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Oil

Contents

Strategic insight

1. Introduction

Oil plays an important role in the global energy balance, accounted for 32% of energy consumption in 2010. This proportion has changed very little in the last 20 years (the figure was 37% in 1990), despite the fact that the total amount of energy consumed worldwide has increased by more than 50% over the same period. This trend has been driven primarily in the last decade by emerging countries.

At regular points throughout these two decades, questions have been raised about the growing scarcity of fossil fuel resources and the imminent inevitability of peak oil.

So what is the status of oil reserves in 2013? What have been the major trends of the past two decades? What can we expect to happen in the near future?

The trend in oil reserves between 1991 and 2011

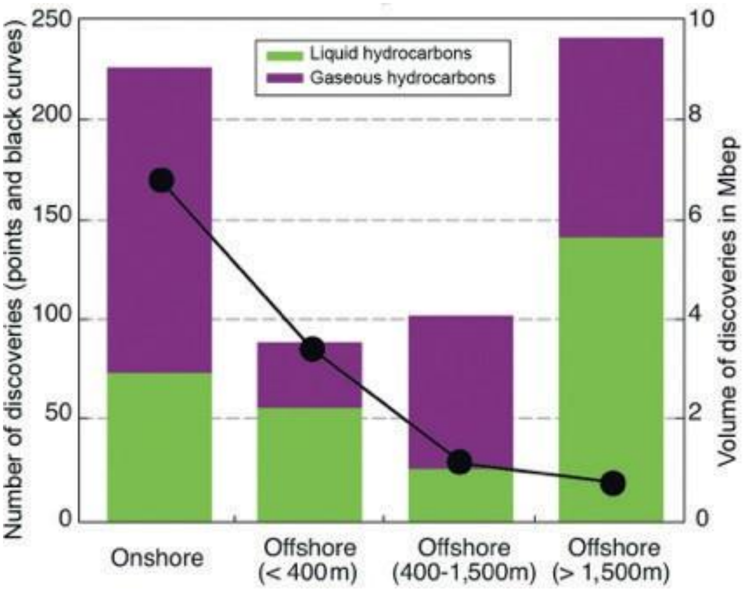
Different sources regularly quoted as benchmarks estimate current global oil reserves at 1,650 billion barrels or Gb (BP Statistical Review). Despite high levels of consumption that have been growing by 32 % since 1991 - from 66 Mbd (million barrels per day) in 1991 to 88 Mbd in 2011 - reserves have increased by 60% over the same period, representing a gain of 620 Gb. Given cumulative consumption of the same order (595 Gb), this means that new discoveries and reappraisals have totaled 1,210 Gb since 1991, which is a large amount by any measure. This explains why the reserves-to-production ratio has increased from 43 to 54 years.

Every region of the world outside Europe saw its oil reserves increase between 1991 and 2011. Those of South America (19.7% of the total), Africa (8%) and the CIS (7.7%) rose most significantly, the first having quadrupled (as a result of the decision of Venezuela to report its huge extra heavy oil resources), whilst the other two doubled over the period. The trend for other regions varied from +77% for North America (13.2% of total as a result of the Canada effect) to 20% for the Middle East (48.1%) and 12% for Asia (2.5%). Europe (0.9%) was the only region to see a decline of 21%.

The increasing importance of South America, whose contribution to total reserves has risen from 7% to nearly 20%, has reduced the influence of the Middle East on the global oil stage. It is true that this region still contains nearly half of the world's oil reserves, but this represents a significant reduction from the 1990s, when the figure was 64%.

On the other hand, one parameter of particular market sensitivity that has changed very little is the dominant role played by OPEC, which still accounts for more than 70% of the world's total reserves, since its members include the two 'heavyweights' of Venezuela (17.9%) and Saudi Arabia (16.1%). Four other Middle Eastern states - Iran, Iraq, Kuwait and the United Arab Emirates - together hold 30% of global oil reserves.

Figure 1
Breakdown of 2011 discoveries by type of deposit
Source: Wood Mackenzie.



2. Technical and economic considerations

The growth in the deep- and ultra-deep offshore

Over the past two decades, ongoing improvements in seismic prospecting systems, geological knowledge, sedimentary basin modeling (reconstituting the geological and oil history of a basin) and production technologies have all broadened the scope of oil exploration. Our knowledge of subsea basins and the continual progress made over the last 50 years in marine exploration and production techniques have led to discoveries at increasing depths and contributed to the emergence of new oil and gas powers.

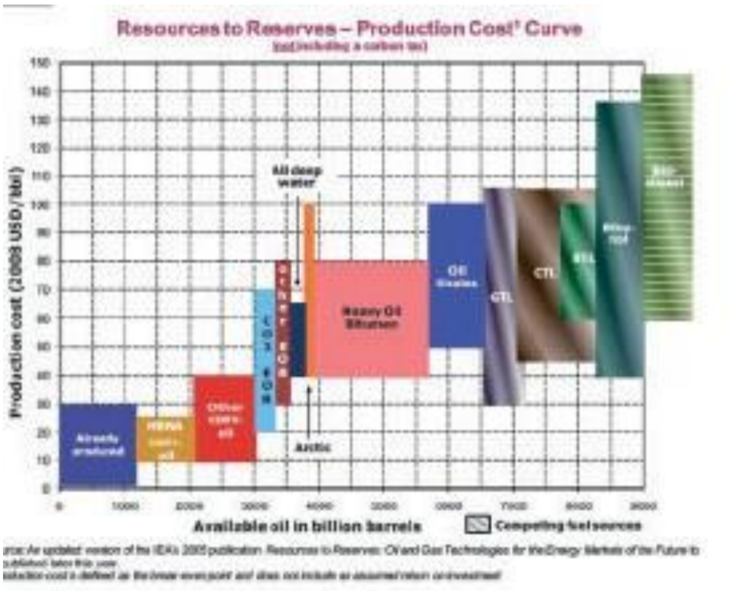
In West Africa, the figures for oil reserves in Nigeria and Angola have risen by 17 Gb and 12 Gb respectively since the start of the 1990s. In Brazil, discoveries in increasingly deep and complex subsea areas have been important the last few years : particular highlights being the Tupi field discovered in 2006 beneath more than 2,000 meters of water and 5,000 meters of sediments, and more recently, the Carioca field. Both deposits contain reserves of several billion barrels of oil equivalent.

In the most recent past, the contribution from the deep- and ultra-deep offshore have become even more important. The 22 discoveries made in 2011 at water depths in excess of 1,500 meters account for two-thirds by volume of all hydrocarbon discoveries for the year (Figure 1).

The increasingly important contribution made by 'non-conventional' hydrocarbons.

Although there is no strict definition covering all non-conventional oils and gases, this term is generally considered today to cover all those hydrocarbons that are difficult to extract, either

Figure 2



because they are found in very low permeability horizons, or because their nature makes them difficult to produce. In terms of liquids, this means heavy and extra-heavy oils, tar sands, shale oils and tar shales; for natural gas, it means tight gas from compact reservoirs, coalbed methane gas, shale gas and in the long term methane hydrates.

Over the last twenty years, the growth in non-conventional oils has accounted for a large proportion of the renewal and increase seen in global reserves.

The exploitation of Canadian tar sands (169 Gb of reserves) and heavy and extra-heavy crudes in Venezuela (220 Gb) have contributed very significantly to available reserves in these two countries increasing by a factor of four since the start of the 1990s. At 296 Gb, Venezuela now leads the world in terms of oil reserves, ahead of Saudi Arabia (265 Gb). The volumes available in Canada (total reserves of 175 Gb) outstrip those of both Iraq (143 Gb) and Iran (151 Gb).

More recently, the development of light tight oils in the USA marks another step change. The growth in source rock oils and the liquid hydrocarbons associated with shale gas are changing the status quo for liquid hydrocarbons by reversing the downward trend that began in the mid-1980s: having fallen from 11 Mbd in 1985 to around 7 Mbd in 2005, volumes have now recovered to approximately 9 Mbd.

The major impact of non-conventionals on the oil price

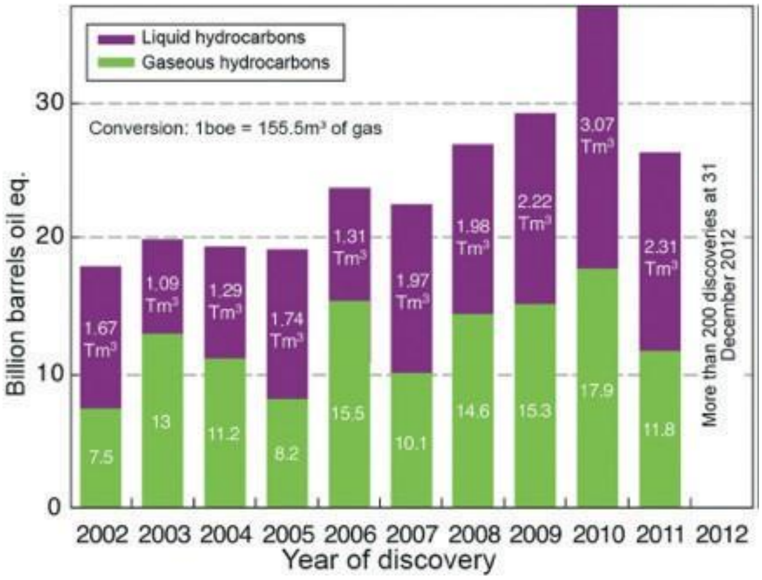
The increase in production levels of heavy oils from Canada (and to a lesser extent, Venezuela) over the last decade have had a significant effect on trends in the oil price since 2005. In the 1990s, they accounted for only 1% of total supply (0.4 Mbd). They now contribute 7% of the total (3.6 Mbd), half of which are Canadian heavy oils. As shown on the Figure 2 (above), the cost of these non-conventional oils is higher than conventional ones.

The oil price has adjusted rather aggressively to this new reality. In 2011 constant dollar terms, the price of Brent crude rose from an annual average of USD24 per barrel to USD40 per barrel between 1986 (year of the oil price collapse) and 2003. Rising demand from emerging coun-

Figure 3

Estimated new discoveries between 2002 and 2012

Source: Wood Mackenzie.



tries was then a major factor in imposing the necessity for a new price balance in order to develop the non-conventional oils crucial to balance supply with demand. As a result, the oil price rose from USD45 per barrel in 2004 to USD72 per barrel in 2006, reaching USD101 per barrel in 2008. Excluding the effect of the global economic crisis, which brought the price back down to USD64 barrel in 2009, Brent crude is now trading at over USD100 per barrel.

It is true that this USD100+ price per barrel includes a ‘geopolitical’ component (resulting from the situation in North Africa and the Middle East since 2010), but it also reflects the higher production costs involved in exploiting non-conventional oils, including heavy oils. These costs mean that the minimum tenable price is now estimated at between USD80 and USD90 per barrel.

Over the long term, and contrary to the traditional perception of inexorable price rises, the concept of a new balance at below the USD100 level is now being suggested. The background to this suggestion is the increasing importance of shale oils, whose production cost is estimated at approximately USD50 per barrel in the USA. This scenario is envisageable only on two conditions: a reduction in political tension in sensitive oil-producing regions, and reconsideration of the development of heavy oils in Canada, which are currently setting the minimum benchmark price for the market. Management of the demand side, and specifically the demand from the transport industries, could also see this currently uncertain scenario become a reality at some point in the future.

The increase in prices and investment over the last 10 years

Since the start of the 21st century, rising prices for crude (from USD28 per barrel in 2000 to USD111 per barrel in 2011 for Brent crude) and natural gas has enabled the development of resources previously rated as uneconomic, as well as non-conventional, complex and technical hydrocarbons. With the price of Brent crude remaining sustainably above USD100 per barrel, the exploitation of expensive resources with development costs in the range of USD50 to USD80 per barrel becomes a possibility.

The rise in oil and natural gas prices has also been matched by increased investment in exploration, which totaled nearly USD80 billion in 2012; four times the level of ten years earlier.

This acceleration in exploration activity has contributed to the emergence of new oil and gas producing regions in the Mediterranean (the Levantine Basin) and East Africa (the Rovuma Basin).

Discoveries of conventional oil in the period 2006-2011 averaged 14 Gb per year; a figure equivalent to 40% of consumption over the same period. These volumes are supplemented by the annual revaluations of older discoveries and the development of non-conventional oils. Overall, global oil reserves have increased at a rate close to 4% per annum.

New discoveries of natural gas represented 65% of global consumption over the same period (Figure 3).

3. Market trends and outlook

What is the risk of a future peak?

In the medium term, the relatively high price levels (with the exception of gas prices in the USA) that are enabling the development of costly resources and sustained levels of exploration and production seen in recent years, are likely to ensure that the current trend of bringing new reserves on stream continues.

In the longer term, there is the issue of production leveling out. In terms of liquid hydrocarbons, the IEA published detailed data at the end of 2012 on technically recoverable oil resources (in its WEO 2012). These data identify a potential of 5,870 Gb, which includes 2,200 Gb of conventional oils, 430 Gb of natural gas liquids, 1,880 Gb of heavy and extra-heavy oils and 240 Gb of shale oils. The same IEA report suggest that oil consumption will trend upwards from the *New Policies* benchmark scenario of 32 Gb per year (88 Mbd) in 2011 to 34 Gb (93 Mbd) in 2035. The overall total would therefore be approximately 820 Gb, or 14% of exploitable potential. Assuming stability of consumption beyond 2035 (which remains to be seen), it would take 60 years to consume half of the potential. On the basis of these figures, the risk of reaching a peak in the short term is not very likely.

On the other hand, the conventional oils that account for 25 Gb of production annually will come under increasing - and even very substantial - pressure over the next 10 to 20 years. This will probably be the central challenge for the oil market if demand remains sustained over the next two decades. The practical issue will therefore be one of compensating for this gradual decline by exploiting non-conventional heavy oils and shale oils: this is creating a significant technological and environmental challenge.

Despite unbroken growth in consumption, reserves of hydrocarbons have continued to increase over the last 20 years.

In the short term, the risks of market tension do not lie in those volumes known to be technically and economically accessible, but rather in the unequal distribution of reserves around the world. Today's development of technical and non-conventional hydrocarbons is changing the status quo, as can already be seen in the USA, which is reducing its dependency by developing source rock hydrocarbons.

In the longer term, the slowdown in oil consumption that is already substantial in OECD countries that have introduced energy efficiency measures with particular focus on the transport industries, could lead to a plateau in demand: ‘Peak demand’ rather than ‘Peak oil’.

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Global tables

Table 1
Oil: Proven Recoverable Reserves at end 2011

Country	million tonnes	million barrels
Saudi Arabia	36201	265400
Venezuela	28780	211000
Iran	20624	151200
Iraq	15686	115000
Kuwait	13845	101500
United Arab Emirates	13340	97800
Russian Federation	8184	60000
Libya	6424	47100
Nigeria	5074	37200
United States of America	4215	30900
Kazakhstan	4092	30000
Qatar	3465	25400
Algeria	3170	23241
Brazil	2053	15054
Mexico	1367	10025
Angola	1296	9500
Ecuador	982	7200
Azerbaijan	955	7000
India	777	5700
Oman	750	5500
Norway	726	5320
Sudan	682	5000
Canada	678	4972
Egypt	600	4400
Vietnam	600	4400
Malaysia	546	4000
Indonesia	532	3900
Gabon	505	3700
Australia	450	3300
Yemen	409	3000
United Kingdom	382	2800
Argentina	355	2600
Syria	335	2459
Guinea	232	1700
Congo (Republic of)	218	1600
Chad	205	1500
Brunei Darussalam	150	1100
Equitorial Guinea	150	1100
Denmark	111	811
Turkmenistan	82	600
Uzbekistan	81	594
Peru	79	582

Italy	76	559
Thailand	62	453
Tunisia	55	400
Romania	54	396
Trinidad and Tobago	46	335
Ghana	2	15
China		20400
Colombia		1900
Global Total	**179 682**	**1 339 617**

Table 2
Oil: Production Figures at end 2011

Country	thousand tonnes	thousand barrels
Albania	800	5 864
Algeria	90 700	664 831
Angola	85 000	623 050
Argentina	30 300	222 099
Australia	21 000	153 930
Austria	840	6 157
Azerbaijan	45 800	335 714
Bahrain	10 000	73 300
Bangladesh	300	2 199
Barbados	50	367
Belarus	1 700	12 461
Bolivia	2 300	16 859
Brazil	105 100	770 385
Brunei Darussalam	8 100	59 373
Bulgaria	22	161
Cameroon	3 100	22 723
Canada	63 093	462 472
Chad	6 000	43 980
Chile	200	1 466
China	203 600	1 492 388
Colombia	334	2 449
Congo (DRC)	1 100	8 063
Congo (Republic of)	15 200	111 416
Cote d'Ivoire	1 600	11 728
Croatia	664	4 870
Cuba	3 400	24 922
Czech Republic	165	1 209
Denmark	2 700	19 791
Ecuador	27 100	198 643
Egypt	35 100	257 283
Estonia	600	4 398
Equitorial Guinea	12 500	91 625
Finland	500	3 665
France	900	6 597
Gabon	12 500	91 625
Georgia	100	733
Germany	2 677	19 623
Ghana	3 600	26 388

Greece	100	733
Guatemala	600	4 398
Hungary	700	5 131
India	38 200	280 006
Indonesia	35 327	258 947
Iran	205 800	1 508 514
Iraq	134 200	983 686
Israel	50	367
Italy	5 280	38 702
Japan	707	5 182
Kazakhstan	80 060	586 840
Korea (Republic)	1 000	7 330
Kuwait	134 300	984 419
Kyrgyzstan	100	733
Libya	21 400	156 862
Lithuania	100	733
Malaysia	31 300	229 429
Mauritania	1 300	9 529
Mexico	126 958	930 604
Mongolia	300	2 199
Morocco	50	367
Myanmar (Burma)	900	6 597
Netherlands	1 100	8 063
New Zealand	2 300	16 859
Nigeria	120 200	881 066
Norway	92 200	675 826
Oman	42 100	308 593
Pakistan	3 500	25 655
Papa New Guinea	1 000	7 330
Peru	6 600	48 378
Philippines	800	5 864
Poland	602	4 413
Qatar	64 400	472 052
Romania	4 500	32 985
Russian Federation	509 000	3 730 970
Saudi Arabia	525 800	3 854 114
Serbia	1 032	7 565
Slovakia	500	3 665
South Africa	700	5 131
Spain	100	733
Sudan	22 300	163 459
Syria	16 700	122 411
Taiwan	50	367
Tajikistan	50	367
Thailand	10 400	76 232
Trinidad and Tobago	5 900	43 247
Tunisia	3 700	27 121
Turkey	2 400	17 592
Turkmenistan	10 400	76 232
Ukraine	3 300	24 189
United Arab Emirates	138 400	1 014 472
United Kingdom	52 000	381 160
United States of America	352 300	2 582 359

Uzbekistan	4 100	30 053
Venezuela	154 800	1 134 684
Vietnam	15 900	116 547
Yemen	10 300	75 499
Global total	**3 796 912**	**27 831 366**

Country notes

The following Country Notes on Crude Oil and Natural Gas Liquids provide a brief account of countries with significant oil reserves/production. They have been compiled by the Editors, drawing upon a wide variety of material, including information received from WEC Member Committees, national and international publications.

