Unconventional fossil hydrocarbons fall into two categories: resource plays and conversion-sourced hydrocarbons. Resource plays involve the production of accumulations of solid, liquid or gaseous hydrocarbons that have been generated over geological time from organic matter in source rocks. The character of these hydrocarbons may have been modified subsequently, especially in the case of solids and extra-heavy liquids. These unconventional hydrocarbons therefore comprise accumulations of hydrocarbons that are trapped in an unconventional manner and/or whose economic exploitation requires complex and technically advanced production methods. This review focuses primarily on unconventional liquid hydrocarbons. The future potential of unconventional gas, especially shale gas, is also discussed, as it is revolutionizing the energy outlook in North America and elsewhere.

1. Introduction

Unconventional fossil hydrocarbons fall into two categories: resource plays and conversion-sourced hydrocarbons. Resource plays involve the production of accumulations of solid, liquid or gaseous hydrocarbons that have been generated over geological time from organic matter in source rocks:

- solid bitumen;
- liquid extra-heavy oil;
- tight oil;
- gaseous tight gas sandstone/limestone; coal seam gas; shale gas; gas hydrates.

The character of these hydrocarbons may have been modified subsequently, particularly in the case of solids and extra-heavy liquids.

These unconventional hydrocarbons therefore comprise accumulations of hydrocarbons that are trapped in an unconventional manner and/or whose economic exploitation requires complex and technically advanced production methods.

...
exploitation requires complex and technically advanced production methods. Although this review focuses primarily on unconventional liquid hydrocarbons, the future potential of unconventional gas, especially shale gas, is also discussed, as it is revolutionizing the energy outlook in North America and elsewhere.

The second category of unconventional hydrocarbons, which is not considered here, but is dealt with elsewhere in this Theme Issue, comprises gas and liquids manufactured from coal-, gas- or organic-rich shales and non-geological biofuels [1,2].

Predicting the future in the petroleum exploration and production (E&P) industry is not easy. Experts have had their fingers burned attempting to estimate what the price of oil will be in only a few months’ time. There have been many estimates of when the peak of global oil production will occur, and that point still appears to be some way down the road. Less than a decade ago, there were proposals to build as many as 30 liquefied natural gas (LNG) import terminals in the USA to meet projected demand for gas. Today, such is the glut of domestic gas production, there are more plans to build LNG export terminals than import terminals [3], and the USA is forecast to become a net exporter of LNG in 2016 [4].

In predicting future trends, it can be instructive to examine what has happened in the past. Extrapolating from events and trends in one country is fraught with risk. No two countries are alike. Even if subsurface geology may be similar, conditions above ground (mineral rights ownership; legal and fiscal terms; infrastructure; physiographic terrain) may be extremely different. However, the USA is sufficiently highly explored to indicate the possible results when both subsurface and above-ground conditions are highly favourable, and its history is instructive.

The world’s first gas well (1825) and oil well (1859) were drilled in the USA. During its 188-year exploration history, some three million wells are believed to have been drilled, at least twice as many as in the rest of the world combined. Over 205 billion barrels (Gb) of oil have been produced, more than in Russia (150 Gb to date) or in Saudi Arabia (125 Gb).

There are two periods (1980–1985; 2003–2012) when the decline rate in US onshore production decreased and production ultimately increased (figure 1). Both of these can be attributed to substantial increases in US domestic oil prices that followed global events (1979, Iranian revolution; 2003, invasion of Iraq and rapid increase in Chinese consumption). The final observable event from 2008 onwards is the significant production of unconventional tight oil,
Figure 2. US natural gas production, 1900–2012. Data source: US Energy Information Administration statistics. (Online version in colour.)

Initially from the Bakken Formation and more recently from the Barnett Shale and Eagle Ford Formation, and certain other formations.

Outside the onshore fields of the lower 48 states, one feature links the other four sources of additional production (the continental shelf; Alaska north of the Arctic Circle; deep water in the Gulf of Mexico; production from impermeable (‘tight’) source rocks). Their production required major advances in technology.

Turning to US production of natural gas (figure 2), it can be seen that until the mid-1980s, especially onshore, production followed the sort of near-symmetrical curve with a single principal maximum forecast by Hubbert [5,6]. The peak of onshore production occurred in 1970 and for the USA as a whole in 1973. But from 1987 production started to rise again, driven by increases in onshore production. In 2010, onshore natural gas production exceeded the 1970 peak, and 2011/2012 saw new peaks for total US gas production, exceeding that of 1973.

By looking in more detail at the period 1990–2011 (the period for which appropriate data are available), this major reversal can be attributed unequivocally to three types of unconventional gas production: shale gas, coal seam gas and tight gas (figure 3).

In 2008, unconventional natural gas accounted for over half of US gas production, driven by an increase in shale gas production. Three years later, the ongoing increase in shale gas production resulted in over 68% of all natural gas production coming from unconventional sources.

Evidently, therefore, both unconventional oil and unconventional gas sources have had a major impact upon recent US petroleum production. This success provides a context within which to discuss unconventional petroleum resource potential worldwide.

(a) Terms

Within this review, the following terms are used.

— Energy return on investment (EROI): the ratio of energy returned from an energy-gathering activity to the energy expended in that activity.
— Kerogen: fossilized organic material within a sedimentary rock.
— Oil-prone: (a rock) containing kerogen of sufficient quality and quantity to yield oil when thermally matured.
2. Unconventional hydrocarbons

There is no formal or generally accepted definition of unconventional hydrocarbons. The very use of the term ‘unconventional hydrocarbons’ has come to have unfortunate consequences. Their production involves the use of established technology applied to an atypical reservoir, but the public may associate the term ‘unconventional’ with the technology, which is therefore deemed to be experimental and thus high risk.

In 2000, the US Geological Survey (USGS) [7] published a definition of what were effectively geologically unconventional hydrocarbon accumulations. The survey called these ‘continuous-type deposits’. A continuous-type deposit is ‘a petroleum accumulation that is pervasive
throughout a large area, that is not significantly affected by hydrodynamic influences... Continuous type deposits lack well-defined downdip water contacts'.

(a) Resource plays

The oil and gas industry never fully adopted the term ‘continuous-type deposits’, partly because not all tight gas deposits actually fall within this definition. Instead, the term ‘resource plays’ was widely adopted, especially with regard to gas. Resource plays have certain characteristics that make them attractive to petroleum E&P companies. The exploration of resource plays carries little risk because of the large known in-place resource and great areal extent. The appraisal process normally consists of searching for high-yielding ‘sweet spots’. Resource plays also have long-life reserves. Booked reserves are only a small proportion of the total potential, and reserve additions are essentially made by development drilling. With certain exceptions (e.g. oil sand mining), recovery factors are generally low, so there is therefore plenty of opportunity to reap the dividend of technological improvement. Finally, the ‘assembly-line’ development process results in stable, predictable production rates from resource plays. The typical long project life provides the opportunity to improve efficiency and reduce costs, and also offers security of supply.

Resource plays also have many downside aspects. Compared with conventional E&P, drilling and completing a producing well is complex, and therefore expensive. Certain processes, such as oil upgrading, are capital intensive. There is a relatively low EROI [8], which, in turn, generally results in relatively high greenhouse gas (GHG) emissions per unit of production. Production methods may require significant volumes of water. High gas recovery requires a high well density. In oil sands, shale oil and unconventional gas production, there is potential for groundwater contamination. Nevertheless, innovative solutions have been found to many of the above-mentioned problems and more will undoubtedly follow.

(b) Unconventional hydrocarbon types

Geologically unconventional hydrocarbons are solid, liquid or gaseous hydrocarbons that have been generated over geological time from organic matter in source rocks, and which may also have been modified subsequently, especially in the case of solids and extra-heavy liquids.

— Solid: bitumen in sandstone or carbonate (e.g. oil sands, Alberta, Canada).
— Liquid: extra-heavy oil (e.g. Orinoco Oil Belt, Venezuela);
  tight oil in shale, siltstone or carbonate (e.g. Bakken Shale, Williston Basin,
  USA/Canada);
— Gaseous: tight gas in sandstone or limestone (also called basin-centred gas or deep gas);
  gas in coal (also known as coalbed gas; coal seam gas; coalbed methane);
  gas in shale;
  gas hydrate in unconsolidated marine sediment and continental permafrost
  areas.

These resources are trapped in an unconventional manner and can be exploited economically only by means of unconventional production methods.

3. Key technologies for unconventional hydrocarbon production

Unconventional hydrocarbons differ from conventional hydrocarbons in their production, transportation or processing. As such, the costs of unconventional production have traditionally been higher, because of the complex technologies that their exploitation requires. There is a public perception that the technologies involved in unconventional hydrocarbons are novel, and therefore high risk. In fact, although production technology is continually evolving, the key technologies involved have usually existed for decades. We briefly describe here some of the
key production technologies applicable to unconventional hydrocarbons, and their particular applications.

(a) Horizontal drilling

Rather than drill vertically through a reservoir, a horizontal well remains within the productive unit by drilling laterally through it. Although more costly to drill, a horizontal well can have a total exposure to the reservoir rock surface that is orders of magnitude greater than that of a vertical well (consider, for example, a borehole drilled for 1000 m along a 2.5 m thick coal seam). This greatly reduces the number of wells required, the cost and the surface expression of drilling and production.

The first recorded true horizontal oil well was drilled in Texas in 1929. Sporadic use of the technique was then made in the USA, China, the USSR and elsewhere, but it was not until the early 1980s that the technique began to be used commercially, commencing in France and Italy. In 2009, the number of horizontal wells drilled in North America exceeded the number of vertical wells for the first time. In August 2013, 60% of all wells being drilled in the USA were horizontal.

The first horizontal well for shale gas exploitation was also drilled in the USA, in 1986, when the US Department of Energy collaborated with industry to complete an air-drilled, 2000 feet long horizontal well. The first attempts to drill commercial horizontal shale gas wells were made in the Barnett Shale in the early 1990s but were uneconomic. When these wells were re-entered from 2001 onwards and hydraulically fractured (see below) using the later ‘slick water’ technology, their productivity increased significantly.

Application: oil sands; extra-heavy oil; tight oil; shale gas; coal seam gas; tight gas.

(b) Multilateral wells

A multilateral well is one where more than one horizontal or near-horizontal lateral well is drilled from a single main bore. Laterals can be ‘stacked’, i.e. drilled at different depths, as in coal seams, or splayed to exploit a single interval in different directions. Multilateral wells are used to reduce the number of horizontal wells required, again reducing drilling costs and surface footprint. The first multilateral well was drilled in Bashkiria in southern Russia in 1953. By 1980, 110 multilateral wells had been drilled in the USSR [9].

