3,000-to-5,000-foot horizontal laterals are employed in the United States is to increase the likelihood that a portion of the horizontal lateral will be sufficiently productive to make the well profitable.

Because of shale rock heterogeneity over short distances, neighboring well productivity varies significantly, and well productivity across the formation varies even more. Shale formation productivity also varies by depth. For example, Upper Bakken Member shale wells are less productive than Lower Bakken Member shale wells.

Shale heterogeneity also means that some areas across the shale formation can have relatively high productivity wells (also known as sweet spots), while wells in other regions have lower productivities. However, because productivity also varies significantly for wells located in the same neighborhood, a single well test cannot establish a formation’s productivity or even the productivity within its immediate neighborhood.

1 Society of Petroleum Engineers, Journal of Petroleum Technology, Utpal Ganguly and Craig Cipolla (Schlumberger), "Multidomain Data and Modeling Unlock Unconventional Reservoir Challenges," August 2012, pages 32-37; see Figure 2 for the variation in productivity along the fractured stages of four wells.
This complicates the exploration phase of a shale's development because a company has to weigh the cost of drilling a sufficient number of wells to determine the local variation in well productivity against the risk that after drilling enough wells, the formation under the company’s lease still proves to be unprofitable. For those foreign shales that are expected to have both natural gas-prone and oil-prone portions, formation heterogeneity means that there could be an extended transition zone across a shale formation from being all or mostly natural gas to being mostly oil. The best example of this gradual and extended transition from natural gas to oil is found in the Eagle Ford Shale in Texas, where the distance between the natural gas-only and mostly-oil portions of the formation are separated by 20 to 30 miles, depending on the location. This transition zone is important for two reasons.

First, a well's production mix of oil, natural gas, and natural gas liquids can have a substantial impact on that well’s profitability both because of the different prices associated with each component and because liquids have multiple transportation options (truck, rail, barge, pipeline), whereas large volumes of natural gas are only economic to transport by pipeline. Because many countries have large natural gas deposits that well exceed the indigenous market’s ability to consume that natural gas (e.g., Qatar), the shale gas is of no value to the producer and is effectively stranded until a lengthy pipeline or LNG export terminal has been built to transport the natural gas to a country with a larger established consumption market.

Second, the production of shale oil requires that at least 15 percent to 25 percent of the pore fluids be in the form of natural gas so that there is sufficient gas-expansion to drive the oil to the wellbore. In the absence of natural gas to provide reservoir drive, shale oil production is problematic and potentially uneconomic at a low production rate. Consequently, producer drilling activity that currently targets oil production in the Eagle Ford shale is primarily focused on the condensate-rich portion of the formation rather than those portions that have a much greater proportion of oil and commensurately less natural gas.

Shale formation heterogeneity also somewhat confounds the process of testing alternative well completion approaches to determine which approach maximizes profits. Because of the potential variation in neighboring well productivity, it is not always clear whether a change in the completion design is responsible for the change in well productivity. Even a large well sample size might not resolve the issue conclusively as drilling activity moves through inherently higher and lower productivity areas.

Shale formation heterogeneity also bears on the issue of determining a formation’s ultimate resource potential. Because companies attempt to identify and produce from the high productivity areas first, the tendency is for producers to concentrate their efforts in those portions of the formation that appear to be highly productive, to the exclusion of much of the rest of the formation. For example, only about 1 percent of the Marcellus Shale has been production tested. Therefore, large portions of a shale formation could remain untested for several decades or more, over which time the formation’s resource potential could remain uncertain.

UNQUOTE

2 Of course, there will be instances where the geophysical properties of a single well rock sample are so poor (e.g. high clay content, low porosity, low carbon content) or a well production test is so discouraging that the company abandons any further attempts in that portion of the formation.
Attachment 7

Estimate of Technically Recoverable Oil Resources (as of end-2011)

(in billion barrels)