Algeria

Proved recoverable reserves (crude oil and NGLs, million barrels)	23 241
2011 production (crude oil and NGLs, thousand b/d)	665
R/P ratio (years)	35.0
Year of first commercial production	1950

Algeria's indigenous oil reserves are the third largest in the African region, after Libya and Nigeria. The principal oil provinces are located in the central and southeastern parts of the country, with the largest oil field Hassi Messaoud, discovered in 1956. Substantial volumes of NGLs (condensate and LPG) are produced at Hassi R'mel and other gas fields. Algerian crudes are of high quality, with a low sulphur content.

12 511 million cubic metres (78.7 billion barrels) of oil in place and 3 695 million cubic metres (23.2 billion barrels) of proved recoverable oil reserves. Published sources generally quote Algeria's reserves as around 12.2 billion barrels, which would appear to exclude NGLs. The bulk of its crude oil exports are consigned to Western Europe and North America.

Angola

Proved recoverable reserves (crude oil and NGLs, million barrels)	9 500
2011 production (crude oil and NGLs, thousand b/d)	623
R/P ratio (years)	15
Year of first commercial production	1956

According to *Oil & Gas Journal* estimates for the end of 2011, Angola had proved reserves of 9.5 billion barrels of crude oil. That figure is the second-largest in Sub-Saharan Africa behind Nigeria, and ranks 18th in the world. Angola's crude oil is light and sweet, making it ideal for export to major world markets like China and the United States. Exploration and production in offshore Angola is advancing at a rapid pace, and foreign investors are beginning to consider some onshore opportunities economically viable. Exports continue to drive Angolan oil production, but the development of new refining capacity could help ease domestic demand shortages that have plagued the country since the end of the civil war in 2002. Prospects for growth in the oil sector are good, but instability and the threat of conflict continue to temper expectations.

Angola's rise as a major oil-producing nation came relatively recently due to the country's long civil war (1975-2002), which restricted exploration in the country. Once Angola began to stabilize its oil production increased dramatically, more than doubling from 896,000 barrels per day (bbl/d) in 2002 to 1.84 million bbl/d of total liquids in 2011. Angola briefly challenged Nigeria as the top oil producer in Sub-Saharan Africa in 2009, but Angola's total liquid production declined slightly in 2010 and again in 2011. Crude oil production in Angola slipped to 1.79 million bbl/d in 2011, but the additions from new projects like the Kizomba Satellites should help Angola reverse that trend. These declines came as a result of regular maintenance and normal decline in the country's older fields, and Angola's government is targeting a return to the 2 million bbl/d production-levels it achieved in 2008 by 2014.

Argentina

Proved recoverable reserves (crude oil and NGLs, million barrels)	2 600
2011 production (crude oil and NGLs, thousand b/d)	222
R/P ratio (years)	11
Year of first commercial production	1907

Argentina is largely self-sufficient in crude oil, but imports oil products. Relatively low levels of exploration activity, combined with natural declines from maturing fields, explain the gradual erosion of oil production from its peak in 1998.Labor unrest has periodically shut-in Argentina's oil production, with concomitant impacts on exports, refinery runs, and local product supply. Separate disruptions affecting up to 100,000 barrels of output per day (bbl/d) plagued the sector in late 2010 and early 2011. The most recent disruption occurred in the Cerro Dragón oil field, which produces about 95,000 bbl/d, or roughly 15 percent of Argentina's total output. Production was significantly curbed at the field in late June when workers went on strike and blocked road access to the field. Negotiations between the field's operator, Pan American Energy (PAE), and labor representatives have reduced tensions and output at the field began to slowly ramp up in July 2012.

Australia

Proved recoverable reserves (crude oil and NGLs, million barrels)	3 300
2011 production (crude oil and NGLs, thousand b/d)	153
R/P ratio (years)	20
Year of first commercial production	1964

Although drilling for oil took place as long ago as 1892, it was not until well after World War II that Australia achieved oil-producer status. Since then, numerous oil fields have been discovered, notably in the following areas: Gippsland Basin (Bass Strait), off Victoria; Cooper Basin, South Australia; Eromanga and Surat Basins, Queensland; Carnarvon Basin (North West Shelf) off Western Australia; Bonaparte Basin in the Timor Sea.

The latest data on oil reserves published by Geoscience Australia as a component of its report on the *Oil and Gas Resources of Australia* 2008 (OGRA) relates to the situation as at 1 January 2009. At this point in time there were (in terms of millions of barrels) 881.6 of crude oil, 704.5 of condensate and 749.0 of naturally-occurring LPG in Category 1 (comprising 'current reserves of those fields which have been declared commercial. It includes both proved and probable reserves'). The total crude oil-plus-NGLs figure of 2 335 million barrels compares with the 1 January 2005 total of 2 085 million barrels quoted in OGRA 2004 for this category (which was entitled 'remaining commercial reserves' in another OGRA 2004 table).

Geoscience Australia also provides an alternative assessment, using the McKelvey classification, resulting in 'Economic Demonstrated Resources' (in millions of barrels) of 1 181 crude oil, 2 137 condensate and 1 095 LPG, giving a grand total of 4 413.

According to The *Oil and Gas Journal* (OGJ), Australia had 3.3 billion barrels of proven oil reserves as of January 1, 2011. Australian crude oil is of the light variety, typically low in sulfur and wax, and therefore of higher value than the heavier crudes. The majority of reserves are located off the coasts of Western Australia, Victoria, and the Northern Territory. Western Australia has 64 percent of the country's proven crude oil reserves, as well as 75 percent of its condensate and 58 percent of its LPG. The two largest producing basins are the Carnarvon Basin in the northwest and the Gippsland Basin in the southeast. While Carnarvon Basin production, accounting for 72 percent of total liquids production, is mostly exported, Gippsland Basin production, accounting for 24 percent, is predominantly used in domestic refining.

Azerbaijan

Proved recoverable reserves (crude oil and NGLs, million barrels)	7 000
2011 production (crude oil and NGLs, thousand b/d)	335
R/P ratio (years)	20.9
Year of first commercial production	1873

This is one of the world's oldest oil-producing areas, large-scale commercial production having started in the 1870s. During World War II the republic was the USSR's major source of crude, but then decreased in importance as the emphasis moved to Siberia. The development of Azerbaijan's offshore oil resources in the Caspian Sea, currently under way, has re-established the republic as a major oil producer and exporter. With new Caspian fields coming into production, oil output has risen year by year since 1998. The bulk of Azerbaijan's production is obtained offshore.

Azerbaijan's proven crude oil reserves are estimated at 7 billion barrels in January 2012, according to the *Oil and Gas Journal* (OGJ). The country's largest hydrocarbon basins are located offshore in the Caspian Sea, particularly the Azeri Chirag Guneshli (ACG) field, which accounted for nearly 80 percent of Azerbaijan's total oil output in 2010.

Oil production in Azerbaijan increased from 288,000 barrels per day (bbl/d) in 2000 to 1.1 million bbl/d in 2010. Monthly data through December 2011 show that this year's production thus far has decreased slightly.

Azerbaijan exported an estimated 777,000 bbl/d in 2010, falling by about 8 percent compared with 2009. Although Azerbaijan has three export pipelines, most (about 80 percent) of its oil is exported via the BTC. In addition, small amounts are shipped by truck and railway.

Brazil

Proved recoverable reserves (crude oil and NGLs, million barrels)	15 054
2011 production (crude oil and NGLs, thousand b/d)	770
R/P ratio (years)	19.6
Year of first commercial production	1940

The estimates of Brazil's proved oil reserves reported for previous editions of the SER have been based on the 'measured/indicated/inventoried reserves' published by the Ministério de Minas e Energia in its *Balanço Energético Nacional* (BEN), which broadly equate to 'proved+probable' reserves. For the present *Survey*, the WEC Member Committee for Brazil has been able to supply as a separate item the 'proved' component (8 053) of the BEN 2009 figure of 12 801 million barrels. The remaining amount of 4 748 million barrels is allocated to ‘probable’ reserves, while the BEN’s ‘inferred/estimated’ category is classified as ‘possible’. Of the proved reserves reported by the Member Committee, 93% is located offshore.

The standard published assessments of proved reserves continue to reflect recent generations of the BEN equivalent of ‘proved+probable’ reserves.

Oil production has followed a strongly upward trend for more than 10 years, reaching an average of 1.9 million b/d in 2008. Much interest is currently being shown in Brazil’s offshore (especially deep-water) oil fields and in particular the massive reserves discovered in the pre-salt formation, with production from the Tupi field expected to begin around the end of 2010.

According to the *Oil and Gas Journal* (OGJ), Brazil has 14.0 billion barrels of proven oil reserves in 2012, the second-largest in South America after Venezuela. The offshore Campos and Santos Basins, located off the country’s southeast coast, hold the vast majority of Brazil’s proven reserves. In 2010, Brazil produced 2.7 million barrels per day (bbl/d) of liquids, of which 75 percent was crude oil. Average liquids production in Brazil contracted slightly in 2011, with modest gains in crude oil production offset by a decrease in ethanol production stemming from a poor sugar cane harvest.

Most Brazilian oil is currently produced in the southeastern region of the country in Rio de Janeiro and Espírito Santo states. More than 90 percent of Brazil’s oil production is offshore in very deep water and consists of mostly heavy grades. Six fields in the Campos Basin (Marlim, Marlim Sul, Marlim Leste, Roncador, Jubarte, and Barracuda) account for more than half of Brazil’s crude oil production. These Petrobras-operated fields each produce between 100,000 and 350,000 bbl/d.

Brunei

Proved recoverable reserves (crude oil and NGLs, million barrels)	1 100
2011 production (crude oil and NGLs, thousand b/d)	59
R/P ratio (years)	18.7
Year of first commercial production	1929

Brunei is a substantial producer and exporter of crude oil and natural gas for Asia and relies on hydrocarbon revenues for nearly two-thirds of its gross domestic product. Through its long-standing joint venture with Shell, Brunei has produced oil for several decades, primarily from two large, mature fields—Southwest Ampa and Champion—in the offshore Baram Delta. After reaching a recent peak of 220,000 barrels per day (bbl/d) in 2006, Brunei’s oil production has declined to 141,000 bbl/d in 2012.

Despite the recent decline in production, Brunei is the largest net exporter of total oil liquids in the Asia-Pacific region given the country’s minimal domestic consumption. In 2012, Brunei’s net oil exports were around 125,000 bbl/d, mostly in the form of crude oil sent to key Asian oil consumers. Brunei plans to expand its refinery capacity, as Chinese company Zhejiang Hengyi Group is constructing a new refinery with a capacity of 135,000 bbl/d that is scheduled to come online by 2015. This new facility could shift the dynamics of the country’s crude exports in favor of consuming more crude and exporting more petroleum products.

Canada

Proved recoverable reserves (crude oil, NGLs, synthetic crude and natural bitumen, million barrels)	4 972
2011 production (crude oil, NGLs, synthetic crude and natural bitumen), thousand b/d)	562
R/P ratio (years)	10.0
Year of first commercial production	1862

The levels of proved recoverable reserves adopted for the present *Survey* correspond with the 'Remaining Reserves as at 2008-12-31' given in the *2008 Report of the Reserves Committee of the Canadian Association of Petroleum Producers* (CAPP) in the CAPP *Statistical Handbook* (as at February 2010). Reserves comprise 765 million m3 of conventional crude oil, 200 million m3 of natural gas liquids (66 pentanes plus and 134 ethane/propane/butane), and 2 508 million m3 of oil sands and natural bitumen (1 451 'developed mining - upgraded and bitumen' and 1 057 'developed in situ - bitumen').

Two provinces (Alberta and Saskatchewan) account for the bulk of western Canada's conventional crude oil reserves. The East Coast Offshore reserves hold 233 million m3 of crude oil. Most of the NGL reserves are located in Alberta.

There is no consensus as regards the treatment of Canadian oil sands/bitumen in compilations of proved oil reserves. Some published compilations (e.g. OPEC, OAPEC, BGR) continue to exclude it entirely, whilst at the other extreme, *Oil & Gas Journal* includes the whole of the ERCB's 'established oil sands reserves'(see above).

The approach adopted for the present *Survey* reflects the practice of the CAPP Reserves Committee and is also broadly comparable with that used by BP in its *Statistical Review of World Energy*, 2009 and by *World Oil* in its annual compilation of *Estimated Proven World Reserves*. BP states that it includes 'an official estimate of 22.0 billion barrels for oil sands under active development', whilst *World Oil* states that its 'oil sands reserve estimate is based on 50 years times current production capacity'.

The quantities of oil sands/bitumen included in Canada's proved reserves adopted for the present Survey correspond with 'remaining established reserves' of 'developed non-conventional oil' at end-2008 published by CAPP in its *Statistical Handbook* and included by the Reserves Committee of CAPP in its 2008 Report. 'Established reserves' are defined by CAPP as 'those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production, plus that judgement portion of contiguous recoverable reserves that are interpreted to exist, from geological, geophysical or similar information, with reasonable certainty'. 'Developed synthetic crude oil and bitumen reserves' are defined by CAPP as 'those recoverable from developed experimental/demonstration and commercial projects'.

Canada is the world leader in the production of oil from deposits of oil sands. The estimated ultimately recoverable resource from this 'newly conventional' supply is 55 billion cubic metres, second only to Saudi Arabia - see Chapter 4: Natural Bitumen and Extra-Heavy Oil.

According to *Oil & Gas Journal* (OGJ), Canada had 173.6 billion barrels of proven oil reserves as of the beginning of 2012. Canada controls the third-largest amount of proven reserves in the world, after Saudi Arabia and Venezuela. Among the top ten reserve-holders, the only other state that is not a member of the Organization of the Petroleum Exporting Countries (OPEC) is Russia. Canada's proven oil reserve levels have been stagnant or slightly declining since 2003, when they increased by an order of magnitude after oil sands resources were deemed to be technically and economically recoverable. The oil sands now account for approximately 170 billion barrels, or 98 percent, of Canada's oil reserves. Aside from other reserves in conventional onshore and offshore producing areas, additional resources are known to be under the Beaufort Sea in the Arctic, off the Pacific coast, and in the Gulf of St. Lawrence.

Canada produced almost 3.7 million barrels per day (bbl/d) of total oil in 2011, an increase of nearly 200 thousand bbl/d from 2010. Of this, 2.9 million bbl/d was crude oil and a small amount of lease condensate.

Oil production in Canada comes from three principal sources: the oil sands of Alberta, the conventional resources in the broader Western Canada Sedimentary Basin (WCSB), and the offshore oil fields in the Atlantic. Production from the oil sands accounted for over half of Canadian oil output in 2011, a proportion that has steadily increased in recent decades. In total, Alberta was responsible for almost 75 percent of Canadian oil production in 2011, according to an analysis of data from Statistics Canada. Other noteworthy producing provinces are Saskatchewan, with almost 14 percent of national output from its share of the WCSB, and offshore areas of Newfoundland and Labrador. Production in conventional offshore reserves off of the eastern provinces comes from mature oilfields, with few opportunities to mitigate decline rates. Accordingly, western provinces are expected to comprise an increasing proportion of overall Canadian oil production in the future.

Chad

Proved recoverable reserves (crude oil and NGLs, million barrels)	1 500
2011 production (crude oil and NGLs, thousand b/d)	43
R/P ratio (years)	34.3
Year of first commercial production	2003

The West African republic of Chad joined the ranks of the world's crude oil producers in July 2003, after the construction of a 1 070 km export pipeline from the oil fields in the Doba Basin of southern Chad through Cameroon to a new terminal at Kribi. The development of the Doba Basin fields (in the initial stages, Bolobo, Komé and Miandoum, followed in 2005-2007 by Nya Moundouli and Maikeri) and the pipeline is handled by a consortium consisting of ExxonMobil (40%), Petronas, the Malaysian state oil company (35%), and ChevronTexaco (25%).

Chad ranks as the tenth-largest oil reserve holder among African countries, with 1.5 billion barrels of proven reserves as of January 1, 2013, according to the *Oil and Gas Journal*. Crude oil production in Chad was an estimated 115,000 barrels per day (bbl/d) in 2011 and 105,000 bbl/d in 2012. Almost all of this was exported via the Chad-Cameroon Pipeline.

