Shale Gas: A Global Resource

Producing commercial quantities of natural gas from organic-rich shales was uncommon a decade ago. Success in the Barnett Shale of central Texas, USA, launched a new way of thinking about shale source rocks. The techniques used there were applied to other North American basins where conditions were favorable for coaxing natural gas from source rocks. Successful gas production from shales soon followed in numerous locations in the US and Canada, generating exploration interest on a global scale as companies now attempt to replicate that achievement.

Chuck Boyer
Pittsburgh, Pennsylvania, USA

Bill Clark
Oklahoma City, Oklahoma, USA

Valerie Jochen
College Station, Texas, USA

Rick Lewis
Dallas, Texas

Unconventional Resources

Organic-rich shale deposits with potential for hydrocarbon production are referred to as both unconventional reservoirs and resource plays. Unconventional gas reservoirs refer to low- to ultralow-permeability sediments that produce mainly dry gas. Reservoirs with permeability greater than 0.1 mD are considered conventional, and those with permeability below that cutoff are called unconventional, although there is no scientific basis for such a designation.

According to a more recent definition, unconventional gas reservoirs are those that can be produced neither at economic flow rates nor in economic volumes unless the well is stimulated by hydraulic fracture treatment or accessed by a horizontal wellbore, multilateral wellbores or some other technique to expose more of the reservoir to the wellbore. This definition includes formations composed of tight gas sands and carbonates, as well as resource plays such as coal and shale. The term resource play refers to sediments that act as both the reservoir and the source for hydrocarbons. Unlike conventional plays, resource plays cover a wide areal extent and are not typically confined to geologic structure.
Producing hydrocarbons from shale deposits is nothing new; the practice predates the modern oil industry. In 1821, decades before the first oil well was drilled, a commercial shale gas well was drilled in Fredonia, New York, USA. By the 1920s, the world’s most prolific natural gas production came from similar shale deposits in the nearby Appalachian basin. The methods used then for exploiting gas shales little resemble current practices. Operators drilled vertical wells that produced low flow rates. However, successful production of natural gas from the Appalachian basin proffered hope for those who later sought to tap the Barnett Shale and similar resource plays.

Development of the Barnett Shale traces its roots to 1981 when Mitchell Energy & Development Corporation drilled a well exclusively for the production of gas from shale. There was no instant gratification; 20 years of drilling and completion innovation, along with increases in commodity pricing, created the environment that brought the play commercial viability.

Hydraulic fracture stimulation was the first technology to unlock the gas trapped in shales. This practice creates permeability in rocks where very little exists naturally. Fracturing shale from vertical wells produced high initial production flow rates, followed by rapid falloff. Operators realized that more contact with the reservoir was needed to avoid these rapid declines. Thus, along with hydraulic fracturing, the second enabling technology—the ability to drill extended-reach horizontal wells—allowed contact with significantly more reservoir rock than is possible from vertical wellbores.

By applying these two technologies together, companies operating in the Barnett Shale proved that economic volumes of hydrocarbons could be liberated from the shale source rocks. Following this success, operators rushed to similar basins in search of shales that could become the “next Barnett.” Rocks that had been largely ignored by the E&P industry were suddenly the subject of great interest.

As evidence of the success in producing gas from shales, in 2008, the Barnett Shale became the largest gas-producing play or formation in the US, contributing 7% of all the natural gas produced in the contiguous 48 states for that year. Success in other gas shale plays followed. In March 2011, after just three years of development, the prolific Haynesville-Bossier Shale in Louisiana and east Texas produced 159.1 million m³/d (5.62 Bcf/d) of...
natural gas, eclipsing the Barnett Shale’s 152.9 million m³/d [5.40 Bcf/d]. In 2010, 137.9 billion m³ [4.87 Tcf] of dry gas was produced from the various US shale resource plays (above). This amounted to 23% of the annual production in the US. And the future for producing gas from shales appears bright. The Marcellus Shale in the Appalachian region of the eastern US, which is only now being explored and developed, has been projected to have the potential to surpass production of both the Barnett and Haynesville-Bossier shales. Exploration companies are now turning their focus to other regions with the hope of developing untapped shale resources.