Application: oil sands (minor); extra-heavy oil; tight oil (minor); shale gas (minor); coal seam gas; tight gas.

(c) Measurement while drilling, logging while drilling and geosteering

Geosteering is the directionally controlled drilling of a well, usually to keep it within the productive zone, and is an essential requirement of horizontal drilling. To achieve this, it is necessary to acquire information while the drilling process is ongoing. Measurement while drilling obtains information such as borehole inclination, azimuth and rate of penetration. It has been in widespread use since the 1960s.

In the 1980s and 1990s, a large suite of conventional well-logging tools became available (e.g. gamma ray; resistivity; neutron) as logging while drilling technology. This permitted interpretation of lithology, porosity and fluid content to be undertaken while drilling, allowing drilling direction decisions to be based on geological and petrophysical information.

Application: oil sands; extra-heavy oil; tight oil; shale gas; coal seam gas; tight gas.

(d) Hydraulic fracturing

Hydraulic fracturing (‘fracking’) fractures rocks by injecting high-pressure fluids down boreholes. It can be undertaken at multiple points (‘stages’) along a horizontal wellbore. In the USA, the development of shale oil and shale gas deposits can now involve as many as 40 fracking stages.
over boreholes 10,000 feet long. Hydraulic fractures propagate when fluid pressure exceeds the least principal stress and the tensile strength of the rock. It is assumed that they propagate in a roughly radial planar manner from around a wellbore, but the actual fracture pattern is likely to be irregular and will depend on the prevailing stress directions, on bedding-plane orientation and on natural fracture systems encountered. Once formed, the microscopic fractures are kept open by injected proppant, normally sand grains.

The principal objective of fracturing is to create permeability where little or none previously existed, improving the connectivity between hydrocarbon-filled pores and the wellbore. In shales, porosity is low, so the propped-open fractures also create reservoir space (fracture porosity) where none existed previously, and increase exposure of rock surface to the wellbore. In the case of shale gas, this permits gas adsorbed on mineral surfaces to migrate into the fractures as free gas when pressure declines. It remains the case that the geomechanical effects of fracturing are not fully understood and in any case vary from shale to shale, within each shale and within each well. Operators therefore tend to learn from empirical experience rather than from predictive techniques.

The first attempt to induce fractures in a shale gas well was in New York State in 1857. This was done by lowering a canister containing eight pounds of gunpowder to the bottom of a 4 feet diameter 122 feet deep unproductive well, connecting it to the surface with a hollow tin tube and dropping a red hot iron down the tube. The explosion expelled the water from the shaft, following which there was a 'plentiful supply of gas'.

In 1947, the first experimental attempt to hydraulically fracture a well was undertaken on a limestone reservoir in the Hugoton gas field in Kansas, using gasoline thickened with napalm as a hydraulic fluid [10]. Two years later, the first commercial fracturing treatments were carried out in Oklahoma and Texas. In the first year of operation, 332 wells were treated. By 2008, the annual number of fracturing stages completed worldwide had risen to 50,000 [10].

The greatest public concern regarding hydraulic fracturing has been the potential for contaminating drinking water and surface water by the materials involved. Some 99.5% of what is injected typically involves fresh water (80.5%) and sand proppant (19%) to keep the induced fractures open. The remaining 0.5% comprises chemical additives intended to dissolve minerals, minimize friction, increase viscosity (to transport the proppant), remove pipe scale, remove oxygen from water, reduce corrosion and kill bacteria.

Application: tight oil; shale gas; tight gas.

(e) Microseismic monitoring

Microseismic monitoring has been used commercially since around 2000. It involves the placement of receivers in an adjacent observation well or on the surface and recording the microseismicity induced by the fluid injection process. The monitoring allows the hydraulic fracturing process to be adapted to evolving circumstances in real time.

Mapping microseismic events allows the orientation and distribution of induced fractures to be observed. It can identify where reservoir space has not yet been created by fracture propagation. More importantly, the location and progress of fracture propagation can be measured as it occurs. This allows fracture propagation to be halted before fluids enter the fracture system of previously completed wells, or reach geohazards such as faults or overlying or underlying permeable strata into which oil or gas could escape.

Induced seismicity is a further public concern about hydraulic fracturing, especially in populous areas. This was brought to prominence in 2011 when the Preese Hall 1 well in Lancashire, UK, was fracture stimulated. The vertical well was due to have a 12 fracking stage completion between 5260 and 9000 feet, but after five stages, fracturing was suspended owing to two small earthquakes near the well (2.3 and 1.5 Richter local magnitude). The British Geological Survey subsequently determined that the earthquakes were the result of the fracturing process. The well operator and the Department of Energy and Climate Change (DECC) concluded that the repeated seismicity resulted from direct injection of fluid into the same critically stressed fault
zone, and that this can be avoided in future by rapid flow-back after treatment and reduction in treatment volume, accompanied by real-time seismic monitoring to initiate appropriate action when seismic magnitude exceeds predefined thresholds [11,12].

Application: tight oil; shale gas; tight gas.

4. Unconventional hydrocarbon liquids

This section examines each of the three main sources of unconventional liquids, with a geological overview of each resource, a description of the main methods of extraction and production, and notes on some economic issues and environmental concerns raised by its exploitation.

(a) Tight self-sourcing oil

Tight self-sourcing oil plays occur when an oil-prone organic-rich source rock with low permeability (mudstone, shale, limestone or chert) is thermally mature, but the generated hydrocarbons have remained largely in place because of limited fluid mobility. The hydrocarbons are extracted either from the source rock itself, or from slightly more porous interbeds (such as siltstone within a shale source), or from tight but porous lithologies in immediate contact with the source rock. The hydrocarbon is generally a light oil.

The best self-sourcing oil plays have high oil content and either a high carbonate content or a mixture of interbedded rock types that enhance the storage of any expelled oil and provide the brittleness essential for natural or artificial fracture formation. Good upper and lower bounding impermeable rock units (seals) also help to retain the oil.

Such plays have been known for several decades, and they have yielded minor production over that time, but it is only in the past few years that the combination of high oil prices and developments in horizontal drilling and hydraulic fracturing have made them an attractive target for exploitation. Potentially, however, they are the most commercially interesting unconventional hydrocarbon liquid plays, because the appropriate conditions occur widely around the world, whereas major oil sands and extra-heavy oil deposits tend to be geological rarities.

(i) Global resources

Historically, the two best-known occurrences of tight self-sourcing reservoirs have been the ‘shale oil’ plays of the Bakken Formation in the Williston Basin of USA and Canada, and the largely undeveloped Bazhenov Formation in West Siberia. As the true production potential of such plays has only been realized in the past decade, the location and extent of the global resource are unknown. Estimates of in-place resource are generally based on a calculation of how much oil has been generated from within the unit. If any oil is thought to have migrated subsequently, then an estimate of the lost volume must also be made. Estimates for a number of the most prolific US tight self-sourcing liquid plays indicate a combined recoverable resource in excess of 33 Gb [4].

(ii) USA and Canada

The Bakken Formation of North Dakota, Montana, Saskatchewan and Manitoba covers 520 000 km². The oil source is oil-prone black shale of the Upper and Lower Bakken Members, with the main production horizon being the Middle Bakken Member. Estimates of the generated oil volume range from 10 to 500 Gb, but recoverable volumes will probably amount to only a few per cent. The mean recoverable oil from the US portion of the Williston Basin (including the Bakken, Lodgepole and Three Forks or Sanish Formations) is estimated at 3.65 Gb [13]. In 2008, the North Dakota Department of Mineral Resources estimated that 2.1 Gb is recoverable within the State from an in-place resource of 149 Gb, but in January 2011 increased the estimate to 5–11 Gb recoverable [14] and by 2012 this had been increased again to 7–14 Gb with a probable estimate for the State of 10 Gb recoverable [15]. Bakken production in the USA was first established in 1953 and in Canada in 1956. It was the discovery of the Elm Coulee field in Montana in 2000
(with the first horizontal wells drilled in the Middle Bakken Formation) that transformed the Bakken from a secondary objective to a major exploration target. Even by 2002, combined US and Canadian Bakken production averaged only 5500 barrels per day (b d$^{-1}$), 38% of which was from the Elm Coulee field, but from 2004 to 2007 the average annual increase in production was 21 000 b d$^{-1}$ (figure 4).

As Elm Coulee production started to plateau, production from North Dakota, Saskatchewan and Manitoba grew rapidly, resulting in average annual production growth of over 90 000 b d$^{-1}$ between 2008 and 2011 and over 250 000 b d$^{-1}$ in 2012. Combined production from the USA and Canada reached 726 000 b d$^{-1}$ in 2012. In 2012, North Dakota Bakken production alone averaged almost 600 000 b d$^{-1}$ and in December 2012 exceeded 700 000 b d$^{-1}$ for the first time. The North Dakota Department of Mineral Resources forecasts plateau production from the Bakken in North Dakota of 800 000–900 000 b d$^{-1}$ between 2014 and 2020, followed by gradual decline.

The inevitable consequence of success in the Bakken has been the search for Bakken analogues elsewhere. The Early Carboniferous Barnett Shale (Fort Worth Basin, North Texas) and the Late Cretaceous Eagle Ford Shale (Maverick Basin, South Texas) are areas where shale gas exploration has extended into areas of oil plays. Significant tight oil production also comes from the Permian Basin (Texas) where the Spraberry, Wolfcamp and Avalon/Bone Springs Formations are the principal producing units.

In California, the Miocene-age, diatomaceous Monterey Shale probably sourced almost all of California’s conventional and heavy oil and is estimated to contain as much as 500 Gb of oil in-place. Production directly from the shale started in 1900 but it is now the focus of renewed interest, and it probably has the largest technically recoverable resource of all of the US tight oil plays [4]. In the Denver and North Park Basins in Colorado, the interbedded limestones and calcareous shales of the Upper Cretaceous Niobrara Formation are another target.

The US Energy Information Administration (EIA) [16] estimates that total US tight oil production reached 2.0 million barrels per day (Mb d$^{-1}$) in 2012 and will peak at around 2.8 Mb d$^{-1}$ in 2020. Tight oil production from the US Bakken/Eagle Ford/Barnett collectively averaged 1.0 Mb d$^{-1}$. The growth in Eagle Ford oil production has been particularly dramatic, from 844 b d$^{-1}$ in 2009 to 352 000 b d$^{-1}$ in 2012 [17]. Production continued to increase in 2013. Average daily production from the North Dakota Bakken and Eagle Ford was 300 000 b d$^{-1}$ higher in the first five months of 2013 than over the whole of 2012, an increase of 30%.