China

Proved recoverable reserves (crude oil and NGLs, million barrels)	20 400
2011 production (crude oil and NGLs, thousand b/d)	1492
R/P ratio (years)	13.0
Year of first commercial production	1939

The first significant oil find was the Lachunmia field in the north-central province of Gansu, which was discovered in 1939. An extensive exploration programme, aimed at self-sufficiency in oil, was launched in the 1950s; two major field complexes were discovered: Daqing (1959) in the northeastern province of Heilongjiang and Shengli (1961) near the Bo Hai gulf.

China's reserves remain a state secret, and thus it is necessary to have recourse to published sources. It is worth noting that OGJ has recently raised its estimate substantially, quoting 20 350 million barrels as at 1 January 2010.

China's oil reserves are by far the largest of any country in Asia: oil output is on a commensurate scale. According to *Oil & Gas Journal* (OGJ), China holds 20.4 billion barrels of proven oil reserves as of January 2012, up over 4 billion barrels from three years ago and the highest in the Asia-Pacific region. China's largest and oldest oil fields are located in the northeast region of the country. China produced an estimated 4.3 million barrels per day (bbl/d) of total oil liquids in 2011, of which 95 percent was crude oil. China's oil production is forecast to rise by about 170 thousand bbl/d to nearly 4.5 million bbl/d by the end of 2013. Over the longer term, EIA predicts a flatter incline for China's production, reaching 4.7 million bbl/d by 2035. China's oil consumption growth eased in 2011 from record high growth of 10 percent in 2010, reflecting the impact of the most recent global financial and economic downturn. However, the country still consumed an estimated 9.8 million bbl/d of oil in 2011, up 400 thousand bbl/d, or over 4 percent from 9.4 million bbl/d in 2010. In 2009, China became the second largest net oil importer in the world behind the United States, with net total oil imports reaching 5.5 million bbl/d in 2011. China's oil demand growth, particularly for petroleum products, hinges on several factors such as domestic economic growth and trade, power generation, transportation sector shifts, and refining capabilities. EIA forecasts that China's oil consumption will continue to grow during 2012 and 2013 at a moderate pace. Even so, the anticipated oil growth of over 0.8 million bbl/d between 2011 and 2013 would represent 64 percent of projected world oil demand growth during the 2-year forecast period.

Colombia

Proved recoverable reserves (crude oil and NGLs, million barrels)	1 900
2011 production (crude oil and NGLs, thousand b/d)	2499
R/P ratio (years)	7.6
Year of first commercial production	1921

Initially, oil discoveries were made principally in the valley of the Magdalena. Subsequently, other fields were discovered in the north of the country (from the early 1930s), and in 1959 oil was found in the Putamayo area in southern Colombia, near the border with Ecuador. More recently, major discoveries have included the Caño Limón field near the Venezuelan frontier and the Cusiana and Cupiagua fields in the Llanos Basin to the east of the Andes.

However, the remaining proved reserves have been shrinking in recent years and, despite a modest rise in 2008, are still at a very low level in relation to production, according to the data provided to the Colombian WEC Member Committee by the Unidad de Planeación Minero Energético (UPME) of the Ministerio de Minas y Energía. This source quotes proved recoverable oil reserves as 1 458 million barrels, implying an R/P ratio of only 6.4. However, in January 2010 it was reported by ANH (the National Hydrocarbons Agency) that end-2008 reserves were some 1.7 billion barrels.

Colombia's oil production rose at a modest rate from 2003 to 2007, but increased by more than 10% in 2008.

According to The *Oil and Gas Journal* (OGJ), Colombia had about 2 billion barrels of proven crude oil reserves in 2012, up from 1.9 billion barrels in 2011. Colombia's increasing reserves are a result of the exploration of several new blocks that were auctioned in the last bidding round in 2010. Much of Colombia's crude oil production occurs in the Andes foothills and the eastern Amazonian jungles. Meta department, in central Colombia, is also an important production area, predominately of heavy crude oil, and its Llanos basin contains the Rubiales oilfield, the largest producing oil field in the country.

Colombia produced 923,000 barrels per day (bbl/d) of oil in 2011, up 35 percent from the 595,000 bbl/d produced in 2008. This rising production trend is continuing. Most recently, the Ministry of Mines and Energy reported that Colombian production reached 951,000 barrels per day in March 2012, and is expected to reach 1.5 bbl/d by 2020. Colombia consumed 298,000 bbl/d in 2011, allowing the country to export most its oil production.

Congo (Brazzaville)

Proved recoverable reserves (crude oil and NGLs, million barrels)	1 600
2011 production (crude oil and NGLs, thousand b/d)	111
R/P ratio (years)	14.4
Year of first commercial production	1957

After becoming a significant oil producer in the mid-1970s, Congo (Brazzaville) is now the fourth largest in sub-Saharan Africa. Most of the fields in current production are located in coastal waters. The average quality of oil output has improved over the years, aided by the coming on-stream of Elf's deep-water Nkossa field. The bulk of oil production is exported.

As of the end of 2011, Congo has proven oil reserves of 1.6 billion barrels, according to *Oil & Gas Journal* (OGJ), the fifth-largest proven reserves in Sub-Saharan Africa. In the late 1970s, Congo emerged as a significant oil producer. Production continued to expand considerably during the 1990s, but at the turn of the century, as oil fields reached maturity, production declined in 2001. However, from 2008 to 2010 oil production has increased every year as a result of several new projects coming online, mainly Congo's first deepwater field Moho-Bilondo. In 2010, Congo produced 311,000 bbl/d of total oil supply, surpassing the country's previous peak of 292,000 bbl/d in 2000. However, in 2011, as most of Congo's oil fields continued to age, total output fell by about 4 percent to 298,000 bbl/d, of which almost 10,000 bbl/d was natural gas liquids (NGLs) and the remainder was crude oil and lease condensate.The large offshore Moho-Bilondo oil field, operated by Total, is the chief contributor to the increase in production since 2008. It came online in April 2008 and reached plateau output at 90,000 bbl/d in June 2010, according to Total. Total has the majority operating interest of 53.5 percent, in addition to Chevron's 31.5 percent and SNPC's 15 percent. Moho-Bilondo is the country's first deepwater project and marks the largest successful expedition to tap into Congo's deepwater reserves. Additionally, three other oil fields, the Ikalou complex (6,700 bbl/d), Azurite (19,000 bbl/d), and Libondo (12,000 bbl/d), have come onstream since 2008, according to IHS Global Insight and reports from Total.

Denmark

Proved recoverable reserves (crude oil and NGLs, million barrels)	811
2011 production (crude oil and NGLs, thousand b/d)	10
R/P ratio (years)	27
Year of first commercial production	1972

Denmark's proved recoverable reserves are the fourth largest in Europe (excluding the Russian Federation). The Danish Energy Authority (DEA) does not employ the terms 'proved', 'probable' and 'additional' reserves, but uses the categories 'ongoing', 'approved', 'planned' and 'possible' recovery. The figure for proved reserves (129 million m3 or 811 million barrels) reported by the DEA to the Danish WEC Member Committee has been calculated as the sum of 'ongoing' and 'approved' reserves, while the figure for potential additional recovery from known resources has been calculated as the sum of 2 million m3 'planned' reserves and 68 million m3 'possible' reserves, for a total of 70 million m3 or 440 million barrels. The reserve numbers are the expected values in each category.

The Member Committee also reports 60 million m3 (377 million barrels) as estimated to be recoverable from presently undiscovered resources. Denmark's oil reserves and resources may be viewed against the background of its cumulative oil production to end-2008 of some 332 million barrels.

All the oil fields discovered so far are located in the North Sea. Out of 21 fields or areas with reserves in the ongoing/approved category, four (Dan, Halfdan, Skjold and South Arne) account for 75% of the total volume.

The principal fields in production are Halfdan, Dan, Valdemar, South Arne and Gorm, which together accounted for 78% of national oil output. Over 60% of Danish crude is exported, chiefly to other countries in Western Europe.

Ecuador

Proved recoverable reserves (crude oil and NGLs, million barrels)	7 200
2011 production (crude oil and NGLs, thousand b/d)	198
R/P ratio (years)	36.6
Year of first commercial production	1917

The early discoveries of oil (1913-1921) were made in the Santa Elena peninsula on the southwest coast. From 1967 onwards, numerous oil fields were discovered in the Amazon Basin in the northeast of the country, adjacent to the Putamayo fields in Colombia: these eastern (Oriente) fields are now the major source of Ecuador's oil production. The republic reactivated its membership of OPEC in October 2007, after suspending it in December 1992.

According to the *Oil & Gas Journal* (OGJ), Ecuador held proven oil reserves of 7.2 billion barrels as of the end of 2011, an increase from the year before. Ecuador claims the third-largest oil reserves in South America after Venezuela and Brazil. Most of Ecuador's oil reserves are in the Oriente Basin in the eastern part of the country, underlying the Amazon.

Ecuador produced an estimated 499,000 bbl/d of oil in 2011, almost all of which was crude. Ecuador's oil production has increased slightly since 2009, but remains below a 2006 peak of 536,000 bbl/d. Thus far in 2012, Ecuador's oil production has fluctuated around 500,000 bbl/d. State-owned companies produced over 70 percent of the country's crude in 2011, with the remainder attributable to fields operated by private companies.

Egypt (Arab Republic)

Proved recoverable reserves (crude oil and NGLs, million barrels)	4 400
2011 production (crude oil and NGLs, thousand b/d)	257
R/P ratio (years)	17.1
Year of first commercial production	1911

Egypt has the sixth largest proved oil reserves in Africa, with over half located in its offshore waters. The main producing regions are in or alongside the Gulf of Suez and in the Western Desert.

Egypt is a member of OAPEC, although its crude oil exports account for less than 10% of its production. Total oil output (including condensate and gas-plant LPGs) has been slowly increasing since 2005.

According to the *Oil and Gas Journal*'s January 2012 estimate, Egypt's proven oil reserves are 4.4 billion barrels, an increase from 2010 reserve estimates of 3.7 billion barrels. New discoveries have boosted oil reserves in recent years. In 2011, Egypt's total oil production averaged around 710,000 bbl/d, of which approximately 560,000 bbl/d was crude oil including lease condensates and the remainder natural gas liquids (NGLs).

After Egypt's production peak of over 900,000 bbl/d in the 1990s, output began to increasingly decline as oil fields maturedHowever, ongoing successful exploration has led to new production from smaller fields, and enhanced oil recovery (EOR) techniques in existing fields have eased the decline at aging fields. In addition, output of NGLs and lease condensate have increased as a result of expanding natural gas production and have offset some of the other declines in liquids production.

One of Egypt's challenges is to satisfy increasing domestic demand for oil in the midst of falling domestic production. Domestic oil consumption has grown by over 30 percent over the last decade, from 550,000 bbl/d in 2000 to 815,000 bbl/d in 2011.

Equatorial Guinea

Proved recoverable reserves (crude oil and NGLs, million barrels)	1 100
2011 production (crude oil and NGLs, thousand b/d)	91
R/P ratio (years)	12
Year of first commercial production	1992

The Alba offshore condensate field was discovered in 1984 near the island of Bioko, a province of Equatorial Guinea, by the American company Walter International. In 1996, four years after Alba was brought into production, Mobil and its U.S. partner United Meridian began producing from Zafiro, another offshore field. Output built up rapidly in subsequent years: crude oil production in Equatorial Guinea . exceeded 360 000 b/d in 2008.

According to the *Oil & Gas Journal*, Equatorial Guinea had proved oil reserves of 1.1 billion barrels as of January 2012. Latest EIA estimates show that Equatorial Guinea's total liquids supply was about 320,000 barrels per day (bbl/d) in 2011. Equatoguinean oil production originates almost entirely from the Zafiro, Ceiba, and Okume fields, while condensate production comes from the Alba field.

Equatorial Guinea's declining output is expected to reverse in 2012, driven by new production from the Aseng field that came on-stream November 2011. Shortly after its start, the field reached around 50,000 bbl/d as four subsea wells were brought online. According to the country's Ministry of Mines, Industry and Energy, production at Aseng, situated in Block 1 offshore Bioko Island, started seven months ahead of schedule and was 13 percent under budget. U.S.-based Noble Energy is the field's main operator and estimates a recovery of about 120 million barrels of liquids over the project's lifespan.

Nearly all of Equatorial Guinea's oil production is exported and the small amount of domestic consumption is met through imports of refined products, which was estimated at 1,000 bbl/d in 2010. The majority of the country's production is exported to markets in North America, Europe, and Asia. In 2010, the United States imported approximately 70,000 bbl/d of crude oil from Equatorial Guinea. Other major destinations for exports include Spain, Italy, and Canada.

Gabon

Proved recoverable reserves (crude oil and NGLs, million barrels)	3 700
2011 production (crude oil and NGLs, thousand b/d)	91
R/P ratio (years)	21
Year of first commercial production	1961

Extensive oil resources have been located, both on land and offshore. In terms of proved recoverable reserves,

According to the *Oil & Gas Journal* (OGJ), Gabon had 2 billion barrels of proven oil reserves as of the end of 2012, the fifth-largest in Sub-Saharan Africa after Nigeria, Angola, Sudan and South Sudan (combined), and most recently, Uganda. Most of Gabon's oil fields are located in the Port-Gentil area and are both onshore and offshore. The country's oil production has decreased by around one-third from its peak of 370,000 barrels per day (bbl/d) in 1997 to 244,000 bbl/d in 2012. Oil consumption has remained steadily low in Gabon, averaging around 14,000 bbl/d over the last decade. Therefore, more than 90 percent of output is exported, or around 250,000 bbl/d, on average over the last decade.

Historically, Gabon's oil production has been concentrated in one large oil field and supported by several smaller fields. As the largest field matured and production declined, a larger field would emerge and replace dwindling production. Dominant fields have included Gamba/Ivinga/Totou (1967-1973), Grondin Mandaros Area (1974-1988), and Rabi (1989-2010). Gabon's greatest success, the Rabi oil field, significantly boosted the country's total output in the 1990s and reached 217,000 bbl/d at its peak in 1997. Although Rabi is still one of Gabon's largest producing fields, it has matured and production has gradually declined to about 23,000 bbl/d in 2010. Since Rabi's descent, a new large field has not yet emerged, since recent exploration has yielded only modest finds.

Gabon ranks third largest in sub-Saharan Africa, after Nigeria and Angola.

Gabon was a member of OPEC from 1975 to 1995, when it withdrew on the grounds that it was unfair for it to be charged the same membership fee as the larger producers but not to have equivalent voting rights.

In recent years over 90% of Gabon's oil output has been exported, mainly to the USA.

India

Proved recoverable reserves (crude oil and NGLs, million barrels)	5 700
2011 production (crude oil and NGLs, thousand b/d)	280
R/P ratio (years)	20.3
Year of first commercial production	1890

For more than 60 years after its discovery in 1890, the Digboi oil field in Assam, in the northeast of the country, provided India with its only commercial oil production: this field was still producing in 2009, albeit at a very low level. Since 1960 numerous onshore discoveries have been made in the western, eastern and southern parts of India; the outstanding find was, however, made in offshore waters in 1974, when the Mumbai High oil and gas field was discovered. In 2008-2009 offshore fields provided 66% of national oil output.

Total production of oil (including gas-plant liquids) has fluctuated in recent years within a range of 36-38 million tonnes per annum. In 2008, India produced 34.0 million tonnes of crude oil, plus about 2 million tonnes of natural gasoline and a similar tonnage of gas-plant LPGs, all of which was used internally.

Cairn Energy has made 25 discoveries in Rajasthan (in India's northwest). Initial attention is being concentrated on the Mangala, Bhagyam and Aishwariya (MBA) oil fields. An eventual peak rate of 240 000 b/d is envisaged, subject to Government approval and additional investment.

India was the fourth largest consumer of oil and petroleum products after the United States, China, and Japan in 2011. It was also the fourth largest importer of oil and petroleum products. The high degree of dependence on imported crude oil has led Indian energy companies to attempt to diversify their supply sources. To this end, Indian national oil companies (NOCs) have purchased equity stakes in overseas oil and gas fields in South America, Africa, and the Caspian Sea region to acquire reserves and production capability. However, the majority of imports continue to come from the Middle East, where Indian companies have little direct access to investment.

According to the *Oil & Gas Journal*, India had 5.5 billion barrels of proved oil reserves at the end of 2012. About 53 percent of reserves are from onshore resources, while 47 percent are offshore reserves. Most reserves are found in the western part of India, particularly western offshore, Gujarat, and Rajasthan. The Assam-Arakan basin in the northeast part of the country is also an important oil-producing region and contains more than 10 percent of the country's reserves.

Indonesia

Proved recoverable reserves (crude oil and NGLs, million barrels)	3 900
2011 production (crude oil and NGLs, thousand b/d)	258
R/P ratio (years)	15.2
Year of first commercial production	1893

The first commercial discovery of oil was made in north Sumatra in 1885; subsequent exploration led to the finding of many more fields, especially in southern Sumatra, Java and Kalimantan.

After being a member since 1962, Indonesia suspended its OPEC membership in December 2008.

Indonesia ranked 20th among world oil producers in 2011 (21st for crude oil and condensate production), accounting for approximately 1 percent of the world's daily production of liquid fuels. With oil first discovered in 1885, the hydrocarbon sector became an important part of Indonesia's economy. The oil and gas industry, including refining, contributed approximately 7 percent to GDP in 2010, according to data from Indonesia's National Bureau of Statistics.