**Global Perspectives**

E&P companies have routinely produced hydrocarbons from shale. For instance, operators in Brazil, Estonia, Germany and China produce oil from shales by retorting. However, as of 2011, there were no commercial operations producing gas from shales outside North America. That situation may change rapidly. Gas shale exploration is ongoing in South America, Africa, Australia, Europe and Asia. Around the world, E&P companies are acquiring and analyzing seismic data, drilling exploratory wells and evaluating formations for gas production capabilities. As assessment of global shale resources has continued, estimates for resource potential have gone up dramatically (next page, top). A recent study estimated that the global natural gas resource potential from shales was 25,300 Tcf [716 trillion m³]. However, in many cases, significant challenges lie in the path of development.

Unlike shale development in the US, where smaller operators were instrumental in much of the activity, European gas shale exploration and development tend to be dominated by large multinational energy companies and national oil companies. Companies with substantial acreage positions in Europe include ExxonMobil Corporation, Total S.A., ConocoPhillips Company and Marathon Company. With limited experience in shale exploration and development, these companies are partnering with companies that developed the North American gas shale industry. For example, Total has acquired a large stake in Chesapeake Energy Corporation, an active player in several US shale developments. ExxonMobil recently acquired XTO Energy Inc, a move seen by many energy analysts as an attempt to acquire expertise in developing shale resources.

Beyond the lack of existing technical experience, several other factors impede development of shale resources in Europe, Asia and South America. Sourcing large quantities of water for drilling and stimulation operations is a major concern, as is the limited availability of oilfield service equipment—primarily the type used for...
hydraulic fracturing. Also, there are potential land use issues in densely populated areas of western Europe. Whereas the mineral rights for much of the land in the US are controlled by landowners, this is not the case in other countries, where the state owns below-ground resources. The potential conflicts between surface owners and resource developers pose perhaps the most daunting challenge to development in Europe.

In the rush to develop, it is difficult to ignore nontechnical issues, which include geopolitics, public perception and a host of other concerns. Despite these factors, and because of the game-changing nature of gas shale plays in the US, global interest has heightened. A comprehensive report published by the US Energy Information Administration (EIA) in 2011 assessed 48 gas shale basins in 32 countries and reviewed the current state of shale development (below). Based on this report, the world appears poised for a shale gas revolution.

### Shale Gas Assessments

**United States**—Currently, the only commercial shale resource plays are located in North America, with the majority in the US. The Marcellus Shale in northeastern US is by far the largest play, with an estimated areal extent of 246,000 km² [95,000 mi²]. This is followed by the New Albany Shale at about half that size. Other

<table>
<thead>
<tr>
<th>Region</th>
<th>1997 Rogner Study, Tcf</th>
<th>2011 EIA Study, Tcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>North America</td>
<td>3,842</td>
<td>7,140</td>
</tr>
<tr>
<td>South America</td>
<td>2,117</td>
<td>4,599</td>
</tr>
<tr>
<td>Europe</td>
<td>549</td>
<td>2,587</td>
</tr>
<tr>
<td>Africa</td>
<td>1,548</td>
<td>3,962</td>
</tr>
<tr>
<td>Asia</td>
<td>3,528</td>
<td>5,661</td>
</tr>
<tr>
<td>Australia</td>
<td>2,313</td>
<td>1,381</td>
</tr>
<tr>
<td>Other</td>
<td>2,215</td>
<td>Not available</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>16,112</strong></td>
<td><strong>25,300</strong></td>
</tr>
</tbody>
</table>


^ Global shale gas resources. The US EIA studied 14 regions for shale gas potential. Vast land masses in Russia, the Middle East and Africa were not included in the report (gray shade). Reasons cited for not including these regions in the report were scarcity of exploration data or the presence of abundant reserves in conventional reservoirs, which make shale gas unattractive—for the present. (Adapted from Kuuskraa et al, reference 6.)
major gas shales in the US range from 13,000 to 30,000 km² [5,000 to 12,000 mi²], some of which have proved to be prolific producers (below).