<table>
<thead>
<tr>
<th></th>
<th>Conventional Oil</th>
<th>NGLs</th>
<th>Sub-Total</th>
<th>Extra Heavy Oil &amp; Bitumen</th>
<th>Tight Oil</th>
<th>Sub-Total</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>OECD Americas</td>
<td>253</td>
<td>57</td>
<td>310</td>
<td>809</td>
<td>70</td>
<td>879</td>
<td>1,189</td>
</tr>
<tr>
<td>Europe</td>
<td>59</td>
<td>31</td>
<td>90</td>
<td>3</td>
<td>18</td>
<td>21</td>
<td>111</td>
</tr>
<tr>
<td>Asia &amp; Oceania</td>
<td>5</td>
<td>11</td>
<td>16</td>
<td>0</td>
<td>13</td>
<td>13</td>
<td>29</td>
</tr>
<tr>
<td>Sub-Total</td>
<td>317</td>
<td>99</td>
<td>416</td>
<td>812</td>
<td>101</td>
<td>913</td>
<td>1,329</td>
</tr>
<tr>
<td>Non-OECD E. Europe / Eurasia</td>
<td>352</td>
<td>81</td>
<td>433</td>
<td>552</td>
<td>14</td>
<td>566</td>
<td>999</td>
</tr>
<tr>
<td>Asia</td>
<td>95</td>
<td>26</td>
<td>121</td>
<td>3</td>
<td>50</td>
<td>53</td>
<td>174</td>
</tr>
<tr>
<td>Middle East</td>
<td>982</td>
<td>142</td>
<td>1,124</td>
<td>14</td>
<td>4</td>
<td>18</td>
<td>1,142</td>
</tr>
<tr>
<td>Africa</td>
<td>255</td>
<td>52</td>
<td>307</td>
<td>2</td>
<td>33</td>
<td>35</td>
<td>342</td>
</tr>
<tr>
<td>Latin America</td>
<td>245</td>
<td>32</td>
<td>277</td>
<td>498</td>
<td>37</td>
<td>535</td>
<td>812</td>
</tr>
<tr>
<td>Sub-Total</td>
<td>1,929</td>
<td>333</td>
<td>2,262</td>
<td>1,069</td>
<td>138</td>
<td>1,207</td>
<td>3,469</td>
</tr>
<tr>
<td>Total</td>
<td>2,246</td>
<td>432</td>
<td>2,678</td>
<td>1,881</td>
<td>239</td>
<td>2,120</td>
<td>4,798</td>
</tr>
</tbody>
</table>

Percentage

<table>
<thead>
<tr>
<th></th>
<th>Conventional</th>
<th>Extra Heavy Oil &amp; Bitumen</th>
<th>Tight Oil</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>OECD Americas</td>
<td>47%</td>
<td>9%</td>
<td>56%</td>
<td>100%</td>
</tr>
<tr>
<td>Europe</td>
<td>43%</td>
<td>29%</td>
<td>41%</td>
<td>25%</td>
</tr>
<tr>
<td>Asia &amp; Oceania</td>
<td>39%</td>
<td>5%</td>
<td>44%</td>
<td>100%</td>
</tr>
<tr>
<td>Total</td>
<td>14%</td>
<td>23%</td>
<td>16%</td>
<td>28%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Conventional</th>
<th>Extra Heavy Oil &amp; Bitumen</th>
<th>Tight Oil</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>OECD E. Europe / Eurasia</td>
<td>16%</td>
<td>19%</td>
<td>16%</td>
<td>21%</td>
</tr>
<tr>
<td>Asia</td>
<td>4%</td>
<td>6%</td>
<td>5%</td>
<td>4%</td>
</tr>
<tr>
<td>Middle East</td>
<td>44%</td>
<td>33%</td>
<td>42%</td>
<td>24%</td>
</tr>
<tr>
<td>Africa</td>
<td>11%</td>
<td>12%</td>
<td>11%</td>
<td>7%</td>
</tr>
<tr>
<td>Latin America</td>
<td>11%</td>
<td>7%</td>
<td>10%</td>
<td>17%</td>
</tr>
<tr>
<td>Total</td>
<td>86%</td>
<td>77%</td>
<td>84%</td>
<td>72%</td>
</tr>
<tr>
<td>Total</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
</tr>
</tbody>
</table>

Source: IEA - World Energy Outlook 2012, Jadwa Investment

Note: The IEA includes deep-water oil production under conventional sources. As other analysts, we have elected to include and comment on it under unconventional sources, because of the technical challenges which its development poses.

Note further that, even without deep-water resources:

(i) unconventional resources represent as high as 44% of the remaining technically recoverable liquids resources;

(ii) oil sands and extra-heavy oil represent a large portion (39%) of all remaining technically recoverable liquids resources; and,

(iii) tight oil represents only 5% of such resources.

As discussed in Sections VII, VIII and XI, oil sands and extra-heavy oil are particularly expensive to extract. Tight oil will thus be the unconventional source of oil of choice, in particular in the US, where above ground factors favor its development.
Attachment 8

Sources

Section I

- Most this Section is extracted from the “Squeezing more oil from the ground” article which L. Maugeri published in October 2009 in Scientific American.

Section II

- The discussion on, and definition of, resources and reserves in the oil & gas industry takes from the IEA “World Economic Outlook 2012” report.
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