In Canada, in addition to the Bakken Shale, tight oil is produced from the Cardium (Cretaceous) and Lower Shaunavon (Jurassic, Alberta) Formations and the Viking Formation.

**Figure 4.** Bakken–Three Forks source system oil production, Williston Basin, 2002–2012, by State/Province. (Online version in colour.)
(Cretaceous, Alberta and Saskatchewan). Throughout North America, over 20 tight self-sourcing oil reservoirs are now the focus of investigation and 11 of these are already in production.

(iii) Russia

The Upper Jurassic Bazhenov Formation is a marine black shale that is the source rock for 90% of the conventional oil in the West Siberian Basin. The shale is itself productive in the Greater Salym area, and has produced at rates of up to 3500 b d\(^{-1}\). Reservoir zones are small and located close to fault planes. Production to date is only from faulted zones, but there is potentially a very large resource. In one 40,000 km\(^2\) area, the in-place resource is 8 Gb, of which 1.7 Gb could ultimately be recovered [18], but the total area of thermally mature Bazhenov Formation is close to \(10^6\) km\(^2\), and a recent Lukoil report indicates a recoverable resource of 80–160 Gb. Lukoil is said to be producing about 2000 b d\(^{-1}\) in initial experimental production. In 2013, Salym Petroleum, a Gazprom/Shell joint venture, plans three to five horizontal Bazhenov wells.

(iv) Argentina

The Vaca Muerta Formation (Upper Jurassic or Lower Cretaceous) in the Neuquen Basin is attracting most interest. The Argentine energy company YPF has achieved initial production in the range 200–600 b d\(^{-1}\) per well from 15 vertical wells on one block, from which recoverable resources were originally estimated at 741 Mb. In February 2012, Repsol announced that recoverable reserves of the entire play may be nearly 23 Gb.

(v) Other countries

Lower Jurassic source rocks in the Paris Basin are estimated to contain 65 Gb of tight oil in-place, but a law was passed in 2011 that prohibited the exploration for, and production of, liquid or gaseous hydrocarbons by hydraulic fracturing. In the South Oman Salt Basin, completely encased in salt, the low-permeability organic-rich laminated chert of the Athel Formation produces 20 million barrels per year from about 16 wells in the Al Noor field. Not only is the reservoir setting unique but the age of the source–reservoir system, straddling the Precambrian–Cambrian boundary, makes it one of the oldest commercial accumulations in the world. Other potential targets worldwide include the Whangai and Waipawa Shales in New Zealand’s East Coast Basin, European shales such as the Kimmeridge Clay and Posidonia Shale, and Chinese shale formations.

(vi) Extraction and production

The key to production from tight self-sourcing oil reservoirs lies in improvements in well drilling and completion technology, allied to high oil prices, which make these technologies economic. Such reservoirs are now being developed by multiply-fractured horizontal wells. Wells with horizontal legs of 3000 m or more are now being drilled, with as many as 40 sets of hydraulic fractures being created along them. In the case of the Bakken Shale, productivity is greatest where hydraulic and tectonic fractures occur together.

A typical North Dakota Bakken well has initial production of 900 b d\(^{-1}\) and is forecast to decline to 65 b d\(^{-1}\) after 5 years, to 20 b d\(^{-1}\) after 25 years, and to cease production at 7 b d\(^{-1}\) after 45 years, producing 615,000 barrels of oil over its productive life [19]. Large numbers of wells will therefore be required to recover the full potential of the North Dakota Bakken. At end July 2012, there were 4300 drilled and completed Bakken wells in North Dakota. It is estimated that a further 36,000 will be required over the next 20 years, using some 200 drilling rigs. In August 2012, there were 208 active rigs in North Dakota [19].

In the 3 years to end December 2012, average daily production per well in North Dakota remained within the range 122 to 145 b d\(^{-1}\), with 2012 averaging 142 b d\(^{-1}\). Production from new wells is therefore currently offsetting decline in older wells. The surface impact of drilling is
being reduced by deviating multiple wells from a single well pad location. Wells currently cost an average of US$9 million to drill and complete, and are expected to generate a net profit of US$20 million over their productive life [19].

(b) Oil sand bitumen

Oil or tar sands are naturally occurring mixtures of bitumen and water in a host rock of sand or sandstone with minor clay minerals or, less commonly, in limestone. Most definitions of bitumen specify a density greater than 1.00 (less than 10° API) and viscosity greater than 10 000 centipoise (cP). Bitumen is a sticky, asphaltic form of degraded crude oil that is effectively solid at temperatures less than 11°C. After extraction, it is either upgraded to form a synthetic crude oil (SCO) or, if heated or diluted to reduce its viscosity, piped directly to refineries to be processed and refined. Oil sands can be either mined or else heated and produced in situ.

Canadian oil sand mines average 11% bitumen and 4% water by weight. On average, two tonnes of oil sand (approx. 1 m³) contains one barrel of bitumen, which, in turn, yields about 0.85 of a barrel of SCO. Oil sand mining and extraction is very efficient, with over 90% of bitumen being recovered from oil sand deposits in some operations. This is a considerably better recovery rate than that of conventional light oil deposits, which rarely exceed 50%. In Canada, the recovery rate for in situ production from oil sands is routinely 40–50% and can potentially reach 80%.

(i) Global resources and major occurrences

The global in-place bitumen resource is likely to exceed 3000 Gb. The oil sands of Alberta alone may have an ultimate potential of 2500 Gb of bitumen in-place, approximately twice the volume of liquid hydrocarbons that has been produced throughout the world over the past 150 years, although only a fraction can ever be recovered. Major bitumen deposits have also been discovered in Russia, Kazakhstan and the USA.

(ii) Canada

Canadian oil sands are potentially the second largest national source of oil in the world after the conventional reserves of Saudi Arabia. Production in Canada is concentrated in Alberta, where the oil sands cover 142 000 km² of the region’s boreal forest in three formal oil sands areas (OSAs), Athabasca, Peace River and Cold Lake. In general, oil sand mines are located in the central Athabasca deposits, north of the mining town of Fort McMurray. By contrast, in situ production is used in the southern Athabasca, Cold Lake and Peace River deposits. The shallow, minable portion covers 4750 km² [20]. The resources of the Alberta deposits are indicated in table 1. Saskatchewan also has a potential in-place resource of some 60 Gb of bitumen.

Geology

Some 69% of the established in-place bitumen resource of 1844 Gb occurs in unconsolidated sands of the Lower Cretaceous Mannville Group, though the principal reservoirs vary between the different OSAs. The remaining 573 Gb occurs in highly eroded, vuggy and karstic carbonate reservoirs, including the Devonian Grosmont and Nisku Formations (Athabasca OSA—508 Gb) and the Lower Carboniferous Debolt and Shunda Formations (Peace River OSA—65 Gb). Although these carbonates have not been exploited commercially, there has been some experimentation with in situ recovery methods.

The oil precursor to the bitumen came from a variety of source rocks ranging in age from the Upper Palaeozoic to the Mannville Group itself lying in the deep southwestern part of the Western Canadian Sedimentary Basin [21]. The oil migrated into place during the Late Cretaceous and Early Tertiary. From Eocene times onwards, uplift of the shallow eastern margin of the basin

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1API gravity, an oil density measurement, is defined as (141.5/specific gravity) – 131.5.
Table 1. Oil sand resources and reserves (as defined in ‘terms’ above) of Alberta, Canada.\(^a\)

<table>
<thead>
<tr>
<th>Alberta oil sands resources</th>
<th>established bitumen resource initially in-place</th>
<th>ultimate bitumen resource initially in-place</th>
<th>initial established recoverable bitumen resources</th>
<th>ultimate recoverable bitumen resources</th>
<th>cumulative production</th>
<th>remaining established recoverable bitumen resources</th>
<th>ultimate remaining recoverable bitumen resources</th>
<th>remaining developed reserves</th>
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<td>billion barrels</td>
<td>1845</td>
<td>2500</td>
<td>176.8</td>
<td>315.0</td>
<td>7.9</td>
<td>167.9</td>
<td>306.2</td>
<td>25.9</td>
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<tr>
<td>remarks</td>
<td>293.125 bcm</td>
<td>400 bcm</td>
<td>28.092 bcm</td>
<td>50 bcm</td>
<td>end 2012.</td>
<td>Initial established bitumen resources minus 8.8</td>
<td>Ultimate bitumen resources minus 8.8</td>
<td>3.7 bcm mining; 0.4 bcm in situ and primary recovery</td>
</tr>
<tr>
<td></td>
<td>(11 bcm mining; 33 bcm)</td>
<td></td>
<td></td>
<td>(in situ; 6 bcm)</td>
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<tr>
<td></td>
<td>Cretaceous in situ</td>
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<td>Upper Paleozoic in situ)</td>
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\(^a\)ERCBC, Alberta Energy Resources Conservation Board; EUB, Alberta Energy & Utilities Board; NEB, National Energy Board. bcm, billion cubic metres.
Table 2. Canadian oil sands production forecasts for year 2012 compared with actual production.

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<td>year 2012</td>
<td>1.918</td>
<td>2.321</td>
<td>2.259</td>
<td>1.743</td>
<td>1.808</td>
<td>1.760</td>
<td>1.771</td>
<td>1.787</td>
</tr>
</tbody>
</table>

led to the influx of oxygenated meteoric water. The resultant microbial biodegradation of the oil produced the bitumen, through the loss of lighter hydrocarbons and the concentration of heavier hydrocarbons, sulfur and heavy metals such as nickel and vanadium.

**Development**

Only 7% of Alberta’s established in-place resource is accessible by mining, with the remainder requiring *in situ* processing (see below). Surface mining, however, has higher average recovery factors and a much longer production history. As a result 22% of the initial established recoverable resource is considered to be minable, and mining accounted for 48% of bitumen production in 2012. Of the 25.9 Gb of remaining developed and developing reserves, 90% are attributable to mining and 10% to *in situ* methods [20]. No recoverable resource or reserves are yet attributed to carbonate formations, as there are no commercial operations. Of the ultimate potential recoverable resource of 315 Gb of bitumen, 22% has been attributed to mining, 66% to *in situ* recovery from Cretaceous clastic sediments and 12% to Upper Palaeozoic carbonates.