Based on 2011 estimates, the production leaders with the highest combined daily rates are the Barnett and Haynesville-Bossier shales. Ranking by production, although a significant indicator, may be misleading because different plays have experienced varying levels of development. When US plays are ranked instead by estimates of original gas in place (GIP), the Marcellus Shale at 42.5 trillion m³ [1,500 Tcf] leads all others. Although the Marcellus Shale appears to have the greatest potential, operators in the region have only recently begun to explore and develop the play. Of the shales that are actively being produced today, the largest is the Haynesville-Bossier Shale with an estimated original GIP of 20.3 trillion m³ [717 Tcf]. The Barnett Shale comes next at 9.3 trillion m³ [327 Tcf]. But several shale resources are currently in production. Some of the more notable are the Fayetteville, Woodford, Antrim, Eagle Ford and New Albany shales.

Canada—Numerous basins in Canada have significant shale gas potential. The largest are located in western Canada and include the Horn River basin, Cordova embayment, the Laird basin, the Deep basin and the Colorado group. These five basins contain a combined estimate of 37.6 trillion m³ [1,326 Tcf] GIP, of which 10 trillion m³ [355 Tcf] is considered technically recoverable.

The target sediments in the Horn River, Cordova and Laird basins are of Devonian age, and the main formations of interest are the

![North America shale plays. (Adapted from Kuuskraa et al, reference 6.)](image-url)
Muskwa, Otter Park, Evie, Klua and lower Besa River shales. Several operators have been active in these areas with positive results. The Triassic-age Montney Shale and the Doig Phosphate are located in the Deep basin. As of July 2009, 234 horizontal wells had been drilled into the Montney Shale and were producing 10.7 million m$^3$/d [376 MMcf/d] of natural gas.\(^*\)

Eastern Canada has several potential shale plays, although they have not been as extensively studied as those in the west. Prospective areas include the Canadian portion of the upper Ordovician-age Utica Shale in the Appalachian fold belt, which straddles the border with the US and has an estimated 4.4 trillion m$^3$ [155 Tcf] of GIP, of which 877 billion m$^3$ [31 Tcf] is technically recoverable. Few wells have been drilled in the Utica formation, and gas has been recovered during testing but at low rates.

The lacustrine Horton Bluff Shale in the Windsor basin is much smaller, with 255 million m$^3$ [9 Tcf] of GIP, of which an estimated 56.6 billion m$^3$ [2 Tcf] is technically recoverable. Farther west, the Frederick Brook Shale in the Maritimes basin of New Brunswick is in preliminary stages of exploration and evaluation.

Mexico—Organic-rich and thermally mature Jurassic- and Cretaceous-age shales are found in Mexico. (For more information on characteristics of organic shales, see “Shale Gas Revolution,” page 40.) They are similar to productive gas shales of relative age in the US, such as the Eagle Ford, Haynesville-Bossier and Pearsall shales.\(^1\)

Potential shale resources are located in northeast and east-central Mexico, along the Gulf of Mexico basin. The shales targeted for exploration also served as the source rock for some of Mexico’s largest conventional reservoirs.

Although little gas shale exploration activity has been reported in the five basins in Mexico studied by the US EIA, there is an estimated 67 trillion m$^3$ [2,366 Tcf] of GIP, of which 19.3 trillion m$^3$ [681 Tcf] is judged to be technically recoverable.\(^2\) The five basins of interest for shale development are the Burgos (which includes the Eagle Ford and Tithonian shales), Sabinas (which includes the Eagle Ford and Tithonian La Casita shales), Tampico (Pimienta Shale), Tuxpan (Pimienta and Tamaulipas shales) and Veracruz (Maltrata Shale). Although there is considerable interest in developing shale reservoirs in Mexico, many of the organic-rich shales are structurally complex from overthrusting, or they are more than 5,000 m [16,400 ft] deep, which is too deep for development using current technology. The greatest potential targets are in the north—the Eagle Ford and Tithonian shales of the Burgos and Sabinas basins.