According to the *Oil & Gas Journal* (OGJ), Indonesia had 3.9 billion barrels of proven oil reserves as of January 2012. Total oil production continued to decline from a high of nearly 1.7 million barrels per day (bbl/d) in 1991 to just under 1.0 million bbl/d in 2011. Of this total, approximately 900,000 bbl/d was crude oil and lease condensate production. This fell short of the government's production goal of 945,000 bbl/d for that year (already reduced from an original target of 970,000 bbl/d). While production of refined petroleum products has increased since 1998, crude and condensate production has declined at an annual rate of 3.8 percent between 1998 and 2011.

Iran (Islamic Republic)

Proved recoverable reserves (crude oil and NGLs, million barrels)	151 200
2011 production (crude oil and NGLs, thousand b/d)	1 508
R/P ratio (years)	100
Year of first commercial production	1913

The first commercial crude oil discovered in Iran was at Masjid-i-Sulaiman in 1908. Further exploration in the next two decades resulted in the discovery of a number of major oil fields, including Agha Jari and Gach Saran. Fields such as these confirmed Iran in its role as a global player in the oil industry.

After many years as a major oil producer, the country's oil resources are still enormous: proved reserves, as reported for the present *Survey* by the Iranian WEC Member Committee, comprise 100.65 billion barrels of crude oil plus 36.96 billion barrels of NGLs. Total reported reserves are almost identical to those quoted by BP and closely in line with those given by other standard published sources (136.15-138.20), which is possibly somewhat surprising, in that several of these sources specifically exclude natural gas liquids from their compilations.

According to *Oil & Gas Journal*, Iran has nine percent of the world's total reserves and over 12 percent of OPEC reserves.

The Member Committee reports that approximately 14% of Iran's proved reserves of crude and 55% of its NGLs are located offshore. Iran was a founder member of OPEC in 1960. In 2008, about 60% of Iran's crude oil output of 4.1 million b/d was exported, mostly to Europe and Asia.

Over 50 percent of Iran's onshore oil reserves are confined to five giant fields, the largest of which are the Marun field (22 billion barrels), Ahwaz (18 billion barrels), and Aghajari (17 billion barrels). Of those onshore reserves, more than 80 percent are located in the south-western Khuzestan Basin near the Iraqi border. Iran's crude oil is generally medium in sulfur content and in the 28° to 35° API gravity range. According to FACTS Global Energy (FGE), Iran also possesses reserves in the Caspian Sea totaling approximately 100 million barrels. Iran faces continued depletion of its production capacity, as its fields have relatively high natural decline rates (8-13 percent), coupled with an already low recovery rate of around 20-30 percent. Sanctions and prohibitive contractual terms have impeded the necessary investment to halt this decline. Moreover, sanctions enacted in late 2011 and throughout 2012 have accelerated Iran's production capacity declines.

In 2012, Iran produced approximately 3.5 million barrels per day (bbl/d) of total liquids, of which roughly 3.0 million bbl/d was crude oil. The total production level in 2012 was about 17 percent lower than the production level of 4.2 million bbl/d in 2011, most of the drop is attributable to the imposition of sanctions. Condensate production totaled approximately 650 thousand bbl/d in 2011, according to Arab Oil and Gas Directory, of which 440 thousand bbl/d was marketed and 210 thousand bbl/d was mixed in with the crude oil.

Iran has 34 producing fields (22 onshore and 12 offshore), with onshore fields comprising more than 71 percent of total reserves. Currently, Iran's largest producing field is the onshore Ahwaz-Asmari field, followed by the Marun and Gachsaran fields, all of which are located in Khuzestan province.

Iraq

Proved recoverable reserves (crude oil and NGLs, million barrels)	115 000
2011 production (crude oil and NGLs, thousand b/d)	983
R/P ratio (years)	116
Year of first commercial production	1928

Crude oil deposits were discovered near Kirkuk in northern Iraq in 1927, with large-scale production getting under way in 1934-1935 following the construction of export pipelines to the Mediterranean. After World War II more oil fields were discovered and further export lines built. Proved reserves, as quoted by OAPEC, OPEC and most of the other standard published sources, remain at 115 billion barrels, third after Saudi Arabia and Iran in the Middle East, and indeed in the world. The only exception is *World Oil*, which since end-2006 has estimated Iraq's crude reserves at a somewhat higher level, currently 126 billion barrels.

Iraq was a founder member of OPEC in 1960 and it is also a member of OAPEC. Iraq revised its estimate of proven oil reserves from 115 billion barrels in 2011 to 141 billion barrels as of January 1, 2013, according to the *Oil and Gas Journal*. Iraq's resources are not evenly divided across sectarian-demographic lines. Most known hydrocarbon resources are concentrated in the Shiite areas of the south and the ethnically Kurdish region in the north, with few resources in control of the Sunni minority in central Iraq.

The majority of the known oil and gas reserves in Iraq form a belt that runs along the eastern edge of the country. Iraq has five super-giant fields (over 5 billion barrels) in the south that account for 60 percent of the country's proven oil reserves. An estimated 17 percent of oil reserves are in the north of Iraq, near Kirkuk, Mosul, and Khanaqin. Control over rights to reserves is a source of controversy between the ethnic Kurds and other groups in the area. The International Energy Agency (IEA) estimated that the Kurdistan Regional Government (KRG) area contained 4 billion barrels of proven reserves. However, this region is now being actively explored, and the KRG stated that this region could contain 45 billion barrels of unproven oil resources.

Iraqi crude oil production averaged 3 million barrels per day (bbl/d) in 2012, and Iraq passed Iran as OPEC's second largest crude oil producer at the end of the year. About three-fourths of Iraq's crude oil production comes from the southern fields, with the remainder primarily from the northern fields near Kirkuk. The majority of Iraqi oil production comes from just three giant fields: Kirkuk, the North Rumaila field in southern Iraq, and the South Rumaila field.

Italy

Proved recoverable reserves (crude oil and NGLs, million barrels)	559
2011 production (crude oil and NGLs, thousand b/d)	38
R/P ratio (years)	14.3
Year of first commercial production	1861

Like France and Germany, Italy has a long history of oil production, albeit on a very small scale until the discovery of the Ragusa and Gela fields in Sicily in the mid-1950s. Subsequent exploration led to the discovery of a number of fields offshore Sicily, several in Adriatic waters and others onshore in the Po Valley Basin.

The Italian WEC Member Committee reports that proved recoverable reserves at end-2008 were 62 million tonnes (equivalent to approximately 434 million barrels), out of a remaining proved amount in place of 128 million tonnes. Recoverable reserves at lower levels of probability comprised 93 million tonnes (651 million barrels) of probable reserves and 104 million tonnes (728 million barrels) of possible reserves. The Member Committee also estimates that undiscovered *in situ* oil resources are in the order of 55 to 370 million tonnes (in round terms, some 400 to 2 700 million tonnes).

Kazakhstan

Proved recoverable reserves (crude oil and NGLs, million barrels)	30 000
2011 production (crude oil and NGLs, thousand b/d)	586
R/P ratio (years)	51.0
Year of first commercial production	1911

Kazakhstan's oil resources are the largest of all the former Soviet republics (apart from the Russian Federation).

The Member Committee reports that more than 90% of the republic's oil reserves are concentrated in its 15 largest oil fields, namely Tengiz, Kashagan, Karachaganak, Uzen, Zhetybai, Zhanazhol, Kalamkas, Kenkiyak, Karazhanbas, Kumkol, Buzachi Severnye, Alibekmola, Prorva Tsentalnaya and Vostochnaya, Kenbai, Korolyovskoye.

Output of oil more than doubled between 2000 and 2008 to some 72 million tonnes (1 554 000 b/d), including condensate and other NGLs. In 2007, exports accounted for about 92% of the republic's oil production.

Kazakhstan's proven oil reserves were estimated at 30 billion barrels by the *Oil and Gas Journal* in January 2012. The country's main oil reserves are located in the western part of the country, where the 5 largest onshore oil fields (Tengiz, Karachaganak, Aktobe, Mangistau, and Uzen) are located. These onshore fields account for about half of current proven reserves, while the offshore Kashagan and Kurmangazy oil fields, in Kazakhstan's sector of the Caspian Sea, are estimated to contain at least 14 billion barrels, with Kashagan accounting for around 9 billion barrels.

Kazakhstan's oil production reached 1.64 million barrels per day (bbl/d) in 2011; however, data for 2012 thus far indicate that liquids production in Kazakhstan will be slightly lower for the year at 1.60 million bbl/d. Kazakhstan's production has seen an impressive expansion since 1995 with the help from foreign oil companies. It surpassed the 1.0 million bbl/d production level in 2003 and steadily grew to be the second-largest oil producer in the Former Soviet Union, second only to Russia.

Kuwait

Proved recoverable reserves (crude oil and NGLs, million barrels)	101 500
2011 production (crude oil and NGLs, thousand b/d)	984
R/P ratio (years)	14
Year of first commercial production	1946

Note: Kuwait data include its share of Neutral Zone.

The State of Kuwait is one of the most oil-rich countries in the world: it currently ranks fourth in terms of the volume of proved reserves. Oil was discovered at Burgan in 1938 and commercial production commenced after World War II. Seven other oil fields were discovered during the next 15 years and output rose rapidly. Kuwait was one of the founder members of OPEC in 1960 and is also a member of OAPEC.

According to *Oil & Gas Journal*, as of January 2011, Kuwait's territorial boundaries contained an estimated 101.5 billion barrels (bbl) of proven oil reserves, roughly 7 percent of the world total. Additional reserves are held in the Partitioned Neutral Zone (aka Divided Zone), which Kuwait shares on a 50-50 basis with Saudi Arabia. The Neutral Zone holds an additional 5 billion barrels of proven reserves, bringing Kuwait's total oil reserves to 104 billion barrels. These reserve estimates have been openly questioned by some analysts and a number of Kuwaiti parliamentarians, with some putting reserves as low as 48 billion barrels.

In 2010, Kuwait's total oil production was approximately 2.5 million barrels per day (bbl/d), including its share of approximately 250,000 bbl/d production from the PNZ. Of the country's 2010 production, approximately 2.3 million bbl/d was crude and 200,000 bbl/d was non-crude liquids. Slightly over half of Kuwaiti crude production in 2010 came from the southeast of the country, largely from the Burgan field; production from the north has increased to approximately 800,000 bbl/d. As a member of OPEC, Kuwait's total production is constrained by the organization's production targets, which in 2010 meant the country maintained about 320,000 bbl/d of spare crude oil production capacity. In early 2011, as one of the few OPEC members with spare capacity, Kuwait has increased oil production to compensate for the loss of Libyan supplies

Libya/GSPLAJ

Proved recoverable reserves (crude oil and NGLs, million barrels)	47 100
2011 production (crude oil and NGLs, thousand b/d)	1 546
R/P ratio (years)	30
Year of first commercial production	1961

Libya accounts for about one-third of Africa's proved oil reserves. The majority of the known oil reservoirs lie in the northern part of the country; there are a few offshore fields in western waters near the Tunisian border. The crudes produced are generally light (over 35o API) and very low in sulphur.

Libya joined OPEC in 1962 and is also a member of OAPEC. It exported over 80% of its oil output in 2008, mostly to Western Europe.

According to *Oil and Gas Journal* (OGJ), Libya had total proven oil reserves of 47.1 billion barrels as of January 2012 – the largest endowment in Africa, and among the ten largest globally. Close to 80 percent of Libya's proven oil reserves are located in the eastern Sirte basin, which also accounts for most of the country's oil output. Libyan oil is generally light (high API gravity) and sweet (low sulfur content).

Prior to the onset of hostilities, Libya had been producing an estimated 1.65 million barrels per day (bbl/d) of mostly light, sweet crude oil. Libya's production capacity had increased over the previous decade, from 1.4 million bbl/d in 2000 to 1.8 million bbl/d in 2010, but still remained well below peak levels of over 3 million bbl/d achieved in the late 1960s. Though Libya produced below nameplate capacity, output exceeded the country's OPEC target of 1.47 million bbl/d. Libya also produced an estimated 140 thousand bbl/d of non-crude liquids, which include lease condensate and natural gas plant liquids.

Malaysia

Proved recoverable reserves (crude oil and NGLs, million barrels)	4 000
2011 production (crude oil and NGLs, thousand b/d)	229
R/P ratio (years)	17.4
Year of first commercial production	1913

Oil was discovered at Miri in northern Sarawak in 1910, thus ushering in Malaysia's long history as an oil producer. However, it was not until after successful exploration in offshore areas of Sarawak, Sabah and peninsular Malaysia in the 1960s and 1970s that the republic really emerged as a major producer.

For a number of years, there appears to have been considerable uncertainty with regard to the level of Malaysia's proved oil reserves.

According to the *Oil & Gas Journal* (OGJ), Malaysia held proven oil reserves of 4 billion barrels as of January 2011. Nearly all of Malaysia's oil comes from offshore fields. The continental shelf is divided into 3 producing basins: the Malay basin offshore peninsular Malaysia in the west and the Sarawak and Sabah basins in the east. Most of the country's oil reserves are located in the Malay basin and tend to be of high quality. Malaysia's benchmark crude oil, Tapis Blend, is of the light and sweet variety with an API gravity of 44° and sulfur content of 0.08 percent by weight.

Total oil production in 2011 was an estimated 630,000 barrels per day (bbl/d), compared with 665,000 in 2010, of which about 83 percent was crude oil. More than half of total Malaysian oil production currently comes from the Tapis field in the offshore Malay basin. Malaysian oil production has been gradually decreasing since reaching a peak of 862,000 bbl/d in 2004 due to its maturing reservoirs. Malaysia consumes the majority of its oil production and domestic consumption has been rising as production has been falling. The government is focused on opening up new investment opportunities by enhancing output from existing fields and developing new fields in deepwater areas offshore Sarawak and Sabah.

Mexico

Proved recoverable reserves (crude oil and NGLs, million barrels)	10 025
2011 production (crude oil and NGLs, thousand b/d)	930
R/P ratio (years)	10.9
Year of first commercial production	1904

Mexico's massive oil resource base has given rise to one of the world's largest oil industries, centred on the national company Petróleos Mexicanos (Pemex), founded in 1938.

Commercial oil production began in 1904 and by 1918 the republic was the second largest producer in the world. The discovery and development of oil fields along the eastern coast of the country - in particular, the offshore reservoirs off the coast of the State of Campeche - have brought annual production up to its present level.

Mexico produced an average of 2.96 million barrels per day (bbl/d) of total oil liquids during 2011. Crude oil accounted for 2.55 million bbl/d, or 86 percent of total output, with the remainder attributable to lease condensate, natural gas liquids, and refinery processing gain. Mexico's oil production has been relatively stagnant since 2009, and the minor decreases that have occurred mark an improvement from the more drastic declines that commenced around the middle of the last decade. Mexico is a large but declining net crude exporter, and is a net importer of refined petroleum products. Its most important trading partner is the United States, which is the destination for most of its crude oil exports and the source of most of its refined product imports.

According to the *Oil & Gas Journal* (OGJ), Mexico had 10.2 billion barrels of proven oil reserves as of the end of 2011. Most reserves consist of heavy crude oil varieties, with the largest concentration of reserves occurring offshore in the southern part of the country, especially in the Campeche Basin. There are also sizable reserves in Mexico's onshore basins in the northern parts of the country.

Nigeria

Proved recoverable reserves (crude oil and NGLs, million barrels)	37 200
2011 production (crude oil and NGLs, thousand b/d)	881
R/P ratio (years)	42.2
Year of first commercial production	1957

Nigeria's proved oil reserves are the second largest in Africa, after those of Libya. The country's oil fields are located in the south, mainly in the Niger delta and offshore in the Gulf of Guinea. Nigeria has been a member of OPEC since 1971.

Nigeria exports much the greater part of its crude oil output, chiefly to North America and Western Europe, and imports the bulk of its refined product requirements.

According to *Oil and Gas Journal* (OGJ), Nigeria has an estimated 37.2 billion barrels of proven oil reserves as of the end of 2011. The majority of reserves are found along the country's Niger River Delta and offshore in the Bight of Benin, the Gulf of Guinea, and the Bight of Bonny. Current exploration activities are mostly focused in the deep and ultra-deep offshore with some activities in the Chad basin, located in the northeast of the country.

The government hopes to increase proven oil reserves to 40 billion barrels in the next few years; however, exploration activity levels are at their lowest in a decade and only three exploratory wells were drilled in 2011, compared to over 20 in 2005. Rising security problems related to oil theft, pipeline sabotage, and piracy in the Gulf of Guinea, coupled with investment uncertainties surrounding the long-delayed PIB, have curtailed oil exploration projects and impeded the country from reaching its ongoing target to increase production to 4 million bbl/d.

Norway

Proved recoverable reserves (crude oil and NGLs, million barrels)	5 320
2011 production (crude oil and NGLs, thousand b/d)	675
R/P ratio (years)	7.8
Year of first commercial production	1971

Starting with the discovery of the Ekofisk oil field in 1970, successful exploration in Norway's North Sea waters has brought the country into No. 1 position in Europe (excluding the Russian Federation), in terms of oil in place, proved reserves and production.

On the basis of data published by the Norwegian Petroleum Directorate (NPD), total remaining oil reserves at end-2008 amounted to 7 491 million barrels, comprised of 919 million m3 (5 780 million barrels) of crude oil, 120 million tonnes (1 440 million barrels) of NGLs and 43 million m3 (270 million barrels) of condensate. 'Remaining reserves' are defined as 'remaining recoverable petroleum resources in deposits for which the authorities have approved the plan for development and operation (PDO) or granted a PDO exemption'. They 'also include petroleum resources in deposits that the licensees have decided to develop, but for which the authorities have not as yet completed processing of either a PDO approval or a PDO exemption'.