Assessments of Canada’s oil sand resources were made as early as the late 1800s [22]. Commercial production began in September 1967. Most major independent oil companies are involved in Canadian oil sands projects, as well as many smaller companies. State-controlled companies from China, Japan, Korea, Thailand and Norway, and sovereign wealth funds from Korea and China, have also acquired interests.

In 2012, bitumen production averaged 1.922 Mb d$^{-1}$, equivalent to 1.787 Mb d$^{-1}$ of liquids production (owing to losses on SCO conversion). This latter volume represented 55% of Canadian oil and condensate production excluding natural gas liquids (NGLs). The Canadian Association of Petroleum Producers (CAPP) [23] has forecast that oil sands output from Alberta will exceed 2 Mb d$^{-1}$ by 2014, reaching 2.3 Mb d$^{-1}$ in 2015 and 3 Mb d$^{-1}$ by 2020, and exceeding 4 Mb d$^{-1}$ by 2023 and 5 Mb d$^{-1}$ by 2029. The International Energy Agency (IEA) forecasts for 2015, 2020, 2025 and 2030 are 2.4, 2.8, 3.3 and 3.7 Mb d$^{-1}$ [24].

Long-term historical oil sands production forecasts have always erred on the generous side. Table 2 shows a range of forecasts for production in 2012. The forecast made 6 years ahead in 2006 overestimated production by 30% and even the forecast published in June 2010 was an overestimate. Estimates to 2020 and beyond should therefore be treated with considerable caution.

(iii) Russia

Bitumen resources in Russia are difficult to assess because of Russian terminology, both in the meaning of the word ‘resource’ and because certain extra-heavy crudes (‘malthas’) may be included with bitumen. The USGS [25] has estimated that Russia has 33.7 Gb of technically recoverable bitumen, plus a further 212.4 Gb of bitumen in-place in small deposits or remote locations. Other estimates of total Russian in-place bitumen resources, including the most recent USGS estimate, range from 200 to 347 Gb.

The best endowed region is in the Volga–Ural Basin, especially Tatarstan, where the Mordovo–Karmalskoye field commenced pilot production from Permian sandstone in 1978, mostly from
in situ processes. Other major resources are found in the Olenik Highland in the Lena–Anabar Basin in remote Eastern Siberia, where deposits occur in rocks ranging in age from Late Proterozoic to Early Jurassic. In the Timan–Pechora Basin, bitumen deposits occur in Upper Devonian carbonates and Lower Mississippian sandstone and carbonate reservoirs.

(iv) Kazakhstan

Substantial bitumen resources are believed to exist in western Kazakhstan in the Aktyubinsk, Mangistau and West Kazakhstan oblasts (regions). Estimates of the resource volume vary, but the most recent estimate places the in-place resource at some 420 Gb, second to Canada [26]. Such is the size of Kazakhstan’s conventional oil resource, however, that any large-scale development is unlikely in the medium term.

(v) USA

US oil sand resources contain between 54 [27] and 76 Gb [28] of original oil in-place, of which an estimated 11 Gb may ultimately be recoverable [29]. The largest US deposits are located in eastern Utah, where there have been two pilot operations. The Utah oil sand deposits differ from those of Canada in that they typically occur in consolidated sandstones, and are therefore less amenable to mining. In addition, the bitumen is in direct contact with the sand grains, whereas, in Canada, the bitumen is separated from the sand grains by a film of water. They may therefore require different extraction technologies, as hot water extraction will be unsuitable. The second largest US resource is thought to exist in the Tertiary-age Ugnu Sands on Alaska’s North Slope, and there are also significant resources in Texas, Kentucky, Alabama and California.

(vi) Other significant occurrences

Bitumen has been mined in Albania for a number of centuries, in Switzerland from 1712 to 1986, in Trinidad since the early 1800s, and in the Democratic Republic of Congo (Kinshasa) and Indonesia during the twentieth century. Significant bitumen resources also exist in Nigeria, Venezuela and China. In Madagascar, the Bemolanga oil sand deposit was evaluated by Total to confirm that it holds sufficient resources to underpin a mining operation, but the appraisal did not confirm the feasibility of development. The in-place bitumen resource has been estimated at three billion tonnes (21 Gb) [30]. Published estimates of recoverable bitumen range between 2.5 and 10 Gb.

(vii) Production

Canadian surface mining

Surface mining of bitumen in Canada commenced in 1967. In 2012, there were five operating mines in Alberta (Suncor, Syncrude, Muskeg River, Jackpine and Horizon), and a sixth, Kearl, commenced production in April 2013. Two other projects have been approved (Fort Hills and Joslyn North) but await a final investment decision. Other than the scale of the operations, which collectively remove about two million tonnes of ore per day, the principal challenges are environmental: coping with the extremely low temperatures of the Alberta winter and minimizing the impact of the operations on water resources and fragile ecosystems.

Surface operations involve mining the ore, extracting the bitumen and upgrading the bitumen into products including SCO. SCO is in many ways comparable with light sweet crude, but its high aromatic content limits its acceptability in non-specialized refineries. A typical refinery is limited to 10–20% of SCO in its crude feedstock.

The mining operation first removes muskeg (bog) and soil, which is either stored or recycled immediately for reclamation purposes, and then the barren overburden rock. Total overburden depths of 50 m are common, and the maximum overburden depth used to define the surface
minable area is generally less than 65 m. Initially, mining was carried out by bucketwheel or dragline, with subsequent transport by conveyor belt, but frequent breakdown in harsh winter conditions resulted in a move to truck and shovel mining. The shovels scoop up 100 tonnes of ore at a time and load 400 tonnes into 300 tonne trucks, for transport to a crusher.

The crushed ore is mixed with warm water (35–50°C), and the slurry transported by pipeline to the extraction plant. During the turbulent pipeline transport, sometimes for several kilometres, the bitumen starts to separate from the host rock. At the extraction plant, the slurry is agitated with hot water, caustic soda and air or steam, creating a bitumen-enriched froth. The separated sand is used as mine backfill and for reclamation, whereas silt and clay fines are sent to tailings ponds, and the water is recycled.

The bitumen froth is the upgrader feed. Bitumen comprises large hydrocarbon molecules, which must be split into smaller molecules. In Alberta, this is generally done by carbon removal (‘coking’), which creates substantial quantities of residual coke by-product and produces only 0.85 of a barrel of upgraded bitumen for each barrel of bitumen input. Rather than removing carbon, adding hydrogen (‘hydro-cracking’) can produce 1.03 barrels of product per barrel of bitumen. Upgrader end products are ‘sweet’ (sulfur content less than 0.5%). Between them, Canadian upgraders produce light and heavy sweet and medium sour SCO, diesel fuel, bitumen diluent and intermediate refinery feedstock.

**Canadian subsurface (in situ) production**

There are several commercial and experimental methods of subsurface production. Most in situ production comes from variants of two basic thermal methods for melting the bitumen: cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD). At present, thermal methods that involve steam injection under pressure require a minimum depth to reservoir of 200–300 m. This means that there is currently an undeveloped zone between the maximum mine depth (100 m) and the minimum in situ depth.

CSS (‘huff-and-puff’) is an older method, accounting for 26% of all Alberta in situ production in 2012, when some 3700 wells averaged 70 b d⁻¹ of bitumen per well [20]. CSS involves the injection of steam at 310°C and 1450 psi in vertical, deviated or horizontal wells, which fractures the bitumen-bearing reservoir. After injection is completed, the steam is allowed to ‘soak’ through the reservoir for several weeks to heat and melt the bitumen. Once the bitumen has melted, the wells are used to pump out the resultant hot water and bitumen mixture. When production declines, another cycle of steam injection commences. Complete production cycles normally take six to 18 months. Recovery rates are 10–60% of the original effective bitumen in-place, and average 25%. ‘Effective bitumen’ is normally that at a concentration in reservoir rock of 8% by weight or greater. Since about 2004, the cumulative steam–oil ratio (SOR) has been 3.4 barrels of water per barrel of bitumen produced.

A recent advance in CSS technology involves mixing low concentrations of solvents such as natural gas condensate directly into the steam. Liquid addition to steam for enhancing recovery (LASER) is now in commercial use at Cold Lake as a late-stage technology, applied after several steam cycles have taken place and with two to three cycles remaining. LASER potentially increases the recovery by greater than 5% of bitumen in-place. Environmental benefits include reduced water usage by the substitution of hydrocarbon solvent for 5–10% of steam.

Improvements in horizontal drilling and geosteering technology throughout the 1990s made possible the highly effective SAGD technique. In 2012, 49% of in situ bitumen production came from SAGD wells. The average production per well (613 b d⁻¹) from the 800 producing wells is much higher than for CSS. In SAGD, parallel horizontal well pairs are drilled, one 5 m above the other. Steam is injected through the upper well and bitumen recovered from the lower. Steam injection is at much lower pressures than in CSS. This prevents reservoir fracturing, allowing shallower reservoirs than the 400 m deep reservoir at Cold Lake to be developed. The lower SORs used in SAGD reduce operating costs.
Hybrid SAGD systems similar to LASER-CSS use ethane, propane or condensate in the solvent-assisted process (SAP). By reducing the oil viscosity, the overall effect should be an improved oil to steam ratio (or reduced energy intensity).

Toe-to-heel air injection (THAI) combines a vertical air injection well with a horizontal production well, eliminating the need for a second horizontal steam injection well. The reservoir bitumen is ignited, creating a vertical burning front which thermally cracks some of the bitumen in front of it to low-viscosity liquids and a carbonaceous residue. The liquids drain into the horizontal producer well. THAI offers many potential advantages compared with SAGD, including higher oil recovery, lower production and capital costs, minimal usage of natural gas and fresh water, a partially upgraded crude oil product, reduced diluent requirements for transportation and significantly lower GHG emissions than SAGD (which has high emissions and low EROI). The THAI process can also operate in reservoirs that are lower in quality, thinner and deeper than SAGD. THAI production wells from Petrobank’s Kerrobert project averaged 160 b d$^{-1}$ in July 2013.

At Peace River, commencing in 2004, Shell experimented with in situ thermal upgrading of bitumen using 18 electric heater wells and three production wells. The heaters warmed the bitumen, producing light, clean, low-viscosity oil and leaving a solid carbon (coke) residue. Over 100 000 barrels of $30^\circ$–$49^\circ$ API light oil were produced at 50% recovery versus the 20% achieved there using CSS.