Across the Rio Grande River in south Texas, the Eagle Ford Shale has produced both gas and oil. Because this formation extends across the border into the Burgos and Sabinas basins of Mexico, successful production on the US side of the border holds promise for similar results on the Mexican side.

In its first exploratory shale gas well, Mexico’s national oil company Petróleos Mexicanos (Pemex) Exploration and Production recently reported a successful gas test from the Eagle Ford Shale in the Burgos basin. Production commenced in May of 2011 with a rate of approximately 84,000 m$^3$/d [3.0 MMcf/d]. Pemex plans to drill 20 additional wells in the near future to further evaluate the resource potential of the five listed basins.\(^3\)

**South America**—Several potential gas shale basins are located in South America (above). Argentina has, by far, the largest resource potential, with an estimated 77 trillion m$^3$ [2,732 Tcf] of GIP, of which 21.9 trillion m$^3$ [774 Tcf] is considered technically recoverable.\(^4\) Brazil follows with

---

\(^{11}\) Arthur et al, reference 11.


\(^{15}\) Kuuskraa et al, reference 6.


\(^{17}\) Kuuskraa et al, reference 6.
The Neuquén basin, in west-central Argentina, appears to have some of the greatest potential for gas shale development. The region is already a major oil and gas producer from conventional and tight sandstones. The middle Jurassic Los Molles Formation and the Early Cretaceous Vaca Muerta Formation contain organic-rich sediments. These two deepwater marine shales sourced most of the oil and gas fields in the Neuquén basin.

The Vaca Muerta Formation has some of the best characteristics for development with high average total organic carbon (TOC) levels (4.0%), moderate depth—2,440 m [8,000 ft]—and over-average total organic carbon (TOC) levels (4.0%), fields in the Neuquén basin. Organic-rich sediments. These two deepwater marine shales sourced most of the oil and gas fields in the Neuquén basin.

The Vaca Muerta Formation is more mature than the Vaca Muerta and is found at an average depth of 3,810 m [12,500 ft]. Although covering a larger geographic area, lower TOCs (1.5% average) in the Los Molles Formation provide less net GIP than in the Vaca Muerta Formation. However, there are richer sections in the Los Molles Formation with TOCs averaging 2% to 3%. Repsol YPF, S.A., recently began drilling, completing, fracturing stimulating and testing wells in the Neuquén basin and successfully completed an oil producer in the Vaca Muerta Formation.

Central Patagonia’s San Jorge basin accounts for 30% of Argentina’s conventional oil and gas production. The Late Jurassic and Early Cretaceous Aguada Bandera Shale was the predominant source rock for these accumulations. With good thermal maturity across most of the basin and middle to high TOCs, the Aguada Bandera Shale has potential for shale gas production. It is found at depths between 3,487 and 3,766 m [11,440 and 12,160 ft]. The lacustrine depositional environment of these sediments poses a potential risk for development because lacustrine shales are viewed as generally worse targets than marine shales.

Another lacustrine shale, the Early Cretaceous Pozo D-129 shale formation, is also located in the San Jorge basin. It is consistently 915 m [3,000 ft] thick in the central part of the basin, and early analysis of the sediments indicates moderate TOC values and good thermal maturity. The best prospects for gas shale developments are in the central and northern parts of the basin because of the oil-prone nature in the southern portions.

The Austral-Magallanes basin in southern Patagonia straddles the Argentina-Chile border. The Chile portion of the basin, Magallanes, accounts for essentially all of the country’s oil production. The main source rock for the basin is the lower Cretaceous lower Inoceramus Formation, which contains organic-rich shale deposits. This formation is approximately 200 m [655 ft] thick, found at depths of 2,000 to 3,000 m [6,562 to 9,842 ft] and has low to medium TOC values.