In addition to 'remaining reserves', the NPD reports 'contingent resources', defined as 'discovered quantities of petroleum for which no development decision has yet been made', and 'potential from improved recovery': together these represent 688 million m3 (4 327 million barrels) of crude oil, 42 million tonnes (502 million barrels) of NGLs and 32 million m3 (201 million barrels) of condensate - a total additional recoverable resource of just over 5 billion barrels. Over and above these amounts, the NPD estimates that Norway possesses about 9.6 billion barrels of 'undiscovered resources', comprising 1 260 million m3 (7 925 million barrels) of crude oil and 265 million m3 (1 667 million barrels) of condensate. Undiscovered resources include 'petroleum volumes expected to be present in defined plays, confirmed and unconfirmed, but which have not yet been proven by drilling'.

As a frame of reference, it may be noted that Norway's cumulative oil production to the end of 2008 consisted of 3 405 million m3 (21 417 million barrels) of crude oil, 116 million tonnes (1 386 million barrels) of NGLs and 96 million m3 (604 million barrels) of condensate, for a grand total of 23 407 million barrels of oil, compared with its total remaining discovered and undiscovered oil resources of 22 106 million barrels.

Following 16 years of unremitting growth, Norwegian oil production levelled off in the late 1990s and since 2001 has followed a gently downward path. Nearly 84% of Norway's 2008 crude oil production of some 2.1 million b/d was exported, mostly to Western European countries, Canada and the USA.

According to The *Oil and Gas Journal* (OGJ), Norway had 5.32 billion barrels of proven oil reserves as of January 1, 2012, the largest oil reserves in Western Europe. All of Norway's oil reserves are located offshore on the Norwegian Continental Shelf (NCS), which is divided into three sections: the North Sea, the Norwegian Sea and the Barents Sea. The bulk of Norway's oil production occurs in the North Sea, with smaller amounts in the Norwegian Sea and new exploration and production activity occurring in the Barents Sea.

In June 2012, Norway's oil and gas production faced being completely shut-in when an offshore workers strike began over employers' plans to increase the retirement age from 62 to 67. Government intervention stopped the strike, during which cutbacks to the country's production affected 15 percent of oil and 7 percent of gas production, according to Statoil.

In 2011, Norway produced 2.0 million bbl/d of petroleum and other fuels, of which about 87 percent was crude oil. Norway's petroleum production has been gradually declining since 2001 as oil fields have matured. The NPD expects that production will continue to decline slowly over the next few years, and that in the longer term the number and size of new discoveries will be a critical factor in maintaining production levels. Currently, seventy fields are in production on the NCS. The three largest producing oil fields are Ekofisk, which produced 162,000 bbl/d in 2010; Grane, which produced 166,000 bbl/d; and Troll, which produced 118,000 bbl/d.

According to the International Energy Agency (IEA), Norway exported an estimated 1.45 million bbl/d of crude oil in 2011, of which 90 percent went to OECD European countries. The top five importers of Norwegian oil (crude plus products) in 2011 were the United Kingdom (52 percent), the Netherlands (18 percent), the United States (10 percent), France (8 percent), and Germany (5 percent).

Oman

Proved recoverable reserves (crude oil and NGLs, million barrels)	5 500
2011 production (crude oil and NGLs, thousand b/d)	308
R/P ratio (years)	17.7
Year of first commercial production	1967

In a regional context, this is one of the less well-endowed Middle East countries but its proved reserves are, nevertheless, quite substantial (5.5 billion barrels at end-2008, according to OAPEC). Other published sources of reserves data generally concur.

Three oil fields were discovered in the northwest central part of Oman in the early 1960s; commercial production began after the construction of an export pipeline. Many other fields have subsequently been located and brought into production, making the country a significant oil producer and exporter; it has, however, never joined OPEC or OAPEC.

According to *Oil & Gas Journal* (OGJ), Oman has total proven reserves of 5.5 billion barrels of oil as of January 2012. Oman's reserves are found mainly in the north and central onshore areas, comprised of disparate clusters of smaller fields. This geological composition makes production costs some of the highest in the region. The transition into secondary and tertiary extraction techniques will only increase these costs further. Oman has thus far implemented a successful program to reverse the decline in production experienced for most of the past decade, deploying some of the most sophisticated methods of enhanced oil extraction.

Oman produced 889,000 barrels per day (bbl/d) of total petroleum liquids in 2011, 886,000 bbl/d of which was crude oil. Oman is expected to produce 915,000 bbl/d for 2012 after its Harweel Enhanced Oil Recovery project adds approximately 30,000 bbl/d to that total. Oil production in Oman has increased by more than 24 percent over the past four years, from a low of 714,000 bbl/d in 2007. PDO owns a concession which previously encompassed most of the country (Block-6), which has since been broken up and parceled out in successive bidding rounds. Much of the production growth has come from the success of international firms in developing former portions of Block-6.

Papua New Guinea

Proved recoverable reserves (crude oil and NGLs, million barrels)	70
2011 production (crude oil and NGLs, thousand b/d)	7
R/P ratio (years)	10
Year of first commercial production	1992

Five sedimentary basins are known to exist in PNG. Most exploration activity, and all hydrocarbon discoveries to date, have occurred in the Papuan Basin in the southern part of the mainland. After many campaigns of exploration (starting in 1911), the first commercial discoveries were eventually made during the second half of the 1980s. Commercial production began in 1992 after an export pipeline had been built.

Peru

Proved recoverable reserves (crude oil and NGLs, million barrels)	582
2011 production (crude oil and NGLs, thousand b/d)	48
R/P ratio (years)	12.1
Year of first commercial production	1883

Peru is probably the oldest commercial producer of oil in South America.

According to the *Oil and Gas Journal*, Peru had 582 million barrels of proven oil reserves in January 2012, up from 533 million barrels in January 2011. Peru has added approximately 50 million barrels of reserves in each of the past two years.

Much of Peru's proven oil reserves are onshore, and the majority of these onshore reserves are in the Amazon region. Eleven important new hydrocarbon discoveries have occurred in just the past few years. In 2005, Peru's first offshore oil discovery occurred in the San Pedro well in Block Z-2B, where light oil was found. The largest recent discoveries have been in the offshore Talara and onshore Maranon basins, where 1.4 billion and 970 million barrels, respectively, of recoverable oil have been discovered.

Oil companies have leased at least 41 percent of the Peruvian Amazon for oil and gas drilling and could soon hold 70 percent, including areas that are officially protected for the indigenous people, as more contracts are signed with foreign investors. The current exploration boom is the second to hit this region, following an initial surge of exploration in the 1970s and 1980s.

According to EIA estimates, Peru produced 153,800 barrels per day (bbl/d) of total oil in 2011, down slightly from the 158,300 bbl/d produced in 2010, and an increase of 60 percent from the 99,600 bbl/d produced in 2000. According to Perupetro, of the 153,000 bbl/d produced in 2011, 46 percent was crude oil and 54 percent was natural gas liquids (NGL).

Peru is a net oil importer of both crude and products as domestic petroleum consumption is increasing and reached 189,000 bbl/d in 2010. Much of Peru's crude oil imports come from Ecuador.

Qatar

Proved recoverable reserves (crude oil and NGLs, million barrels)	25 400
2011 production (crude oil and NGLs, thousand b/d)	472
R/P ratio (years)	53.4
Year of first commercial production	1949

In regional terms, Qatar's oil resources are relatively small, its strength being much more in natural gas. In the 1930s interest in its prospects was aroused by the discovery of oil in neighbouring Bahrain. The Dukhan field was discovered in 1939 but commercialisation was deferred until after World War II. During the period 1960-1970, several offshore fields were found, and Qatar's oil output grew steadily. It joined OPEC in 1961 and also became a member of OAPEC.

According to *Oil & Gas Journal*, as of January 1, 2013, Qatar has 25.4 billion barrels of proven oil reserves, ranked 13th in the world. According to official OPEC data, Qatar was the 10th largest total liquids exporter among the 12 OPEC members in 2011. The onshore Dukhan field, located along the west coast of the peninsula, is the country's oldest producing oil field, although it has been surpassed in production by the offshore Al-Shaheen field. While the government's energy policy is focused on gas production and exports, Qatar is taking measures to extend the life of its oil fields through enhanced oil recovery (EOR) techniques.

In 2011, Qatar consumed approximately 183,000 bbl/d of petroleum. Although still relatively small compared to total production levels, consumption has more than tripled since 2000. FACTS Global Energy forecasts Qatar's oil product consumption to grow by an average annual rate of about five percent between 2010 and 2015. Qatar's increased petroleum consumption rate is due to its rapidly growing economy, particularly the associated growth of transportation sector demand.

Romania

Proved recoverable reserves (crude oil and NGLs, million barrels)	396
2011 production (crude oil and NGLs, thousand b/d)	32
R/P ratio (years)	12.2
Year of first commercial production	1857

Despite being one of Europe's oldest oil producers, Romania still possesses substantial oil resources. The Romanian WEC Member Committee, quoting the National Agency for Mineral Resources, reports recoverable reserves of 54 million tonnes of crude plus 0.54 million tonnes of NGLs. The estimated additional recoverable reserves reported comprise 9 million tonnes of 'probable' reserves and 6 million tonnes in the 'possible' category, together with minor tonnages of NGLs.

The principal region of production has long been the Ploesti area in the Carpathian Basin to the northwest of Bucharest, but a new oil province has come on the scene in recent years with the start-up of production from two offshore fields (West and East Lebada) in the Black Sea. Within the figure of proved recoverable reserves given above, 2.2 million tonnes of crude oil is reported to be located in offshore waters. In national terms, oil output (including NGLs) has been gradually contracting since around 1995.

Russian Federation

Proved recoverable reserves (crude oil and NGLs, million barrels)	60 000
2011 production (crude oil and NGLs, thousand b/d)	3730
R/P ratio (years)	16.8
Year of first commercial production	NA

The Russian oil industry has been developing for well over a century, much of that time under the Soviet centrally planned and state-owned system, in which the achievement of physical production targets was of prime importance. After World War II, hydrocarbons exploration and production development shifted from European Russia to the east, with the opening-up of the Volga-Urals and West Siberia regions.

Production levels in Russia advanced strongly from the mid-1950s to around 1980 when output levelled off for a decade. After a sharp decline in the first half of the 1990s, oil production levelled off again, at around 305 million tonnes/yr, until an upward trend starting in 2000 brought the total up to 488.5 million tonnes (nearly 9.9 million b/d) in 2008. Russia exports more than half of its oil production.

Russia's proven oil reserves were 60 billion barrels as of January 2012, according to the *Oil and Gas Journal*. Most of Russia's resources are located in Western Siberia, between the Ural Mountains and the Central Siberian Plateau and in the Volga-Urals region, extending into the Caspian Sea. Eastern Siberia holds some reserves, but the region has had little exploration.

In 2011 Russia produced an estimated 10.2 million bbl/d of total liquids (of which 9.8 million bbl/d was crude oil), and consumed roughly 3.1 million bbl/d. Russia exported around 7 million bbl/d in 2011 including roughly 4.9 million bbl/d of crude oil and the remainder in products. Russia's pipeline oil exports fall under the jurisdiction of the state-owned pipeline monopoly, Transneft. Monthly data thus far in 2012 show that Russia's total liquids production has consistently remained above 10.0 million bbl/d.

Russia has 40 oil refineries with a total crude oil processing capacity of 5.4 million bbl/d, according to *Oil and Gas Journal*. Rosneft, the largest refinery operator, controls 1.3 million bbl/d and operates Russia's largest refinery, the 385,176-bbl/d Angarsk facility. Other companies with sizeable refining capacity in Russia include LUKoil (975,860 bbl/d), and TNK-BP (690,000 bbl/d).

In 2011, Russia exported roughly 7.1 million bbl/d of total liquids. Data for 2011 show that Russia exported about 4.8 million bbl/d of crude oil in 2011. The majority of Russian exports (78 percent) are destined for European markets, particularly Germany, Netherlands, and Poland. Around 16 percent of Russia's oil exports go to Asia, while 6 percent are exported to North and South America. Russia's main export blend is the Urals blend and it is a mixture of mostly Russian crudes of varying quality and smaller amounts of Azeri and Kazakh crudes.

Saudi Arabia

Proved recoverable reserves (crude oil and NGLs, million barrels)	265 400
2011 production (crude oil and NGLs, thousand b/d)	3864
R/P ratio (years)	68.8
Year of first commercial production	1938

NOTE: Saudi Arabia data include its share of the Neutral Zone, together with production from the Abu Safa oilfield (jointly owned with Bahrain).

The Kingdom has been a leading oil producer for more than 40 years and currently has by far the world's largest proven reserves of oil: at end-2008 these represented about 21% of the global total. The first major commercial discovery of oil in Saudi Arabia was the Dammam field, located by Aramco in 1938; in subsequent years the company discovered many giant fields, including Ghawar (1948), generally regarded as the world's largest oil field, and Safaniyah (1951), the world's largest offshore field.

Saudi Arabia was a founder member of OPEC and also of OAPEC. It exports about 80% of its crude oil output; major destination regions are Asia, North America and Western Europe.

According to the *Oil and Gas Journal*, Saudi Arabia contains approximately 265 billion barrels of proven oil reserves (plus 2.5 billion barrels in the Saudi-Kuwaiti shared Neutral Zone) as of January 1, 2013, amounting to slightly less than one-fifth of proven, conventional world oil reserves. Although Saudi Arabia has about 100 major oil and gas fields, over half of its oil reserves are contained in only eight fields. The giant Ghawar field, the world's largest oil field with estimated remaining reserves of 70 billion barrels, has more proven oil reserves than all but seven other countries.

Saudi Arabia is the largest oil consuming nation in the Middle East. Saudi Arabia consumed approximately 3 million barrels per day (bbl/d) of oil in 2012, almost double 2000 levels, because of strong industrial growth and subsidized prices. Contributing to this growth is rising direct burn of crude oil for power generation, which reaches 1 million bbl/d during summer months, and the use of natural gas liquids (NGL) for petrochemical production. Khalid al-Falih warned that domestic liquids demand was on a pace to reach over 8 million bbl/d (oil equivalent) by 2030 if there were no improvements in energy efficiency.

Saudi Arabia produced on average 11.6 million bbl/d of total petroleum liquids in 2012. In addition to 9.8 million bbl/d of crude oil, Saudi Arabia produced 1.8 million bbl/d of natural gas liquids (NGL) and other liquids. Saudi Arabia, a leading world producer of NGL, has experienced a rise in demand for NGL from developing countries, including India (the leading export destination), where it is used for cooking and transportation.

Sudan

Proved recoverable reserves (crude oil and NGLs, million barrels)	5 000
2011 production (crude oil and NGLs, thousand b/d)	480
R/P ratio (years)	38.1
Year of first commercial production	1992

Several oil fields, including Heglig and Unity, were discovered in south-central Sudan in the early 1980s but terrorist action forced the companies concerned to withdraw. Other foreign companies started to undertake exploration and development activities some 10 years later.

Commercial production from the Heglig field began in 1996, since when Sudan has developed into an oil producer and exporter of some significance, a key factor being the construction of a 250 000 b/d export pipeline to the Red Sea.

Most of Sudan's oil is produced in the South, but the pipeline, refining and export infrastructure is in the North of the country. According to the *Oil & Gas Journal* (OGJ), Sudan and South Sudan had five billion barrels of proved oil reserves as of January 2012, up from an estimated 563 million barrels in 2006. Other analysts put reserve estimates as low as 4.2 billion barrels (Wood Mackenzie) or as high as 6.7 billion barrels (BP 2011 Statistical Review). The majority of reserves are located in the oil-rich Muglad and Melut Basins. Oil produced in these basins and nearby fields is transported through two main pipelines that stretch from the landlocked South to Port Sudan. Due to civil conflict, oil exploration prior to independence was mostly limited to the central and south-central regions of the unified Sudan. Natural gas associated with oil production is mostly flared or re-injected. Despite known reserves of 3 trillion cubic feet (Tcf), gas development has taken the backseat to oil development and gas exploration has been limited.

Syria (Arab Republic)

Proved recoverable reserves (crude oil and NGLs, million barrels)	2 459
2011 production (crude oil and NGLs, thousand b/d)	351
R/P ratio (years)	19.1
Year of first commercial production	1968

After many years (1930-1951) of unsuccessful exploration, oil was eventually found in 1956 at Karachuk. This and other early discoveries mostly consisted of heavy, high-sulphur crudes. Subsequent finds, in particular in the Deir al-Zor area in the valley of the Euphrates, have tended to be of much lighter oil.

National oil output has declined in recent years; according to the National Bureau of Statistics. Syria is a member of OAPEC: exports accounted for about 40% of its crude oil production in 2007, with its principal customers being Germany, Italy and France.

The *Oil & Gas Journal* (OGJ) estimated Syria's proved reserves at roughly 2.5 billion barrels as of January 1, 2013, a total larger than all of Syria's neighbours except for Iraq. Much of Syria's crude oil is heavy and sour, making the processing and refining of Syrian crudes difficult and expensive. Further, as a result of sanctions placed on Syria by the European Union in particular—which accounted for the vast majority of Syrian oil exports previously—there are limited markets available that can import and process the heavier crudes produced in Syria. As such, Syrian government revenues are severely limited by the loss of oil export capabilities, particularly the lost access to European markets, which in 2011 imported USD3.6 billion worth of oil from Syria according to news reports.

In 2011, Syrian total petroleum consumption was 258,000 barrels per day (bbl/d) while total production was 330,800 bbl/d, but the country has limited refining capacity and therefore must import refined products. Sanctions, and the resulting loss of oil export revenues, make importing such products difficult, although several countries continue to pursue energy deals with Syria, including Iraq, Iran, Russia, and Venezuela.