VAPEX is a non-thermal bitumen production method that has undergone trials using paired horizontal wells, a vertical and a horizontal well or vertical wells only. Solvent (e.g. ethane, propane or butane) plus a displacement gas are injected into the reservoir to mobilize the hydrocarbons and move them towards the producing well. The key benefits are significantly lower energy costs, potential for in situ upgrading, and application to thin reservoirs. N-Solv is another solvent process that includes heating to 40$^\circ$C.

Simple primary production (including water and polymer injection) also accounted for 25% of in situ production in 2012. More wells (approx. 7000) are devoted to primary production than to thermal methods, but the productivity is low, averaging 35 b d$^{-1}$ per well in 2012.

In Cold Lake, primary production is based on cold heavy oil production with sand (CHOPS) technology [31]. Heavily perforated vertical wells with progressive cavity pumps produce a mixture of bitumen and sand. CHOPS wells can produce from 0.5 to 8% sand by volume over a life of 5–15 years, increasing oil production by a factor of 10. CHOPS can also be used as a precursor to CSS in thin reservoirs by reducing horizontal pressure and disrupting shale interbeds, permitting the steam to propagate much more effectively. Basic primary recovery factors are generally low (5–10%) but can be up to 16% with CHOPS.

**(viii) Issues**

The Canadian oil sands industry faces economic, infrastructural, regulatory and social issues resulting from the environment within which it operates.

The economic issues include costs, labour supply, long project lead times, environmental remediation and the future oil price. Canadian oil sands projects are extremely oil-price sensitive. As oil prices dropped from their peak of July 2008, annual capital expenditure fell from over C$18 billion in 2008 to C$11 billion in 2009. However, with the global recession, both capital and operating costs declined in 2009, by approximately 15% and 13% respectively. Capital expenditure is forecast to reach C$20 billion in 2012 after record expenditure of C$19 billion in 2011 [32]. In 2009, the Canadian Energy Research Institute estimated the capital cost per barrel per day of oil production was C$27 000 for an in situ project, C$82 000 for mining and C$101 000 for a mining and upgrading operation. In 2012, these estimates had changed to C$32 000, C$73 000 and C$123 000, respectively.

Significant technical extraction issues remain if Alberta’s entire oil sands resource is to be exploited. These include producing the 30% of the resource that is located in carbonate formations.
or in the intermediate depth range below mining and above drilling. Potential technical solutions include:

- more well-based operations, being cheaper than mining;
- innovative technology;
- co-generation to reduce steam cost;
- bitumen processing methods that generate fuels as by-products (H₂, syngas);
- diluent recycling, or SCO as an alternative to diluent (producing a bitumen–SCO mixture termed Synbit); and
- product upgrading to improve marketability.

The major infrastructure issues are refinery and pipeline limitations. As noted previously, SCO makes specific demands of refineries owing to its aromatic-rich composition. The transportation problem reflects a crude supply bottleneck at the US oil distribution hub of Cushing, Oklahoma, where Canadian exports pass through on the way to US Gulf Coast refineries. There is also insufficient pipeline capacity to move oil to West Coast refineries. Various pipeline projects are expected to be completed between 2013 and 2017 that will resolve this issue, but the problem may recur as light shale oil production builds up in the Williston Basin, on both sides of the USA/Canada border.

The principal oil sands environmental issues can be summarized as follows:

- energy-intensive production with high GHG emissions;
- impact on land through forest fragmentation and tailings disposal;
- water extraction and disposal;
- air emissions and quality, including SO₂, NOₓ, H₂S, CO, ozone and particulates; and
- disposal of by-product carbon and sulfur.

Oil sands production is energy intensive. In 2007, Shell’s Athabasca Oil Sands Project (mining and upgrading) used the energy equivalent of one barrel of SCO to produce 6.7 barrels of SCO [33]. This compares with a typical EROI for conventional oil production of about 20. The direct oil sands to syncrude EROI, combining mining and in situ methods, is around 5.8 [34]. Given the higher EROI for mining and the high energy cost of steam, SAGD and CSS technologies probably have an EROI of 5 or less, although THAI is estimated to have an EROI of about 9 [35]. Solar-powered steaming would raise EROI values. Although overall oil sands GHG emissions are rising, the emissions per barrel are falling.

Individual mine areas are some 150–200 km², and the future reclaimed landscape will typically have 10% less wetlands, more lakes and no peatlands [36]. In situ production has less impact (10–20% footprint versus 150%) but it fragments the surface with roads and seismic lines. Serious attempts are being made to undertake reclamation with an ecological, social and cultural ethos.

Mining operations withdraw 2–4.5 barrels of water (primarily from the Athabasca River) per barrel of SCO. As of late 2010, oil sands mining operations had permission to use just over 2% of the Athabasca River’s average annual flow, which can be cut during the river’s low-flow periods, but actual usage was less than 1%. Groundwater must also be removed from around pits to prevent flooding, which can result in reduced flows to peatlands, wetlands and surface water bodies. Actions taken include storage of water on mine properties to compensate in low river flow periods, and recycling of mine waste water. Projects are under way to reduce tailing pond reclamation time from 40 to 10 years.

SAGD operations consume 0.2 barrel of additional deep groundwater per barrel of bitumen. New policies will reduce or eliminate the use of fresh water for in situ projects. The treatment of saline groundwater, however, produces large volumes of solid waste, containing acids, hydrocarbon residues and trace metals. The Cold Lake CSS project now recycles over 90% of produced water, and has cut water use from 4.5 in 1985 to 0.36 barrel per barrel in 2010 [37].
Elemental sulfur is a major by-product, expected to reach five million tonnes per year by 2015, for which China and India are potential markets. Since 1996, 40 of China’s 600 fertilizer plants have used Canadian sulfur instead of burning pyrite, saving 250,000 tonnes of CO2 per year.

The gasification of asphaltenes and coke to produce heat, hydrogen and fuel gas (syngas) disposes of carbon, reduces GHGs per unit of net production, reduces natural gas requirements and produces excess electricity for export. Upgrading within reservoirs (e.g. THAI or electrical heating) or microbial fermentation to convert bitumen to methane can also reduce GHGs. Fermentation generates only some 1000 cubic feet of methane from a barrel of bitumen, wasting 85% of the contained energy of the bitumen.

CO2 sequestration by injection into storage reservoirs, and CO2 injection for enhanced oil recovery in conventional reservoirs, have both been suggested, but require a pipeline from Fort McMurray to central Alberta. Integrated CO2 Network has proposed an integrated pipeline CO2-capture network, whereas Alberta Saline Aquifer Project is a project that is searching for deep aquifers for CO2 storage. Shell’s proposed Quest Project would capture more than one million tonnes of CO2 per year from the Scotford Upgrader at Fort Saskatchewan, Alberta. The CO2 would be transported by pipeline up to 90 km to wells where it would be injected at a depth of some 2300 m for permanent safe storage.

(c) Heavy and extra-heavy oil

Although there are no global definitions of heavy and extra-heavy oil, there is a general consensus for the following in-reservoir values:

- heavy oil density between 0.934 and 1.00 g cm\(^{-3}\) (20° to 10° API gravity);
  viscosity between 100 and 10,000 cP;
- extra-heavy oil density greater than 1.00 g cm\(^{-3}\) (less than 10° API gravity);
  viscosity between 100 and 10,000 cP.

The density of extra-heavy oil is therefore in the same range as that of bitumen, but it has lower viscosity and is liquid and mobile under reservoir conditions. If Venezuela’s large extra-heavy oil deposits existed at the 15°C typical of the Alberta deposits and not the 48–55°C typical of Venezuela, then they too would be solid and not liquid.

Production of heavy oil is generally considered as a standard operation and is treated as conventional production. This section therefore focuses on extra-heavy oil, but many estimates of extra-heavy oil resources are combined with those of heavy oil, complicating analysis of resource volumes.

(i) Global resources and major deposits

Estimated worldwide resources of heavy and extra-heavy oil are substantial and located primarily in Venezuela. Russia and the USA are also major resource holders, although much of the US recoverable resource has already been produced. Many estimates also include bitumen, and it is unsafe to use estimates that do not provide sufficient detail to exclude bitumen resources. One also needs sufficient detail to separate heavy and extra-heavy oil resource estimates, and to know the definitions used.

Table 3 shows some published estimates of global in-place and recoverable bitumen and heavy oil (including extra-heavy oil) resources. The variance in what is being reported makes comparison difficult. Even when data are apparently comparable, estimates are very variable, even in the most recent years (for example, the estimates of bitumen in-place in 2007 vary substantially, because the USGS estimate includes Venezuelan extra-heavy oil from the Orinoco Oil Belt).

The low values in the earliest (1982) estimate reflect the state of knowledge and recovery technology available at that time. Excluding this value and the estimates of 2007–2010, which
Table 3. Published global resource estimates for bitumen and heavy plus extra-heavy oil (billion barrels) [38].

<table>
<thead>
<tr>
<th>Source</th>
<th>Year</th>
<th>In-place</th>
<th>Recoverable</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>bitumen</td>
<td>heavy/EH oil</td>
</tr>
<tr>
<td>Meyer et al. [39]</td>
<td>1982</td>
<td>5000</td>
<td>174</td>
</tr>
<tr>
<td>Meyer &amp; Schenk [40]</td>
<td>1985</td>
<td>3553</td>
<td>2706</td>
</tr>
<tr>
<td>Meyer &amp; de Witt [41]</td>
<td>1990</td>
<td>2720</td>
<td></td>
</tr>
<tr>
<td>Tedeschi [42]</td>
<td>1991</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Meyer [43]</td>
<td>1997</td>
<td></td>
<td>170</td>
</tr>
<tr>
<td>Attanasi &amp; Meyer [44]</td>
<td>2004</td>
<td>3594</td>
<td>2064</td>
</tr>
<tr>
<td>IFP/Total [45]</td>
<td>2007</td>
<td></td>
<td>4700</td>
</tr>
<tr>
<td>Saniere &amp; Lantz [46]</td>
<td>2007</td>
<td>3517</td>
<td>1220</td>
</tr>
<tr>
<td>USGS (Meyer et al.) [47]</td>
<td>2007</td>
<td>5505</td>
<td>3396</td>
</tr>
<tr>
<td>Attanasi &amp; Meyer [48]</td>
<td>2007</td>
<td>3272</td>
<td>2484</td>
</tr>
<tr>
<td>Attanasi &amp; Meyer [26]</td>
<td>2010</td>
<td>3329</td>
<td>2150</td>
</tr>
</tbody>
</table>

are based on reserves rather than resources, the range in global resource estimates of recoverable bitumen, heavy and extra-heavy oil is quite small (893–1085 Gb).