The Chaco-Paraná basin is immense, encompassing an area in excess of 1,294,994 km² [500,000 mi²]. The basin covers most of Paraguay and parts of Brazil, Uruguay, Argentina and Bolivia. It has not been extensively explored; there are fewer than 150 wells drilled across the entire basin. The Devonian-age Los Monos Formation contains several marine shale deposits. The most promising is the San Alfredo Shale, which is found as a thick, monotonous layer of black shale overlying a sandy unit. Although it can be as much as 3,658 m [12,000 ft] thick, only about 600 m [2,000 ft] are thought to have organic richness. The little information that is available indicates a shale matrix that has good characteristics for fracture stimulation.

Based on assumed thickness, thermal maturity and gas saturations, and using data from the few wells drilled across the basin, engineers have estimated a conservative 50 trillion m³ [2,083 Tcf] of GIP, with 14.8 trillion m³ [521 Tcf] technically recoverable.

Europe—Europe has many basins with shale gas prospects (next page). Because it appears to have some of the greatest potential, Poland is one of the most active countries for gas shale exploration in Europe. The Silurian-age Baltic and Lublin basins run north-central to southeast across the country and are bounded by the Trans-European fault zone. The Podlasie basin is located to the east of these two basins. The Lublin and Podlasie basins are similar to each other and are differentiated from the Baltic basin by geologic features and regional tectonic faulting. Estimated gas in place for these three basins is 22.4 trillion m³ [792 Tcf] GIP, of which 5.3 trillion m³ [187 Tcf] is considered technically recoverable. Although the Podlasie basin has some of the best reservoir properties, the Baltic basin is by far the largest in areal extent and total GIP.

A number of exploration companies are active in Poland, and the first shale exploration well was drilled in the Baltic basin in 2010. The vertical evaluation well was a joint venture between 3Legs Resources plc and ConocoPhillips Company. BNK Petroleum Inc has drilled and tested wells in the Baltic basin, targeting Silurian- and Ordovician-age formations.

With an estimated 20.4 trillion m³ [720 Tcf] of GIP and 5.1 trillion m³ [180 Tcf] recoverable, France closely follows Poland in estimated gas shale resources. These resources are located principally in the Paris basin and Southeast basin. The Paris basin contains two organic-rich shales, the Toarcian black shale formation and Permian-Carboniferous shales. Portions of the Toarcian shales are thermally immature and high in oil content, thus limiting their gas potential. The more mature Permian-Carboniferous shales—ranging in age from Pennsylvanian to Late Permian—are deeper and less explored than those in the northern Paris basin. Average shale thickness is around 350 m [1,150 ft] although at the basin’s eastern margin, thicknesses of more than 2,200 m [7,200 ft] can be found in isolated sections. Minimal data are available from well logs, so gas estimates are based on extrapolated assumptions.

Most of the exploration in the Paris basin has been directed at shale oil, rather than gas. Recently, however, E&P companies have been targeting the deeper resource plays lying in the gas window. The most promising shale formations in the Southeast basin are the upper Jurassic Terres Noires black shales and lower Jurassic Liassic black shales. The eastern portion of the Terres Noires Shale is in the gas window, while the western edges are still in the wet gas-oil window. Because it was once deeper but uplifted along its western margin, the Liassic shale is generally more thermally mature than the Terres Noires Shale. Although the resource potential of the Liassic shale is considered greater than that of the Terres Noires Shale, its higher clay content makes it more difficult to fracture stimulate.