Thailand

Proved recoverable reserves (crude oil and NGLs, million barrels)	453
2011 production (crude oil and NGLs, thousand b/d)	325
R/P ratio (years) (see below)	5.3
Year of first commercial production	1959

Resources of crude oil and condensate are not very large in comparison with many other countries in the region. The data reported by the Thai WEC Member Committee for the present *Survey* show that, after cumulative production to the end of 2008 of 463 million barrels of crude oil, Thailand's remaining proved oil reserves were some 182 million barrels of crude, plus 271 million barrels of condensate. Approximately 70% of the crude reserves and virtually all of the condensate reserves are located in Thailand's offshore waters. Data on reserves of other NGLs were not provided; consequently the calculated reserves/production ratio shown above is based on crude-plus-condensate production of 232 000 b/d in 2008.

Further recoverable amounts (in millions of barrels) reported by the Member Committee consist of 422 probable reserves of crude oil and 337 of condensate, plus 176 possible reserves of crude and 134 of condensate. The total of recoverable reserves of crude oil of some 780 million barrels is closely matched by the corresponding total for condensate (742 million barrels). Total output of oil (crude oil, condensate and other NGLs) has more than doubled since 1999, with an average of 325 000 b/d in 2008. Exports have declined since 2006 to an average of about 40 000 b/d.

According to *Oil & Gas Journal*,Thailand held proven oil reserves of 453 million barrels in January 2013, an increase of 11 million barrels from the prior year. In 2011, Thailand produced an estimated 393,000 barrels per day (bbl/d) of total oil liquids, of which 140,000 bbl/d was crude oil, 84,000 bbl/d was lease condensate, 154,000 bbl/d was natural gas liquids, and the remainder was refinery gains. Thailand consumed an estimated 1 million bbl/d of oil in 2011, leaving total net imports of 627,000 bbl/d, and making the country the second largest net oil importer in Southeast Asia.

Thai oil production has risen in the last few years, although production remains well below consumption levels. About 80 percent of the country's crude oil production comes from offshore fields in the Gulf of Thailand. Chevron is the largest oil producer in Thailand, accounting for nearly 70 percent of the country's crude oil and condensate production in 2011. The largest oilfield is Chevron's Benjamas located in the north Pattani Trough. The field's production peaked in 2006 and declined to less than 30,000 bbl/d in 2010. Chevron is developing satellite fields to sustain production around Benjamas. PTTEP's Sirikit field is another significant crude oil producer supplying 22,000 bbl/d of oil in 2010. Small independent companies, Salamander Energy and Coastal Energy, began exploring onshore and shallow water fields including Bualuang, Songkhla, and Bua Ban that came online in 2009.

Trinidad & Tobago

Proved recoverable reserves (crude oil and NGLs, million barrels)	335
2011 production (crude oil and NGLs, thousand b/d)	149
R/P ratio (years)	11.1
Year of first commercial production	1908

The petroleum industry of Trinidad has passed its centenary, several oil fields that are still in production having been discovered in the first decade of the 20th century. Its remaining recoverable reserves are small in regional terms. Trinidad's probable reserves of oil are 335 million barrels and possible reserves a further 1 561 million barrels, making the republic's 3P oil reserve just over 2.5 billion barrels.

The oil fields that have been discovered are mostly in the southern part of the island or in the corresponding offshore areas (in the Gulf of Paria to the west and off Galeota Point at the southeast tip of the island).

Turkmenistan

Proved recoverable reserves (crude oil and NGLs, million barrels)	600
2011 production (crude oil and NGLs, thousand b/d)	205
R/P ratio (years)	8.0
Year of first commercial production	1911

This republic has been an oil producer for nearly a century, with a cumulative output of more than 5 billion barrels. According to *Oil & Gas Journal*, echoed by OAPEC and BP, its proved reserves are some 600 million barrels. Known hydrocarbon resources are located in two main areas: the South Caspian Basin to the west and the Amu-Darya Basin in the eastern half of the country.

Turkmenistan had proven oil reserves of roughly 600 million barrels in January 2012 based on estimates by *Oil and Gas Journal* (OGJ). Most of the country's oilfields are situated in the South Caspian Basin and the Garashyzlyk onshore area in the west of the country. In addition, Turkmenistan claims its section of the Caspian Sea contains 80.6 billion barrels of oil, though much is unexplored.

Turkmenistan's oil production has increased from 110,000 bbl/d in 1992 to approximately 202,000 barrels per day (bbl/d) in 2010. Production peaked at 213,000 bbl/d in 2004 before declining slightly. Short-term forecasts keep production relatively flat through 2013. About half of production is slated for the domestic market that consumed slightly more than 100,000 bbl/d.

Uganda

The independent oil company Tullow Oil is seeking to develop (in conjunction with two prospective partners) a number of promising oil fields that have been discovered in the vicinity of Lake Albert. Production from the Kasamene field, to serve industrial consumers within Uganda, is expected to commence by the end of 2011. Full exploitation of the deposits might require the construction of an export pipeline to the Indian Ocean coast, although other possibilities are being examined.

United Arab Emirates

Proved recoverable reserves (crude oil and NGLs, million barrels)	97 800
2011 production (crude oil and NGLs, thousand b/d)	2 980
R/P ratio (years)	89.7
Year of first commercial production	1962

The United Arab Emirates comprises Abu Dhabi, Dubai, Sharjah, Ras al-Khaimah, Umm al-Qaiwain, Ajman and Fujairah. Exploration work in the three last-named has not found any evidence of oil deposits on a commercial scale. On the other hand, the four emirates endowed with oil resources have, in aggregate, proved reserves on a massive scale, in the same bracket as those of Iran, Iraq and Kuwait. Abu Dhabi has by far the largest share of UAE reserves and production, followed at some distance by Dubai. The other two oil-producing emirates are relatively minor operators.

A member of the Organization of the Petroleum Exporting Countries (OPEC) since 1967, the UAE is one of the most significant oil producers in the world. According to *Oil & Gas Journal* 2012 estimates, the UAE holds the seventh-largest proved reserves of oil in the world at 97.8 billion barrels, with the majority of reserves located in Abu Dhabi (approximately 94 percent). The other six emirates combined account for just 6 percent of the UAE's crude oil reserves, led by Dubai with approximately 4 billion barrels. Production of these resources is dominated by the state-owned Abu Dhabi National Oil Company (ADNOC) in partnership with a few large international oil companies under long-term concessions. The impending expiration of two existing concession licenses could create opportunities for new entrants into the UAE's energy sector. The ADNOC-led consortia continue to keep the UAE near the top of the list of the world's largest crude oil producers, ranking seventh in 2011 at 2.7 million barrels per day (bbl/d).

With the world's seventh-largest proved reserves of crude oil (97.8 billion barrels), the UAE holds more than 7 percent of the world total. Nevertheless, recent exploration has not yielded any significant discoveries of crude oil. What it lacks in new discoveries, however, it makes up for with an emphasis on EOR techniques designed to extend the lifespan of the Emirates' existing oil fields. By improving the recovery rates at those fields, such techniques helped the UAE to nearly double the proved reserves in Abu Dhabi over the last decade-plus. These gains helped make the UAE the seventh-largest oil producer in the world in 2011, producing 2.7 million bbl/d of crude. Production targets are set by the Organization of the Petroleum Exporting Countries (OPEC), and any increase of UAE's output requires approval from fellow members.

The Zakum system—the third-largest oil system in the Middle East and the fourth-largest in the world—is the center of the UAE's oil industry, accounting for nearly 30 percent of the country's total production in 2010. The Upper Zakum field is run by the ZADCO—which is owned by ADNOC (68 percent share), ExxonMobil (28 percent), and the Japan Oil Development Company (JODCO; 12 percent)—and currently produces 550,000 bbl/d. In July 2012, ZADCO awarded an USD800-million engineering, procurement, and construction contract to Abu Dhabi's National Petroleum Construction Company—along with French firm Technip—with the goal of expanding production to 750,000 bbl/d by 2016. The Lower Zakum field operated by the Abu Dhabi Marine Operating Company (ADMA-OPCO) is also being expanded, with production expected to reach 425,000 bbl/d; up from the 300,000 bbl/d it currently produces.

United Kingdom

Proved recoverable reserves (crude oil and NGLs, million barrels)	2 800
2011 production (crude oil and NGLs, thousand b/d)	1 526
R/P ratio (years)	5.5
Year of first commercial production	1919

Proved recoverable reserves, as reported by the UK WEC Member Committee, are based on a report by the Department of Energy and Climate Change (DECC) entitled *UK Oil and Gas*

According to *Oil & Gas Journal* (OGJ), the UK had 3.1 billion barrels of proven crude oil reserves as of January 2013, the most of any EU member country. In 2012, the UK produced 1.0 million barrels per day of oil (bbl/d) and consumed 1.5 million bbl/d.

The vast majority of UK's reserves are located offshore in the UK continental shelf (UKCS), and most of the oil production occurs in the central and northern sections of the North Sea. Although there is a modest amount of oil produced onshore, in 2012 more than 90 percent of total UK production took place offshore.

In 2012, UK produced approximately 1 million bbl/d of liquid fuels, of which about 881,000 bbl/d was crude oil. The 2012 liquid fuels production level was about 14 percent lower than the 2011 production level, and it reached the lowest production level since the 1970s. EIA's Short-Term Energy Outlook expects UK oil production to continue to decline, remaining below 1 million bbl/d through the end of 2014. The main reason for this decline is the overall maturity of the country's oil fields and diminishing prospects for new substantial discoveries in the future. Although its proximity to major consuming markets makes UK exploration attractive, recent increases in taxes will continue to affect the attractiveness of the UK fields in the longer term.

Despite the large declines in oil production over the last few years, the UK is still one of the largest petroleum producers and exporters in Europe. In 2011, the UK exported approximately 690,000 bbl/d. Export data published by UK's Her Majesty's Revenue and Customs show that the vast majority (82 percent) of crude oil exports were destined to EU countries, mainly Germany and Netherlands.

The United Kingdom is also a significant oil importer, receiving more than 1 million bbl/d in 2011. According to UK's Her Majesty's Revenue and Customs, the majority (67 percent) of the imports came from Norway, a decline from the 72-percent share the previous year. The remainder of UK oil imports came from Russia (8 percent), Nigeria (7 percent), and the Middle East (2 percent).

United States of America

Proved recoverable reserves (crude oil and NGLs, million barrels)	30 900
2011 production (crude oil and NGLs, thousand b/d)	6 734
R/P ratio (years)	11.5
Year of first commercial production	1859

The United States has one of the largest and oldest oil industries in the world. Although its remaining recoverable reserves are dwarfed by some of the Middle East producers, it is the third largest oil producer, after Saudi Arabia and the Russian Federation.

The Energy Information Administration of the US Department of Energy states that proved oil reserves are

Uzbekistan

Proved recoverable reserves (crude oil and NGLs, million barrels)	594
2011 production (crude oil and NGLs, thousand b/d)	111
R/P ratio (years)	14.6
Year of first commercial production	NA

Although an oil producer for more than a century, large-scale developments in the country mostly date from after 1950. The current assessment published by *Oil & Gas Journal* (matched by other publications) shows proved reserves as 594 million barrels, a level unchanged since 1996. Oil fields discovered so far are located in the southwest of the country (Amu-Darya Basin) and in the Tadzhik-Fergana Basin in the east.

Since the late 1990s total oil output has followed a downward trend, falling by 80 000 b/d, or 42%, in the space of ten years. All of Uzbekistan's production of crude and condensate is processed in domestic refineries or used directly as feedstock for petrochemicals.

As mentioned above The *Oil and Gas Journal* (OGJ) estimates that Uzbekistan had 594 million barrels of proven oil reserves in 2012, 171 discovered oil and natural gas fields, 51 of which produce oil and 17 of which produce gas condensates. Uzbekistan's petroleum production consists of roughly 60 percent high-sulfur crude and 40 percent condensates from natural gas fields. Existing oil and gas fields are depleting faster than new discoveries are coming online, spurring the need for further investment.

Because of ageing infrastructure and a dearth of foreign investment and capital, production rapidly declined after 2003. During 2010, Uzbekistan produced 59,000 barrels of oil per day (bbl/d), a 60-percent decline from 2000 levels.

Uzbekistan will remain a net oil importer as long as production declines. Oil demand exceeds supply by nearly two-fold. Domestic oil consumption reached an estimated 139,000 bbl/d in 2010 and has remained relatively constant since the mid-1990s, averaging 150,000 bbl/d. However, the country's goal is to lower oil import dependence and increase exports.

Venezuela

Proved recoverable reserves (crude oil and NGLs, million barrels)	211 000
2011 production (crude oil and NGLs, thousand b/d)	2 566
R/P ratio (years)	>100
Year of first commercial production	1917

Venezuela's oil resource base is truly massive, and proved recoverable reserves are by far the largest of any country in the Western Hemisphere. Starting in 1910, hydrocarbons exploration established the existence of four petroliferous basins: Maracaibo (in and around the lake), Apure to the south of the lake, Falcón to the northeast and Oriental in eastern Venezuela. The country has been a global-scale oil producer and exporter ever since the 1920s, and was a founder member of OPEC in 1960.

According to *Oil and Gas Journal* (OGJ), Venezuela had 211 billion barrels of proven oil reserves in 2011, the second largest in the world. This number constitutes a major upward revision – two years ago the same publication listed the country's reserves at 99.4 billion barrels. The update results from the inclusion of massive reserves of extra-heavy oil in Venezuela's Orinoco belt. Reserves could be even bigger at 316 billion barrels, with further investigation from the "Magna Reserva" project.

In 2010 the country had net oil exports of 1.7 million barrels per day (bbl/d), the eighth-largest in the world and the largest in the Western Hemisphere. While crude oil production for 2011 increased 100,000 bbl/d (and equaled 2009 levels), overall production levels have declined by roughly one-quarter since 2001. Natural decline at older fields, maintenance issues, and the need for increasing foreign investment are behind this trend. In addition, net oil exports have also declined since domestic consumption has increased 39% since 2001.

EIA estimates that the country produced around 2.47 million bbl/d of oil in 2011. Crude oil represented 2.24 million bbl/d of this total, with condensates and natural gas liquids (NGLs) accounting for the remaining production. Estimates of Venezuelan production vary from source to source, partly due to measurement methodology. For instance, some analysts directly count the extra-heavy oil produced in Venezuela's Orinoco Belt as part of Venezuela's crude oil production. Others (including EIA) count it as upgraded syncrude, whose volume is about 10 percent lower than that of the original extra-heavy feedstock.

Vietnam

Proved recoverable reserves (crude oil and NGLs, million barrels)	4 400
2011 production (crude oil and NGLs, thousand b/d)	317
R/P ratio (years)	40.5
Year of first commercial production	1986

During the first half of the 1980s oil was discovered offshore in three fields (Bach Ho, Rong and Dai Hung), and further discoveries have since been made.

Published estimates of Vietnam's oil reserves vary widely. *Oil & Gas Journal* assumes entirely different figures compared to other assessments, quoting only 600 million barrels, which implies the very low R/P ratio of 5.5.

Production of crude oil began in 1986 and rose steadily until 2004, but subsequently has fallen to only about 300 000 b/d, all of which is presently exported. Output of NGLs is of minor proportions, at around 15 000 b/d.

According to *Oil & Gas Journal* (OGJ), Vietnam now ranks third in terms of proven oil reserves for the Asia-Pacific region. Vietnam held 4.4 billion barrels of proven oil reserves as of January 2012, which was significantly higher than 0.6 billion barrels of oil in 2011. This increase is in part a result of Vietnam's efforts to intensify exploration and development of its offshore fields. Ongoing exploration activities could increase this figure in the future, as Vietnam's waters remain relatively underexplored.

Vietnam's oil production increased steadily until 2004, when it peaked above 400,000 barrels per day (bbl/d). Since 2004, oil production has slowly declined, reaching an estimated 326,000 bbl/d in 2011. EIA forecasts that the country's oil production will rise by around 50,000 bbl/d within the next 2 years, based on several smaller fields anticipated to come online by 2015. These fields should offset declining production from mature basins, but Vietnam must accelerate exploration efforts to maintain current production levels in the longer term. A fraction of Vietnam's oil production, almost 20 bbl/d in 2011, is in the form of natural gas liquids (NGLs).

In 2010, Vietnam consumed 320,000 bbl/d of oil, and EIA estimates demand to increase to more than 400,000 bbl/d in 2013, reflecting the economic growth and industrial developments within Southeast Asia. EIA estimates consumption surpassed production in 2011.

One of the most active areas for ongoing exploration and production activities in Vietnam is the offshore Cuu Long Basin. Vietnam's oil production has decreased over the last seven years primarily as a result of declining output at the Bach Ho (White Tiger) field, which accounts for about half of the country's crude oil production. After reaching peak output of 263,000 bbl/d in 2003, the field's production dropped to an average 92,000 bbl/d in early 2011. It is expected that Bach Ho's production decline rate will range from 20,000 bbl/d to

25,000 bbl/d through 2014. Vietsovpetro intends to boost oil production by using water injection to stem declines of aging fields and by investing USD7 billion on exploration activities over the next five years.

Vietnam is currently a net exporter of crude oil but remains a net importer of oil products. According to EIA, oil demand has nearly doubled in the past decade from 175,000 bbl/d in 2000 to an estimated 320,000 bbl/d in 2010. Vietnam still needs to import about 70 percent of refined products and petrochemicals since the output from the Dung Quat refinery does not satisfy domestic demand. As more refineries are scheduled to come online, PetroVietnam anticipates meeting 50 to 60 percent of the domestic product demand by 2015. FACTS Global Energy forecasts that domestic petroleum product demand will more than double by 2030 to nearly over 830,000 bbl/d from around 375,000 bbl/d in 2011. The transportation sector, which uses gasoline, diesel, jet fuel, and fuel oil for rail, drives about 60 percent of petroleum product demand. The remaining oil product demand originates from liquefied petroleum gas (LPG) use in the residential sector and small amounts of products used in the industrial and power sectors.