(ii) Venezuela

The extra-heavy oil resources of Venezuela are found in eastern Venezuela in the Orinoco Oil Belt, an area of some 50 000 km². There are additional resources in the Maracaibo Basin, in the Boscan and Garcia fields. The most authoritative source of information is the State oil company, Petróleos de Venezuela S.A. (PDVSA; table 4).

The latest PDVSA estimate, of established recoverable resources of 262.6 Gb from an in-place resource of 1338 Gb, implies a recovery factor of 20%. The estimated recovery factor from the four
### Table 4. Extra-heavy oil resources and reserves of the Orinoco Oil Belt, Venezuela.

<table>
<thead>
<tr>
<th>Orinoco extra-heavy oil</th>
<th>established oil resource initially in-place (billion barrels)</th>
<th>ultimate oil resource initially in-place (billion barrels)</th>
<th>initial established oil reserves (billion barrels)</th>
<th>ultimate oil reserves (billion barrels)</th>
<th>cumulative production (billion barrels)</th>
<th>remaining established oil reserves (billion barrels)</th>
<th>ultimate remaining oil reserves (billion barrels)</th>
<th>remaining developed reserves (billion barrels)</th>
</tr>
</thead>
<tbody>
<tr>
<td>source</td>
<td>PDVSA financial statement 2012</td>
<td>Layrisse &amp; Chacin (PDVSA) 1998</td>
<td>PDVSA financial statement 2012</td>
<td>increase in recovery factor from 20% to 22.5% to account for improved technology</td>
<td>end 2012. Mainly PDVSA or Ministry</td>
<td>end 2012. PDVSA financial statement 2012. Initial established reserves minus cumulative production</td>
<td>end 2012. ultimate reserves minus cumulative production</td>
<td>end 2012. PDVSA financial statement 2012</td>
</tr>
<tr>
<td>billion barrels</td>
<td>1338</td>
<td>1895</td>
<td>262.6</td>
<td>295.4</td>
<td>3.3</td>
<td>259.3</td>
<td>292.1</td>
<td>4.1</td>
</tr>
</tbody>
</table>
major projects developed to date is only 8%, but this is for recovery by cold primary production. Introduction of extensive horizontal drilling and thermal recovery methods should be sufficient to ensure an average 20% recovery. Modern heavy oil technology would further raise the mean estimate of recoverable extra-heavy oil to 513 Gb [49], which would make Venezuela the world’s top hydrocarbon liquid resource holder.

Geology

The Orinoco Oil Belt resources occur in the Lower Miocene Oficina Formation, especially the Morichal Member. The Morichal is a fluvial, intertidal and nearshore marine system comprising sandstones and intervening siltstones 60–90 m thick. Porosity of the relatively unconsolidated sand is in the 30–35% range, whereas permeability ranges from 700 to 20 000 millidarcies (mD).

The reservoir lies at depths of 350–700 m (1150–2300 feet), which is generally deeper than the Alberta oil sands. Combined with the higher average surface temperatures when compared with Alberta, this gives rise to reservoir temperatures of 48–55°C. At such temperatures, the oil remains fluid (1500–5500 cP) despite its low average gravity of 8.5° API. The oil is thought to have originated as a lighter oil in the Upper Cretaceous Querecual Formation, which migrated over long distances (150 km) and over long periods (from the Late Eocene onwards). Trapping occurs both by onlap of the sands onto basement and by self-sealing with extra-heavy oil. Although the reservoirs are shallow, there are no surface indications of oil. The main cause of the degradation to extra-heavy oil is thought to be biodegradation by microorganisms introduced by meteoric water influx. Water washing may have assisted in removing the lighter hydrocarbons.

Development

Although discovered in 1936, the Orinoco Oil Belt remained largely unexplored until an exploration campaign by PDVSA between 1978 and 1983. A number of experimental projects were carried out throughout the 1980s, and in 1990 Bitumenes del Orinoco (BITOR) commenced large-scale production of a fuel oil substitute called Orimulsion. Orimulsion was an emulsion consisting of 70% extra-heavy oil and 30% water. Production continued until end 2006.

During the 1990s, construction commenced on four combined cold production/upgrading projects to pipe diluted extra-heavy oil to upgraders for conversion to marketable crudes. The projects were managed by four incorporated joint ventures described in table 5. Between 2005 and 2007, there were a number of changes in the ownership structures.

Total extra-heavy oil production from all Orinoco operations in 2012 was about 860 000 b d⁻¹ out of total Venezuelan crude production of 2 050 000 b d⁻¹.

In June 2005, Venezuela decided to invite companies to quantify the in-place and recoverable resources in 27 further Orinoco blocks (other than those in table 5) and to submit plans for their development (the Magna Reserva Project). Of the estimated 262.6 Gb recoverable in the Orinoco Oil Belt, assuming a 20% recovery factor, 235.6 Gb lie in areas covered by the Magna Reserva Project. Since 2010, six development contracts have been signed for Magna Reserva blocks, which are planned to produce about 2.1 Mb d⁻¹ when in full production, scheduled for 2018. PDVSA holds a 60% interest in all of these contracts. In addition, PDVSA is itself developing one block. Combined production of all seven projects is forecast to reach 2.33 Mb d⁻¹ by 2021, but an independent analysis suggests 1.9 Mb d⁻¹ by 2025 is a more likely scenario [50], whereas the IEA has a more downbeat forecast of 1.3 Mb d⁻¹ in 2020 [24]. Early production from Magna Reserva blocks Junin 4, 5, 6 and 10 is scheduled for 2012, with Carabobo 1 set to follow in 2013.

(iii) Other countries

Relatively few countries have significant resources of extra-heavy oil other than Venezuela. The USA had an initial in-place extra-heavy oil resource more than 2.6 Gb, over 95% of it in California in fields that have already been exploited, frequently by thermal methods. Recoverable reserves are estimated at only 9% of original oil in-place and 90% of the recoverable reserve.
Table 5. Original and current ownership of Orinoco production/upgrading joint ventures.

<table>
<thead>
<tr>
<th>Original project name</th>
<th>Original company</th>
<th>Original ownership</th>
<th>Production onstream</th>
<th>Upgrader online</th>
<th>Current project/company</th>
<th>Current ownership</th>
<th>Original/current area</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hamaca</td>
<td>Petrolera Ameriven</td>
<td>PDVSA: 30%; Phillips: 40%; Texaco: 30%</td>
<td>October 2001</td>
<td>Q3-2003</td>
<td>PetroPlar</td>
<td>PDVSA: 70%; Chevron: 30%</td>
<td></td>
</tr>
<tr>
<td>Petrozuata</td>
<td>Petrolera Zuata</td>
<td>PDVSA: 49.9%; Conoco: 50.1%</td>
<td>August 1998</td>
<td>February 2001</td>
<td>PetroAnzoátegui</td>
<td>PDVSA: 100%</td>
<td>Zuata/Junin</td>
</tr>
</tbody>
</table>
has already been produced. More resources occur in Cuba, Peru and Mexico. In recent years, offshore discoveries in Brazil’s Campos Basin have included oils whose API gravity is believed to approach that of extra-heavy oil. In the Middle East, Iran, Iraq and Saudi Arabia each have a few fields containing some extra-heavy reservoirs. In Europe, Albania’s Patos–Marinza field, Italy’s offshore Gela field and the UK’s offshore Tudor Rose field all have significant resources of extra-heavy oil. The greatest resource of extra-heavy oil in the eastern hemisphere is thought to lie in China, especially in the Liahe area of the Bohai Gulf Basin.

(iv) Extraction and production

Current production in the Orinoco Oil Belt is ‘cold’, i.e. without thermal stimulation. Cold production typically has recoveries of less than 10% of the extra-heavy oil in-place. Extended-reach horizontal wells are used to maximize production. In some cases, these use naphtha diluent injection to help improve recovery.

It is expected that some of the thermal techniques that have been developed for in situ bitumen production in Alberta will be used in Venezuela. The PetroCedeño operation planned to trial three different steam-based thermal techniques in 2011 in the hope of doubling per-well recovery, namely SAGD, horizontal alternate steam drive and steam drive. In 2013, a polymer injection trial is planned in the deposit. In PetroMonagas, the use of SAGD has been simulated by reservoir modelling and is potentially applicable.

(v) Costs and economic issues

PDVSA has a minimum 60% financial interest in all heavy oil projects, which brings high returns to the nation when oil prices are high, but when prices fall it either diverts income away from national social projects or from project investment. Low prices also reduce the availability of market finance to external investors, so terms need to be made attractive. The perceived level of political risk and consequent lack of fiscal stability is a major issue for private companies, which may explain why most participants in the Magna Reserva Project are State-controlled companies, for whom security of future supply is more important than shareholder returns.

(vi) Environmental issues

No specific environmental issues have been reported in the Orinoco Oil Belt other than the existence of a dense forest of Caribbean pine at the eastern (Carabobo) end of the oil belt that has in the past required deviated drilling from pads to minimize impact on this unique environment.

5. Unconventional natural gas

Unconventional natural gas can exist in different states. Shale gas has a mixed system, with some gas existing as free gas and some gas adsorbed on kerogen and clay mineral particles. In coal seam gas reservoirs, most gas exists adsorbed on coal surfaces, with a lesser amount occurring as free gas. In tight gas, the gas exists as free gas, contained within the porosity of the reservoir rock (sandstone, limestone or chalk).

The gas in natural gas hydrates forms a clathrate, a white ice-like solid in which cages of water molecules surround gas molecules. Gas hydrates can occur only in polar or high-altitude permafrost regions, or in oceanic sediments or deep inland seas where the water temperature is close to 0°C and the water depth exceeds 300 m. Because no commercial production method has been established for oceanic hydrates, and production from permafrost hydrates is negligible, gas hydrates are not discussed further. They should not be disregarded, however, because of their potential for significant environmental degradation and as geohazards. As methane is a potent GHG, rising temperatures in Arctic regions create the risk of major release of methane from permafrost hydrate deposits, resulting in further warming.

Some commentators have suggested that reservoirs in which gas occurs only as free gas should not be termed unconventional, thus excluding tight gas. One suggestion is that only reservoirs
that are also the source rock, and in which at least some gas is adsorbed on the source organic matter, should be termed unconventional gas reservoirs [51]. There is some logic to this, as the production technology of progressively tighter reservoirs has developed steadily over time, thereby making the boundary between conventional and unconventional hard to define. But tight reservoirs, shale reservoirs and coal seam reservoirs share a common feature in that the maximum micropore diameter through which gas must flow to the well is of the order of 1 µm [52]. Consequently, true tight gas reservoirs can only be developed by using similar technology to that for shale gas reservoirs and, to a lesser extent, coal seam gas reservoirs.

Although global estimates of in-place and recoverable unconventional gas are very approximate, recoverable resources are probably greater than those of unconventional liquids (figure 5). This estimate of remaining recoverable unconventional gas is conservative compared with other commentators and broadly assumes a 10% recovery factor for each unconventional gas type. As discussed below, other estimates (table 7) are considerably higher.

Because coal seams and organic-rich shale within the gas window have a widespread distribution, the distribution of potential unconventional gas resources is geographically widespread. Shale gas, in particular, can be expected almost anywhere that a conventional shale source rock is sufficiently organic-rich, sufficiently thick and within the gas window.

Unconventional natural gas is already an established and growing source of natural gas production. In 2012, global unconventional liquids production averaged some 4.6 Mb d⁻¹ or 5.4% of all liquids production from fossil fuels. By contrast, worldwide unconventional natural gas production in 2011 was some 50.5 billion cubic feet per day (bcfd), 15.5% of the total world production of 325 bcfd. This estimate is a minimum, as most countries do not differentiate between conventional and unconventional gas production. In 2011, over 68% of all gas production in the USA came from unconventional sources (figure 3).

(a) Global resources and major deposits

With the possible exception of coal seam gas, no reliable estimates of regional unconventional natural gas resources exist outside North America. Frequently quoted and apparently modern

![Figure 5. Estimated ultimate recoverable world liquid and gas resources (after Chew [53]). (Online version in colour.)](http://rsta.royalsocietypublishing.org/)
and authoritative sources of estimates [54–56] ultimately point back to Rogner [57], who in turn relied heavily on the late-1970s estimates of Kuuskraa & Meyers [58].

The methods used by Rogner [57] and Kuuskraa & Meyers [58] are subjective and potentially unreliable. Rogner states: ‘In summary, the data in the following tables have to be taken with a large grain of salt. This is particularly the case for the regional distribution which in many cases is highly speculative’ (table 6).

Even today, estimates of in-place resources for the world’s most highly explored region (North America) show considerable variation and often a significant difference from those of Rogner. In hindsight, Rogner’s estimate of in-place tight gas, in particular, appears to be conservative. In-place tight gas in North America, for instance, is currently believed to be some 8000 trillion cubic feet (Tcf), six times greater than Rogner’s estimate of 1375 Tcf.

Estimates of recoverable resources also show considerable uncertainty. For US shale gas, for which tens of thousands of wells have been drilled and where production in 2010 reached almost 5 Tcf, the EIA estimates 827 Tcf of unproved technically recoverable resource but considers that the potential range is 423 Tcf to 1230 Tcf [60]. Estimates for the rest of the world, where there is as yet no shale gas production and the wells drilled number in tens, should therefore be treated with Rogner’s ‘large grain of salt’.

Three organizations or companies have recently published estimates for some of the world’s recoverable unconventional natural gas resources (table 7). The estimates vary substantially for all

### Table 6. Rogner’s estimates [57] of world in-place unconventional natural gas resources by region and type (from [59]).

<table>
<thead>
<tr>
<th>Region</th>
<th>Coal Seam</th>
<th>Tight</th>
<th>Shale</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>North America</td>
<td>3000</td>
<td>1375</td>
<td>3850</td>
<td>8225</td>
</tr>
<tr>
<td>Latin America</td>
<td>50</td>
<td>1300</td>
<td>2100</td>
<td>3450</td>
</tr>
<tr>
<td>Europe</td>
<td>275</td>
<td>425</td>
<td>550</td>
<td>1250</td>
</tr>
<tr>
<td>C.I.S.</td>
<td>3950</td>
<td>900</td>
<td>625</td>
<td>5475</td>
</tr>
<tr>
<td>Middle East/Saharan Africa</td>
<td>0</td>
<td>825</td>
<td>2550</td>
<td>3375</td>
</tr>
<tr>
<td>Sub-Saharan Africa</td>
<td>50</td>
<td>775</td>
<td>275</td>
<td>1100</td>
</tr>
<tr>
<td>Asia-Pacific</td>
<td>1725</td>
<td>1800</td>
<td>6150</td>
<td>9675</td>
</tr>
<tr>
<td>Total</td>
<td>9050</td>
<td>7400</td>
<td>16100</td>
<td>32550</td>
</tr>
</tbody>
</table>

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<td>275</td>
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<td>550</td>
<td>1250</td>
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<td>Middle East/Saharan Africa</td>
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<tr>
<td>Total</td>
<td>9050</td>
<td>7400</td>
<td>16100</td>
<td>32550</td>
</tr>
</tbody>
</table>

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Three organizations or companies have recently published estimates for some of the world’s recoverable unconventional natural gas resources (table 7). The estimates vary substantially for all
three types of unconventional natural gas, and caution should be used when basing any analysis upon them. The following paragraphs provide observations upon these estimates.

(i) Advanced Resources International

The Advanced Resources International (ARI) shale gas study was commissioned by the US Energy Information Administration (EIA) and covers 32 countries [60]. Some areas with significant potential such as Russia and the Middle East were excluded, because their large remaining conventional gas resources mean that shale gas resources are unlikely to be developed soon. The methodology quantifies the volume of shale basins, measures their organic content and thermal maturity, calculates the volume (and probability) of gas generation, and estimates the technically recoverable volume. Separately, ARI has estimated world in-place resources of coal seam gas to be in the range 3540–7630 Tcf with a recoverable resource of 830 Tcf, substantially less than estimated by the other two organizations.

Much of the detailed information required to make accurate assessments is simply not available in many areas, and so the assessments are still relatively speculative. Three examples illustrate this. The report estimates a technically recoverable resource of 41 Tcf for Sweden’s Alum Shale, which Shell’s recent three wells found to contain little gas, which it was not possible to produce. The Midland Valley of Scotland, where Europe’s first certification of recoverable shale gas resources has taken place, is considered by the report to be non-prospective. In the Polish sector of the Polish–Ukrainian Foredeep, the report indicates risked recoverable reserves of 187 Tcf, whereas the USGS Energy Resources Program estimates it to be 1.35 Tcf. With such disparities, today’s estimates for undrilled or virtually undrilled provinces are effectively meaningless.

(ii) International Energy Agency

The IEA’s 2009 estimates were obtained by taking Rogner’s 1996 in-place estimates [57] and applying a 40% recovery factor to each. The IEA’s 2011 estimates still use 40% of Rogner’s in-place estimate for tight gas, but have increased coal seam gas by 15% (500 Tcf) and upgraded the shale gas estimate on the strength of the EIA/ARI report [60]. The shale gas value is higher than that of EIA/ARI, presumably to take account of countries not covered by the report.

(iii) Total S.A.

French company Total S.A. is the only major international company to have published such estimates. In 2007, Total estimated the global in-place tight gas resource to be 11 000–18 000 Tcf, with 700–1750 Tcf recoverable and a preferred value of 1600 Tcf recoverable, of which 45% occurred in the USA and Canada [45]. By 2011, Total had reduced this estimate to some 1350 Tcf, 55% less than that of the IEA. Based on their 2007 estimate of in-place tight gas resources, this implies a global average recovery factor of around 10%.

Total’s 2011 recoverable coal seam gas estimate of approximately 1800 Tcf is 57% lower than that of the IEA but more than twice that of ARI. Given that reported in-place resources of coal seam gas from around the world sum up to around 7000 Tcf, Total’s estimates of the recoverable fraction may be optimistic. For shale gas, in 2011, Total estimated that the global in-place potential exceeded 20 000 Tcf. Their recoverable estimate of 4350 Tcf therefore implies a global average recovery factor of some 20% and is much lower than that of the IEA or the ARI.

Total’s estimate of 7500 Tcf of ultimate recoverable unconventional gas is identical to IHS-CERA’s end 2009 estimate of remaining recoverable discovered conventional gas [53], although considerable resources of conventional natural gas may remain to be discovered, especially in Arctic regions. BP estimated proved natural gas reserves (including unconventional gas reserves) to be 6614 Tcf at end 2012 [61].

In a review of estimates of unconventional gas resources, the UK Energy Research Centre also highlighted the uncertainty that surrounds such estimates, especially those of shale gas. They
noted ‘the very high level of uncertainty in these estimates, the inadequate treatment of this uncertainty by the majority of studies, the difficulties in comparing and combining estimates from different studies, and the limitations of currently available estimation methodologies’ [62].

(b) Shale gas

Shale gas occurs in a self-contained petroleum system where the generated gas remains trapped in the source rock. A significant portion of the gas is adsorbed on clay minerals and organic matter, whereas free gas occupies any pore voids. Free gas will produce immediately while adsorbed gas is only desorbed as pressure declines. It is therefore important in shale gas prospect evaluation to know the relative amounts of free and adsorbed gas, because initial production rates will be heavily influenced by the free gas component.

Thermogenic shale gas may form directly from thermally mature kerogen or from the thermal cracking of previously generated oil. Most commercial shale gas deposits are considered to have such an origin. Biogenic shale gas is found in thermally immature shale in which methane has been generated by microbial action. The Antrim Shale in Michigan is the most prolific biogenic shale gas play known, with cumulative production more than 3 Tcf.

(i) Global resource distribution

Most shale gas production currently occurs in the USA. The world’s first well drilled with the intention of producing hydrocarbons was a shale gas well drilled in 1825 at Fredonia, New York (Fredonia Censor, 31 August 1825). It produced gas from Devonian black shale at a depth of 27 feet, used for lighting. Shale gas has been produced from Devonian shale of the Appalachian Basin ever since. Despite this long history, only recent technological advances are making full commercialization possible. Estimates of the resource base and recovery factors are still at an early stage. Shale gas has resulted in a collapse in US natural gas prices, with the average price since the beginning of 2009 being less than half that of the preceding 6 years.

Table 8 reports resource estimates for the five largest US shale gas plays, ranked by end 2011 proved reserves. It illustrates the disparity and uncertainty even in areas that have been extensively explored and developed. The estimate of the US ultimate recoverable resource is continuing to increase as new plays develop and recovery technology improves.

(c) Coal seam gas

Coal seam gas, also known as coalbed methane, coalbed gas and natural gas from coal, is a methane-rich gas that occurs in coal seams. As in the case of shale gas, it is a self-contained source–reservoir petroleum system, but in this case most (approx. 90%) of the gas is adsorbed on coal surfaces, with the remainder occurring dissolved in formation water or as free gas in fractures and micropores. It is the adsorbed gas that makes these relatively thin coal seam reservoirs an attractive exploration prospect. A coal can store six to seven times as much gas as the equivalent volume of rock in a conventional reservoir.