Yemen

Proved recoverable reserves (crude oil and NGLs, million barrels)	3 000
2011 production (crude oil and NGLs, thousand b/d)	317
R/P ratio (years)	23.0
Year of first commercial production	1986

After many years of fruitless searching, exploration in the 1980s and 1990s brought a degree of success, with the discovery of a number of fields in the Marib area, many yielding very light crudes. Oil discoveries have been made in two other areas of the country (Shabwa and Masila) and Yemen has evolved into a fairly substantial producer and exporter of crude.Oil production peaked in 2002 and has since followed a consistently downward path. Total output in 2008 was 317 000 b/d (including 24 000 b/d of gas-plant LPG). About 70% of Yemen's crude production is exported, largely to Singapore, Japan, Korea Republic and other Asia/Pacific destinations

According to the *Oil & Gas Journal*, Yemen had proven crude oil reserves of 3 billion barrels as of January 1, 2012. Yemen's oil reserves and production are located in five main geographical areas: Jannah and Iyad in central Yemen, Marib and Jawf in the north, and Shabwa and Masila in the south. All production comes from two sedimentary basins, Marib-Shabwa and Sayun-Masila, out of a total of 12 basins believed to hold reserves. Yemen's oil reserves are generally light and sweet (low in sulfur content) at API gravities ranging from 28 degrees to 48 degrees, with the highest quality crude coming from the Marib-Jawf fields.

In 2011, Yemen's total oil production averaged about 170,000 barrels per day (bbl/d), down from 259,000 bbl/d estimated for 2010. Production has been declining steadily since reaching a peak of 440,000 bbl/d in 2001 due to a lack of sufficient new investment in exploration and inadequate maintenance of facilities.

Yemen had total oil exports of 103,000 bbl/d and total domestic consumption of 157,000 bbl/d in 2010, according to EIA estimates. Asian markets account for the majority of Yemen's oil exports. With growing domestic consumption and decreasing production, net exports are on a declining trend. Yemen imports some refined products; in 2008, the most recent data available, gross imports of refined products were estimated at 62,000 bbl/d, mainly distillate and residual oils, while 18,000 bbl/d of products were exported.

Unconventional oil

Shale Oil

Introduction

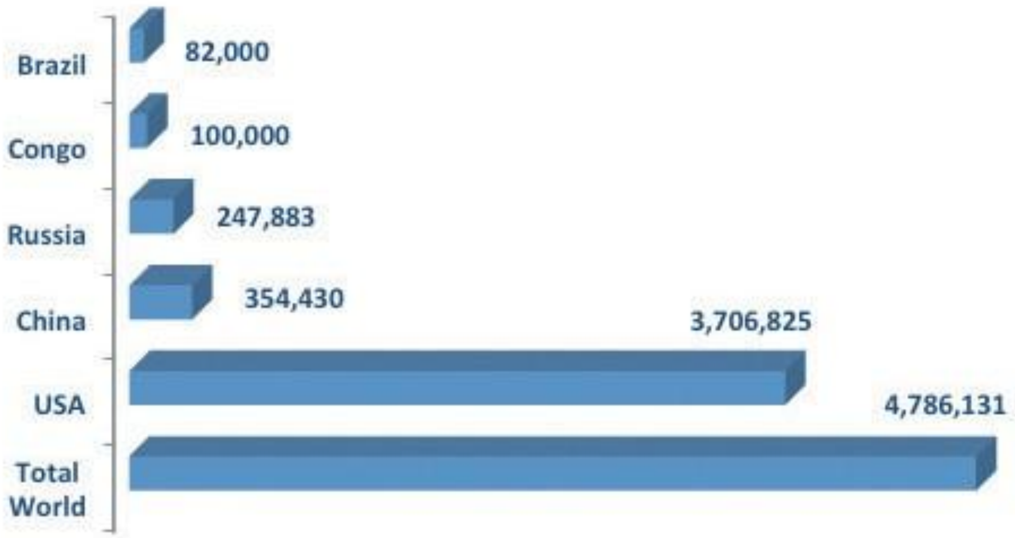
This section on oil shale is based on the findings of the 2013 report.

While the overall global demand for oil is growing, the reserves to production ratio for oil has remained at the same level of approx. 40 years for the past three decades thanks to continued new discoveries and more efficient technologies which allow higher oil recovery rates. Moreover, huge resources of unconventional oil will ensure the availability of oil for decades to come.

In the changing global oil landscape, the United States is emerging as an oil superpower. In addition to being the highest oil consuming nation, USA is the world's second largest crude oil producer after Saudi Arabia, and its oil shale endowment accounts for about 75% of the world total.

The recent success of shale gas in the United States can be considered a good example of how advances in technologies can turn the market upside down transforming North America from the largest gas importing region into a potential net exporter of gas.

Figure 1
Oil Shale resources (million barrels): Top 5 countries in 2011.
Source: WEC World Energy Resources, 2013



Definition and current applications

What is oil shale? Oil shales are fine-grained sedimentary rocks containing relatively large quantities of organic matter (known as 'kerogen') from which significant volumes of shale oil and combustible gas can be produced. The use of oil shale can be traced back to ancient times. Common products made from oil shale were kerosene/lamp oil, paraffin wax, fuel oil, lubricating oil and grease, naphtha, illuminating gas, and the fertiliser chemical, ammonium sulphate. As the number of automobiles and trucks was increasing rapidly in the early 1900s, the feared shortage of motor fuels was looming in peoples' minds. This led to the search of substitutes for petrol and made use of oil shale in transport.

Oil shale can be used in various ways from electricity generation via direct combustion to production of a wide range of petrochemical goods, including shale oil and other liquid fuels. Shale oil can be used as a direct substitute for conventional crude oil, and therefore it seems likely that in the coming years the fast growing demand and potentially higher prices for conventional oil will result in a rise in the demand for shale oil. Some forecasts indicate that oil shale can account for more than a third of the growth in use of unconventional oil by 2030.

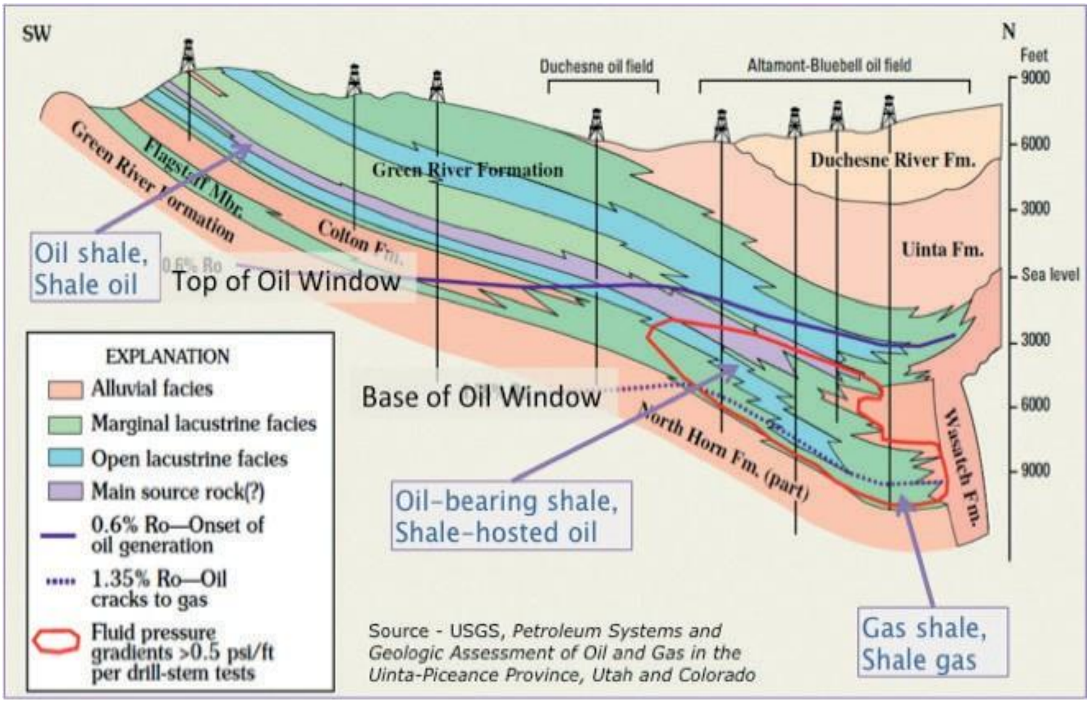
Conceptual Oil Shale Development Issues

According to the WEC's World Energy Resources survey, proven oil reserves have increased during 1987-2007 by 17% and proven gas reserves by 38%.

Figure 2 shows a schematic cross-section through the Uinta Basin of Utah, which serves to illustrate a terminological issue that has dogged discussion of shale-hosted hydrocarbon resources for some years now. It shows approximate depths for both the oil and gas windows and highlights a section of the Green River Formation that consists of oil shale at

Figure 2

Schematic cross-section showing the relationship of oil shale, oil-bearing shale and gas shale and the related hydrocarbon resources derived from them



shallow depth, but is responsible for half of Utah's oil production where it lies in the oil window. Deeper still, it might be considered a gas shale.

One of the first things most people hear about oil shale is that it is a misnomer because there is not oil in the rock. This is the equivalent of saying it is wrong to call Cabernet Sauvignon a wine grape because there is no wine in it.

The terms oil shale (for the rock) and shale oil (for the retorted product) have been well-understood for more than one hundred years now. These two terms have been consistently applied to the fine-grained organic-rich rock that only yields its petroleum product on heating either at the surface or at depth.

The development of shale gas from gas shale formations (like the Barnett and Marcellus formations) created another pair of terms for a different unconventional resource and its host rock. But when the liquid rich part of these formations (and other formations containing mainly liquids) began to be developed, even technical people ignored the technical priority of shale oil as the product of retorting oil shale.

Massive confusion about the size and impact of these different but distinctly related resources arose. Oil-bearing shale and shale-hosted oil have been suggested as alternative terms for the rock formation and the product for the Bakken and Eagle Ford and their relatives. Others in industry are now calling this group of products and plays "Tight Oil," in part because the oil commonly resides in silty or chalky units interbedded with or adjacent to the organic rich source shale, but that would not generally be called shale.

But this approach leaves a gap with respect to the rock term. You could say "tight-rock oil," but this still has no good generic equivalent for the rock formations (like oil shale and gas shale) that explorationists will be looking for.

Oil shale development in specific economic niches

As the capital requirements for oil shale development projects are very high, and the infrastructure and facilities involved very complex, it is likely that oil shale development will not advance until economics or security demands require it.

Estonia – Longstanding production, engineering know-how, and lack of other resources have driven Estonia to develop both power and oil production from oil shale. Today, companies also have begun active export marketing campaigns targeted at USA, Jordan, Morocco and the Ukraine.

Brazil – Petrobras has investigated the potential for development using its own technology in Jordan, the U. S. and Morocco. Although they are currently far more directed at large offshore oil and gas developments, another company, using a modified version of the PetrosixTM retort, is proposing to produce shale oil for a niche market within Brazil, and investigating the application of the new system to other countries. Initial development started when traditional reserves were sparse, and accompanied aggressive development of biofuel capability.

China – Currently the largest producer of oil from oil shale, China has been building retorts at a remarkable pace. The resource is very large, and research is being directed at both surface and in situ retorts.

Oil shale is unlikely to meet the skyrocketing demand for energy of this developing country, but it will continue to be a contributor.

Australia – Production of shale oil is only in demonstration mode at present. The discovery of large gas reserves have overshadowed the technical progress of shale oil due to the indication that these reserves may include significant shale-hosted oil plays. Nevertheless, it appears that the tide may have turned with the lifting of a moratorium on shale oil production, and development is proceeding.

Active Developers

Israel – Israel Energy Initiatives is bringing in situ technology to bear on the only significant onshore resource for oil production. They are also actively exporting technology through parent Genie Oil in,for example, a recent agreement with the Mongolian government.

Jordan – Like Israel, endowed with few traditional resources, and impacted economically by large bills for imported fuel, and also by subsidies of a low-income population, Jordan has worked hard and made agreements with a diverse group of companies to develop both oil and power production, employing both surface and in situ methods. If successful, these projects will make Jordan an important producer.

Mongolia – Recent agreement with Genie Oil, and the presence of Total and at least two other companies interested in oil shale, Mongolia is showing itself eager to develop an indigenous energy source.

Morocco – With the active participation of the government's Organization National des Hydrocarbures et des Mines, Morocco is working with several companies to develop oil shale to move away from total dependence on other Arab countries' oil and gas.

Oil shale resource assessment

Although information about many oil shale deposits around the world is rudimentary at best, the potential resources of oil shale are enormous. The absence of statistics and formal assessments however makes it difficult to produce reliable estimates, and these estimates can change significantly after discoveries of new deposits. Total world resources of shale oil currently are conservatively estimated at 4.8 trillion barrels. This is almost 4 times more than the crude oil resources which stand at 1.3 trillion barrels. However, economically recoverable oil shale reserves are much lower.

Oil shale resources are widely distributed around the world. Some 40 countries have registered about 300 deposits, with the USA accounting for approx. 77% of world resources. In the Middle East, only Jordan and Israel are reporting oil shale data, with Jordan estimating its reserves at 28 billion and Israel at 79 billion barrels. In Jordan, deposits are distributed over 26 sites and located near the surface, thus reducing exploitation costs.

China undertook its first national oil shale evaluation in 2004-2006. It confirmed that there is a vast and widespread resource across 47 basins and 80 deposits with the total estimated in-place shale oil resource of 354 billion barrels. Nearly 70% of the deposits are located in Eastern and Middle China. Current shale oil production is in North-East China

Russia has the third largest oil shale resources in the world after USA and Brasil. The total resource of oil shale is estimated at 43,41 bln t. The oil shale deposits in Russia are located in the Baltic basin, in the East of the European part of the country – and in the North-Eastern part of Siberia. There are more than 80 oil shale deposits identified in Russia.

Sizeable deposits of oil shale have been discovered in various parts of Israel and current estimates of the theoretical reserves total some 12 billion tonnes.

However, a recently released fact sheet by the US Geological Survey highlights the fact that much of this amount is contained in rock of such low grade that it is likely to be a long time before it is utilized (See Figure 3). About 1.2 trillion barrels of the resource is contained in rocks that would be considered better than marginal (≥15 gal/tonne), the main part of it in the Piceance Creek Basin of Colorado and about 400 billion barrels of the resource are contained in rocks considered high grade (≥25 gal/ton). Assessments of oil shale deposits require more detail than assessment of any other global resource because of the variety of shales.

This requirement most certainly holds back many other countries with potential deposits of oil shale,

This requirement most certainly holds back many other countries with potential deposits of oil shaledue to the high costs of assessments and also lack of domestic expertise in this area.

Changes in the growth trajectory of shale-hosted oil production

The two most prominent oil-bearing shale plays in the United States at present are the Bakken and the Eagle Ford. Daily production rates for these two fields are shown in Figure 3a. Plotted on the semi-logarithmic grid where a straight line indicates exponential growth, it is obvious that the North Dakota Bakken shows three curves, each starting with a minor drop in the production rate.

During the first period of 2.25 years of the recent economic boom, production rose by about 6% per month. In response to steadily rising oil prices, it then accelerated to nearly 11% per month. However, after a drastic price drop in late 2008, the production growth rate dropped back to about 4% per month, despite a fairly rapid recovery of oil price. The break in slope occurred at about 100,000 barrels per day as at that stage the pressure reached the point where further growth would require additional production capacity.

This appears to have been driven by the strong capital constraints at the time, and possibly by at least some companies reaching a point where most land was held by production

Figure 3a shows daily oil production from the Bakken Formation in North Dakota and the Eagle Ford Formation in Texas.

Figure 3b shows that, during this time, production increases appear to have undergone three upward spikes followed by extended, erratic decline, ending with negative growth values.

Figure 3c shows a similar declining trend for the monthly growth rate for the Eagle Ford over much of the life of this boom. It is worth noting that the gas production from the Eagle Ford has declined by a third over the last year (driven, presumably by price drops). In both cases, if the long term pattern remains above 1% per month (>12% per year) it will still be impressive growth. Most important, is that the exploitation of these shales has produced a massive impact on the global market by increasing the diversity of supply and economic options for many importing nations.

The two most prominent oil-bearing shale plays in the United States at present are the Bakken and the Eagle Ford. An interesting development can be noted: while tracking the production growth of these two plays over the past year. Daily production rate for these two fields is shown on Figure 3a.

Figure 3

Distribution of the US oil shale resource (Total Resource: 4291 billion barrels)

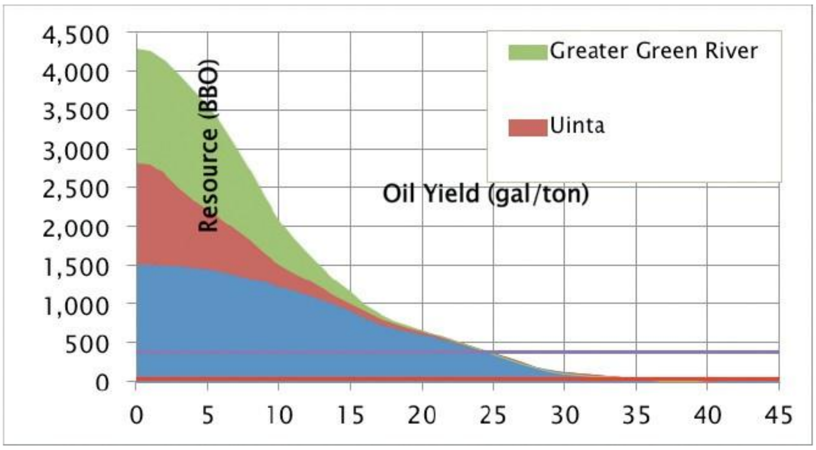


Figure 3a

Daily oil production from the Bakken Formation in North Dakota and the Eagle Ford Formation in Texas. Average monthly production increase for the Bakken are shown in the legend in parentheses

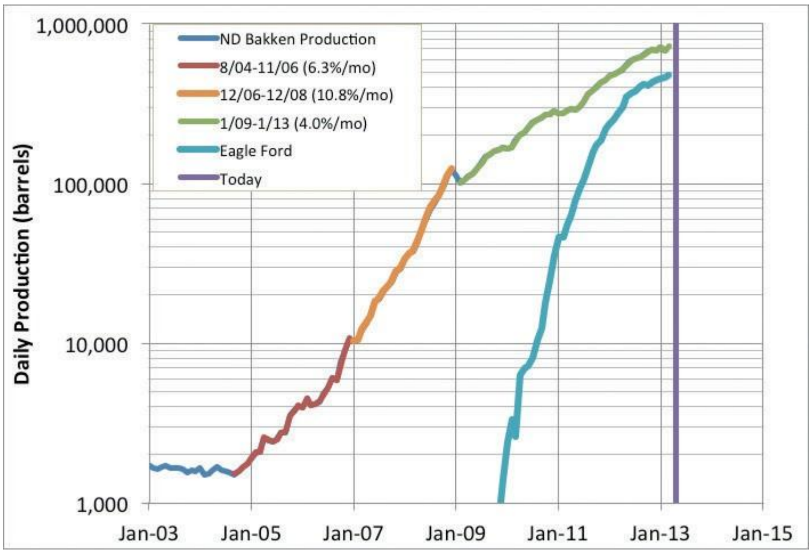


Figure 3b

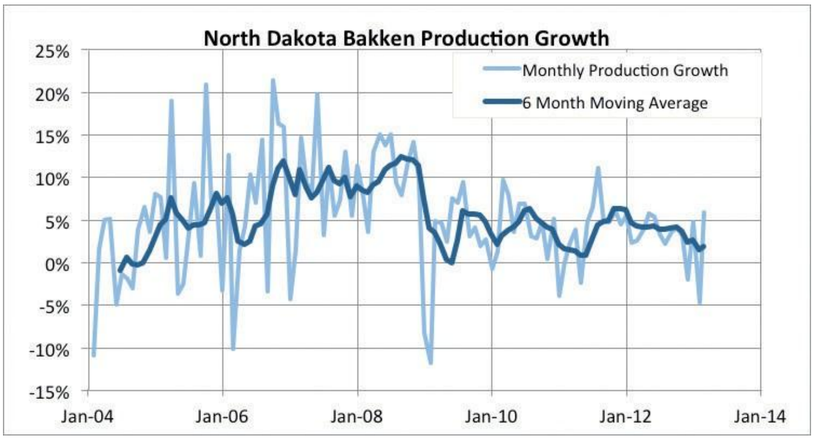
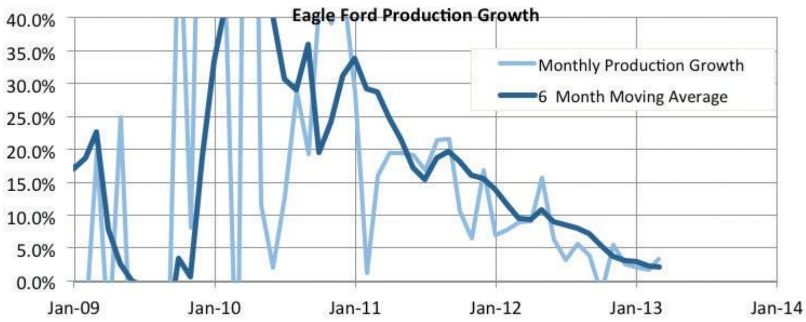


Figure 3c



Plotted on the semi-logarithmic background, where a straight line indicates exponential growth, it is clear that the North Dakota Bakken shows three phases, each starting with a small drop in production rate.

For the first 2¼ years of the high demand during the boom, production rose by about 6% per month. In response to steadily rising oil prices, it then accelerated to nearly 11% per month.

Then, after the drastic price drop in late 2008, the growth rate dropped back to about 4% per month, despite the fairly rapid recovery of oil price. The break in slope occurred at about 100,000 barrels per day, at a time when producers appear to have only just begun to evaluate infrastructure limitations to increasing production.

Overview of Technologies

The shale oil can be extracted by surface and in situ of retorting and depending upon the methods of mining and processing used. As much as one-third or more of this resource might be recoverable.

The amount of oil shale can be economically recovered from a given deposit depends upon many factors, including geothermal heating, mine depth, surface land uses and transport of the oil to the market. There are several technologies which make it possible to produce shale oil within the given economic boundaries and at current market conditions.

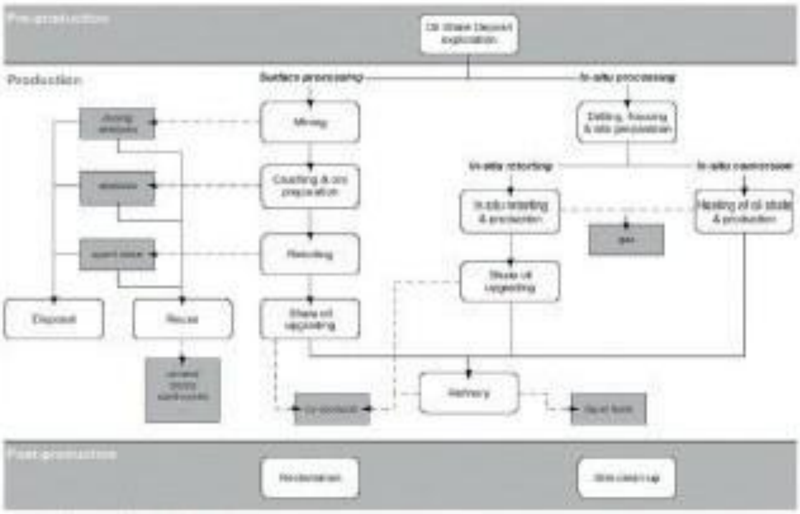
Other applications involve direct firing in special boilers to produce electricity. For example, Estonian companies in Jordan are negotiating purchasing contracts for such boilers, but the relatively high price of electricity production by such installations appears to be an issue. However, there are many other technologies under development (in situ, etc.). Economies of scale are needed to lower unit production costs of these technologies and units would have to become bigger.

Above Ground Extraction

Above ground extraction is the oldest technique of getting the oil shale out of the ground and can be further divided into categories depending on the way heat is applied.

- **Direct Heating**: Air is mixed with the hot shale resulting in combustion. The resultant gases heat the new shale which is being pushed into the retort. The fuel comes out as oil and gas with a very low calorific value British Thermal Unit (BTU).

Figure 4
Technological overview



- **Hot Solids Mixing**: This method involves mixing preheated solids with fresh shale. The heat needed to heat up the solids is generated outside the retort vessel. Because there is no combustion inside the retort, the resulting gas has a very high BTU.

In-situ Retorting (Underground Extraction)
This process involves heating the oil shale underground to extract the oil and other elements. The heating caused by combustion of shale with air leads to the thermal decomposition of Kerogen. The oil is then forced to flow to the production well. In-situ extraction methods can also be classified into different heating methods.

- True In-situ is a method by which the oil and all the other components of oil shale are extracted underground using wells. As soon as the formation is fractured, superheated steam is injected into the formation raising its temperature considerably. When the temperature is high enough for pyrolysis, air is injected into the formation. When the oil shale ignites, the injection well is sealed to increase the pressure in the rock formation.
- Modified In-situ is a relatively new concept to extract oil shale out of the ground. It involves creating an underground fixed-bed retort by blasting and mining. The table below shows the different In-situ methods developed by various companies and advantages and disadvantages of using
- The limited competitiveness of oil shale during the last decades has already forced industry to reduce its cost through improved or innovative technologies and management practices: selective mining and backfilling, in-situ processing, near-zero CO_2 emissions surface retorting and other methods.

At the present time the generators are still the main devices for thermal processing of oil shale in category 25-125 mm. The largest production unit running the process has the capacity of 1000 tonnes of shale per day. It was taken into service in 1980, in Kohtla-Yarve.

The most prospective and high-production in Estonia remain to be the plants with solid heat carrier and capacity on shale 3000 tonnes per day (UTT-3000) which run on «Galoter» (see box with Case Study). Two such plants are operating at Estonian electric power station in city Narva (one of them since 1980, the second one - since 1984).

There is a number of other technologies developed by different companies.

- “Petrosix” developed by the National Brazilian Corporation “Petrobras”. This process is used for processing the oil shale from deposit Irati (Brazil). The fractional composition of feed shale is from ¼ to 2¾ inches (6.25-69.0 mm);
- “Lurgi-Ruhrgas” for pyrolysis of oil shale with sizes up to ¼ inch (6.25 mm).
- Retorts of Fushun type for processing the oil shale in China. The fractional composition of oil shale at the entrance in retort constitutes from 8 to 75 mm.
- “Aostra-Tasiyuk” (ATP) developed in Canada by Wiliam Tasiyuk (the company UMATAK Industrial Processes), couldn’t be implemented both in Australia and China.
- Chevron is developing an in-situ technology which will be economically sustainable and environmentally responsible.

Production

Currently the oil shale industry is concentrated in a few countries, including Brazil, China, Estonia, Germany, Israel, Russia and the United Kingdom. These countries together used to produce over 30 million tonnes of shale oil per year between 1963 and 1992. From the peak in 1981, the annual production dropped to about 15 million tonnes.

Each country has a specific reason to continue their oil shale activities. In Russia, for example, more than a thousand scientists continue their work on oil shale despite unclear and often negative market signals. However, the strong believe in the future of oil shale helps to retain specialists and recruit followers. There oil shale can be considered a legacy which they want to carry into the future.

Economics

Petroleum-based crude oil is cheaper to produce today than shale oil for several reasons, including the additional costs of mining and extracting. Only a few deposits are currently being exploited: in Brazil, China, Estonia, Germany and Israel.

Production costs of oil from oil shale rock are dependent upon a number of input factors: technology used, properties of oil shale, location of the resource, regulatory and fiscal regimes and final products. On average, the production cost is estimated at between 70 and USUSD100 per barrel. At current crude oil prices (around USUSD95 a barrel sustained price) shale oil can compete with conventional oil.

Country	Proven Resources in Million Barrells
Australia	32,000
Brazil	82,000
China	10,000
Confo (Republic of)	100,000
Estonia	16,000
Italy	73,000
Jordan	34,000
Morocco	53,000
Russian Fedration	248,000
United States of America	4,285,000
Total	**4,933,000**

Environmental considerations

As most industrial processes, production of shale oil faces a number of environmental challenges. In-situ technologies can be harmful to groundwater and other oil shale processing technologies require large amounts of water.

The environmental impacts of above ground retorting are much more technology-specific. For example, technologies using gaseous heat carriers have a problem with solid waste containing organic residue.

Most solid heat carrier technologies struggle with high CO_2 emissions.

Generally, new generation technologies such as fluidized bed combustion, could reduce CO_2 emissions from oil shale-based power plants. Expectations in the 1970's, that the vast resources of oil shale could raise world oil shale production to 150 to 200Mt by 2000, have not materialised. New oil shale processing technologies should be technically feasible, environmentally acceptable and economically viable. Today this still seems to be the main challenge for shale oil's success.

Hydrofracking is used not only to produce gas, but also oil which is actually more profitable. It is expected that US shale oil production will reach 1.4 million barrel/day by 2020. Public concerns include land use, ground water pollution and CO_2 emissions. In the densely populated Europe, these concerns weigh heavily: France and Bulgaria for example outlawed fracking. Resistance grows also in Germany, Romania and Czech Republic. The shale boom is still early in its life span, consequently our understanding of the environmental impact of fracking will become more clear in time.

The economic consequences vary from one country to another. The fracking boom in the US caused oil prices in the US and European markets to drift apart. West Texas Intermediate crude became 13USD/bbl cheaper than Brent. The US shale gas boom depressed natural gas prices by 80 %; now gas in the US costs half of that in Germany.

Generally, the US has witnessed the greatest changes in the gas industry. Amongst these changes are:

- Revival of American manufacturing
- Availability of an extensive pipelines network to transport the product to the market
- Overproduction and benefits to the US consumers

Investors in the US have so far been attracted by the profitability of companies active in the exploitation of shale and sand, and related equipment, either in investing directly in the companies concerned or, indirectly, in energy funds.

However, profitability could become a concern, as a continued decline of shale gas/oil prices would be self-defeating. Due to the lack of exploration, profitability in Europe has not yet been ascertained and would be in any case below US returns.

The main constraint to further expansion of oil shale business will continue to be public concern.

Risks and Rewards in the oil shale business

No investment is risk free. Neither is an investment in oil shale. The highest risks to the developer is the down side price volatility of crude oil. Lest we not forget, oil prices in July of

Technology Case Study - Galoter oil shale technology

Galoter is one of the most efficient technologies in the world for oil shale processing by pyrolysis using the solid heat carrier. The name Galoter is an abbreviation consisting of parts Gal and ter. Gal comes from the name of the technology inventor Galynker Israel Solomonovich – the researcher at the Krzhizhanovsky Power Engineering Institute and ter which refers to the thermal nature of the process. Galynker received the patent with a priority of invention on 29 December 1945. Step by step – at the laboratory of the Institute and at the pilot industrial-scale plants with capacity of 2 / 200 / 500 and 3000 t/day under scientific leadership of ENIN in Estonia, the researchers worked on the development of oil shale thermal processing to solve technical problems and improve the technological process and the equipment. In 1989 the upgraded production units UTT-3000 were put into operation, and they remain until now the largest and most efficient units in the world.

The main competitive advantages of Galoter technology are:

- Thermal processing of oil shale with particle size from 0 to 25 mm;
- Products of the process are the highly calorific shale oil (38-40 MJ/kg) and gas (35-37 MJ/nm3);
- Ash obtained in the oil shale processing under low-temperature combustion of shale semi-coke is used as the solid heat carrier;
- A part of ash not used in the process can be used in construction industry, agriculture and other applications without any environmental limitations;
- The excess heat from combustion products after the technology furnace is used for generation of electricity to run auxiliaries.

New experiments and investigations are currently conducted by ENIN using the modern experimental base. It is estimated that new plants will increase the output of liquid fractions by 150-200% with the same unit capacity unit.

2008 were USD148/bbl; 5 months later, the oil price reached USD30/bbl. Such price volatility impacts investor confidence for years and hinders the formation of the types of capital required to exploit oil shale.

It takes many years for a particular oil shale project to yield financial returns. This problem can be resolved by using financial derivatives such as a forwards contract. The company that extracts the oil from particular oil shale deposit can negotiate a contract with interested refineries that want to purchase that oil in the future and set a specific date and price for delivery (for example USD80/bbl on 13th March 2017).

This way refineries will be obliged to buy oil for that price no matter what the market conditions are. It could very well prove to be a very profitable venture for the purchasing party if the price of crude oil stays above USUSD95/bbl.

Long term derivatives are not very common in the financial industry and if the refineries lack the tools to perform sufficient risk analysis on future and long term price of oil, then this method can only exist in theory.

Regulatory risk

The operating cost of producing oil from oil shale (from a particular deposit) currently does not take into account the carbon or emission tax. It is estimated that the process of extraction oil from oil shale and turning it into feedstock for the refineries, generates 25-75% more emissions than conventional oil, therefore it is reasonably to assume that if an emissions tax was introduced in the US for oil shale then it would one of the biggest factors in the operating costs.

Technological Risk
Since the discovery of oil shale, many companies have spent billions of dollars on research and development to explore different extraction technologies.

Finally, the market players will assess the relevance of different technologies and approaches. They and only they themselves will decide upon their individual needs (imports/ exports into/from different countries, marketing purposes, costs etc.).

It is key to remember that costs are the main driver for all economic activities which will include now more and more corporate and social responsibility (CSR), and sustainability aspects. In a cost and CSR-driven economy, the role for voluntary higher standards will remain clearly mitigated

Emerging messages

The world´s transport system is based on one single fuel - oil and today there does not seem to be any realistic alternative to oil. Demand for oil is expected to grow for decades to come, along with the overall demand for energy. Oil shale can help meet this demand and should be regarded as an integral part of the energy mix.

To achieve scaling-up in oil shale production, policies that are consistent, long-term and supported by broad stakeholder participation are needed. They should also fit in the context of larger transportation goals

Supportive government policies have been essential to the development of oil shale over the past decades. Blending regulations, tax incentives, government purchasing policies, and support for infrastructure and technologies have been the most successful in increasing shale oil production. Countries seeking to develop domestic fuel industries will be able to draw important lessons—both positive and negative—from the industry leaders, in particular Russia, Estonia, Jordan, Israel, China, Brazil, the United States, and the European Union.

Oil shale can help diversify supply of fuels, enhance security of supply and mitigate economic volatility related to crude oil price fluctuations.

Support the investment flowing into oil shale business through full transparency of public sector requirements and actions.

Conclusions

Oil shale policies should focus on market development and facilitate sustainable international trade in oil shale and related products. The geographical disparity in production potential and demand pose barriers to trade in oil shale. Free movement of oil-based products around the world should be coupled with social and environmental standards and a credible system to certify the compliance.

Consumer demand is a powerful driver of the market. Therefore, consumer awareness and availability of relevant information have become powerful factors in decision making. Strategies to increase the public's awareness about oil shale should include various forms of public education, such as formal awareness campaigns, public announcements, university research, etc.

When performing analysis of fuel source and type, an LCA is necessary for understanding of economic, energy and environmental impacts using a common, objective and transparent methodology.