Coal seam gas is a sweet gas, generally containing more than 90% methane (plus ethane, CO₂ and N₂), and requires little or no processing. This means that it can be used directly in power stations and public gas distribution systems, although it does have a low calorific value as a result of the lack of NGLs.

(i) Global resource distribution

Estimates of in-place coal seam gas resources are available for most countries with major coal resources, but even within a basin each coal field has unique gas properties, so recoverable resource estimates are highly speculative without previous production experience. Recoverable resources are also constrained by environmental regulations covering well spacing and water disposal.
Table 8. In-place and recoverable resource estimates for key US shale gas plays.

<table>
<thead>
<tr>
<th>Shale play</th>
<th>Series</th>
<th>Basin</th>
<th>State</th>
<th>Gas in-place</th>
<th>Unrisked gas in-place</th>
<th>Technically recoverable</th>
<th>Technically recoverable</th>
<th>Unproved recoverable</th>
<th>Technically recoverable</th>
<th>Proved reserves</th>
<th>Cumulative production</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barnett</td>
<td>L Carb</td>
<td>Fort Worth</td>
<td>TX</td>
<td>250</td>
<td>1150</td>
<td>26.2</td>
<td>107</td>
<td>40</td>
<td>32.6</td>
<td>3.2</td>
<td>10.8</td>
</tr>
<tr>
<td>Marcellus</td>
<td>M Dev</td>
<td>Appalachian</td>
<td>WV, OH; PA, NY</td>
<td>2100</td>
<td>350</td>
<td>34.2</td>
<td>60</td>
<td>200</td>
<td>140.6</td>
<td>31.9</td>
<td>2.0</td>
</tr>
<tr>
<td>Haynesville</td>
<td>U Jur</td>
<td>Gulf Coast</td>
<td>LA, TX</td>
<td>790</td>
<td>400</td>
<td>34.0</td>
<td>31</td>
<td>130</td>
<td>65.9</td>
<td>29.5</td>
<td>4.3</td>
</tr>
<tr>
<td>Fayetteville</td>
<td>L Carb</td>
<td>Arkoma</td>
<td>AR</td>
<td>320</td>
<td>309</td>
<td>26.0</td>
<td>58</td>
<td>50</td>
<td>13.2</td>
<td>14.8</td>
<td>2.6</td>
</tr>
<tr>
<td>Woodford</td>
<td>U Dev–</td>
<td>Arkoma–</td>
<td>OK</td>
<td>300</td>
<td>719</td>
<td>12.2</td>
<td>53</td>
<td>30</td>
<td>21.7</td>
<td>10.8</td>
<td>1.4</td>
</tr>
<tr>
<td></td>
<td>L Carb</td>
<td>Anadarko</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td></td>
<td></td>
<td></td>
<td>141.7</td>
<td>76</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td></td>
<td>3760</td>
<td>2928</td>
<td>274.3</td>
<td>385</td>
<td>450</td>
<td>481.8</td>
<td>131.6</td>
<td>27.8</td>
</tr>
</tbody>
</table>
Table 9 reports some national estimates of in-place and recoverable coal seam gas resources. Given that some significant countries are absent from this listing, 5500–7000 Tcf seems a likely range for the global in-place coal seam gas resource, of which some 700 Tcf is expected to be recoverable.

(d) Tight gas

Tight gas—also sometimes referred to as ‘deep gas’ and ‘basin-centred gas’—is not restricted to regionally pervasive resource play accumulations, but can also occur in conventional traps, not necessarily basin-centred and not necessarily deep.

In the basin-centred gas setting, tight gas pervades abnormally pressured low-permeability reservoirs in the central (generally deeper) part of basins. It is typically overpressured in subsiding basins and underpressured in uplifted and eroded basins. The presence of basin-centred gas implies that the expulsion and migration of gas from deep source rocks is more inefficient than generally perceived and that these reservoirs act as closed systems. The up-dip seal may be a gas/water transition zone, causing a reduction in relative permeability (a reversal of the normal circumstances where water underlies gas).

Tight gas reservoirs generally occur in sandstone or siltstone but rarely in carbonate rocks, and are defined by low permeability and porosity. The average matrix permeability is taken to be less
than 0.1 mD or less than 0.6 mD effective permeability to gas. Maximum porosity can be as great as 15%, though 10% porosity is more typical. Characteristically, large pores are not connected. Instead, the pore interconnectivity is limited by microporosity, with pore throats as small as 1 µm in diameter [52].

The best tight gas reservoirs are heterogeneous with ‘sweet spots’ of higher porosity–permeability that can be of either sedimentological or structural origin, where fracturing has occurred. In the USA, some of the most prolific tight gas plays comprise thick-stacked sandstones that can be fractured over the entire interval.

(i) Global resource distribution

Tight gas deposits are only defined by reservoir rock parameters, and even when these are known it is possible that only certain parts of an accumulation will be tight. Consequently, evaluation of the global distribution of tight gas accumulations is not possible, because the information required to establish ‘tightness’ is not in the public domain. Global estimates of production and resources are therefore speculative and an approximation. Total S.A. has tight gas interests on four continents outside North America, and is therefore better placed than most to estimate the global resource. Total S.A. (table 7) estimated the worldwide in-place tight gas resource to be in the range 11 000–18 000 Tcf with approximately 1350 Tcf recoverable.

6. Summary and outlook

Geologically unconventional ‘resource plays’ are attractive because of their large areal extent and consequent low exploration risk and long, stable production life.

In-place resources of unconventional hydrocarbon liquids (approx. 10 trillion barrels) exceed remaining in-place resources of conventional hydrocarbon liquids (approx. 7.5 trillion barrels), but have much lower average recovery factors. Their ultimate production volume is unlikely to match that of conventional oil and NGLs. Geographically, most occur in North America and Venezuela.

The bitumen resource of Canadian oil sands is the most highly developed unconventional liquid resource, with cumulative production of some 7.9 Gb. The ultimate recoverable resource could be as high as 315 Gb. Production today is 1.8 Mb d\(^{-1}\) and may reach 5 Mb d\(^{-1}\) by 2030. Although most recovery has so far come from mining, a variety of underground (\textit{in situ}) technologies have been developed in Canada that will have application around the world to bitumen, extra-heavy and heavy oil deposits.

The second major developed source of unconventional liquids is the extra-heavy oil accumulation of Venezuela’s Orinoco Oil Belt, where 3.3 Gb have so far been produced from an expected ultimate recoverable resource of 263 Gb. Production at present comes from four well-established projects, but new projects will raise the production rate from 0.85 Mb d\(^{-1}\) to some 2.3 Mb d\(^{-1}\) by 2021 if they proceed on schedule. There is substantial potential for additional development projects.

Oil production from tight self-sourcing reservoirs has grown dramatically in the past 5 years, especially in the USA. US tight oil production reached one million barrels of oil per day in 2012. Growth is forecast to continue as analogues are sought elsewhere and as production technology improves, but low recovery factors and per-well productivity, rapid decline rates per well and the tens of thousands of wells required mean that this source is unlikely to reach the production levels of oil sands or extra-heavy oil production. Unlike oil sands and extra-heavy oil, tight oil requires no processing other than conventional refining.

A key characteristic of all but the tight self-sourcing reservoirs is that their development is energy intensive and requires substantial capital investment and long lead times from investment decision to first production. This means that, while future production growth from unconventional oil sources will help ameliorate the natural decline in production from conventional oil fields, it seems unlikely to replace it completely.
Unconventional natural gas accumulations occur in a variety of host rocks and gas states (free, adsorbed or clathrates). Unconventional gas is more evenly distributed around the globe than unconventional oil, and therefore provides the prospect of security of supply for more countries. Ultimate recoverable unconventional natural gas resources are estimated at 675–1250 Gb oil equivalent, which is significantly greater than those of unconventional liquids. In 2011, unconventional gas accounted for a minimum of 15.5% of worldwide gas production, largely from North America, where conventional gas resources are becoming depleted. Elsewhere, there has been less focus on unconventional gas, partly because of abundant conventional resources, and partly because developing indigenous unconventional gas is often more expensive than importing conventional gas.

The eightfold growth in shale gas production over the past decade and the international interest that this has created suggest that a decade from now we may well see significant shale gas production outside North America. Environmental concerns over hydrofracturing may delay development but will probably prove to be insignificant because existing, largely standard, operating procedures already resolve the technical issues.

In the case of both shale gas and coal seam gas, the reservoir is also the source rock. Much of the gas is adsorbed, and desorbing it may take several months, so the local potential for coal seam gas can take some time to evaluate. The economics of coal seam gas production is such that it is likely to attract less interest internationally than shale gas except where it occurs in optimal conditions.

In tight gas accumulations, normally in sandstones or siltstones, the gas exists in a free state but connectivity between pores is severely reduced and permeability is very low (0.1 mD or less). Despite this, modern fracturing technology has resulted in the exploitation of tight reservoirs with great success. Because producers have gradually extended their capabilities into progressively tighter deposits over time, tight gas is the most extensively developed unconventional gas resource worldwide. The interest shown in ultra-tight deposits, however, indicates that production from tight accumulations will continue to rise in decades to come.

Collectively, unconventional oil and gas are having a significant impact on North American energy supply, with the knock-on effect being felt worldwide. US crude oil production in December 2012 exceeded 7 Mb d⁻¹, the highest level since December 1992, whereas crude imports in the same month fell to the lowest level since the mid-1990s. US natural dry gas production and gas consumption both reached record levels in 2012. Canadian oil sands production grew by a further 12% in 2012, but limited pipeline export capacity and the glut of tight oil in the US Midwest resulted in the so-called bitumen bubble. The gap between the price of non-upgraded bitumen and US benchmark West Texas Intermediate has recently widened to more than US$40 a barrel compared with a historical differential of less than US$20.

Consequent effects of the availability of low-cost indigenous unconventional gas included an increase in US coal exports to the rest of the world and increased competitiveness of the US petrochemical and manufacturing industries in global markets.

Substitution of coal by gas has led to a reduction in CO₂ emissions in the USA, and if unconventional gas can be developed elsewhere at relatively low cost, then this will have global environmental benefits. Substitution of oil by gas, accompanied by the development of unconventional liquid resources, should ensure that the peak of oil production takes the form of an undulating plateau rather than a rapid decline.

Acknowledgement. The author has declared that he has no competing interest.

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