Currently, there is a moratorium on research and drilling for shale oil and gas in France, pending environmental impact studies. Of even greater consequence is a government ban on all hydraulic fracturing in France, which was enacted in June of 2011. Shale gas extraction is not expressly prohibited, but without the ability to apply fracturing technology, commercial viability of resource plays is difficult to realize.
To the north of France, the North Sea–German basin extends along the North Sea from Belgium, across the Netherlands to Germany’s eastern border. Within this basin are a number of formations with shale gas potential, including the Posidonia (located in isolated portions of the Netherlands and Germany), the Wealden (Germany) and the Carboniferous Namurian (the Netherlands) shales.\(^{31}\)

Significant volumes of the Posidonia and Wealden shales are thermally immature and only isolated sections have gas potential. Potential is low in both these shales with estimates of 736 billion m\(^3\) [26 Tcf] of GIP and 198 billion m\(^3\) [7 Tcf] recoverable in the Posidonia Shale and 254 billion m\(^3\) [9 Tcf] of GIP and 56.6 billion m\(^3\) [2 Tcf] recoverable in the Wealden Shale. The deeper and very mature Carboniferous Namurian Shale contains an estimated 1.8 trillion m\(^3\) [64 Tcf] GIP with 453 billion m\(^3\) [16 Tcf] recoverable.\(^{32}\) Several companies are currently exploring in both Germany and the Netherlands.

Farther north, the Alum Shale extends through Norway, Sweden and Denmark. The areas that are in the gas window offer promise for production; however, data are sparse. Based on available data, the estimated GIP is 16.7 trillion m\(^3\) [589 Tcf] with 4.2 trillion m\(^3\) [147 Tcf] considered technically recoverable.\(^{20}\)

The Pannonian-Transylvanian basin covers most of Hungary, Romania and Slovakia. Marine sediments deposited in this basin during the Oligocene are believed to be the source for most of Hungary’s conventional hydrocarbons. Although the shales have been exposed to a very high geothermal gradient, which has accelerated maturation of the organic material, the clay-rich rocks are of poor quality for production of shale gas. Exploration is in the early speculative stage; some initial testing has been discouraging.

\(^{19}\) TOC governs the resource potential of shale. Exploration targets typically have TOC values in the range of 2% to 10%.


\(^{22}\) Kuuskraa et al, reference 6.

\(^{23}\) Kuuskraa et al, reference 6.

\(^{24}\) Kuuskraa et al, reference 6.


\(^{26}\) Kuuskraa et al, reference 6.


\(^{28}\) Kuusskraa et al, reference 6.


\(^{31}\) Kuuskraa et al, reference 6.

\(^{32}\) Kuuskraa et al, reference 6.
The United Kingdom and Ireland are two additional areas for shale exploration. The United Kingdom has two major petroleum horizons—the Carboniferous northern petroleum system and the Mesozoic southern petroleum system. The two systems contain several basins with similar depositional and tectonic history. Government action to restrict shale exploration activities was reversed in May 2011 and there has recently been an increase in exploration drilling in both systems.

Petroleum exploration has taken place in the northern petroleum system for more than 100 years, and the Bowland Shale in the Cheshire basin of this region holds a high potential for development. Additional data are needed to fully evaluate the resource, especially in the western regions. Current estimates of GIP are on the order of 2.7 trillion m³ [95 Tcf], of which 538 billion m³ [19 Tcf] is technically recoverable. Recently, Cuadrilla Resources Ltd announced the discovery of 5.7 trillion m³ [200 Tcf] of shale gas in the Bowland Shale, which far exceeds the published estimates for the region.

The southern petroleum system has been explored since the 1920s, although until the discovery of the Wytch Farm field in 1973, there were few notable finds. The Liassic shale source rock has limited gas potential. It is deep—averaging 4,114 m [13,500 ft]—but lacks thermal maturity. Recoverable resource potential is only about 28.3 billion m³ [1 Tcf]. Celtique Energie Petroleum Ltd holds licenses in the Liassic shale of the Weald basin. This shale is thought to contain commercial quantities of wet gas, condensate and oil.

Numerous other shale deposits in basins across Europe may offer the potential for exploration and development. Most have not been widely explored or data have not been released to the public to evaluate their full potential.

Africa—Africa has several shale basins that are considered potential resource plays. Because of the presence of untapped conventional resources, there have been few reports of gas shale exploration activity (above). The notable exception to this is South Africa, where major and independent E&P companies have been actively pursuing shale gas production.
The Karoo basin in central and southern South Africa covers nearly two-thirds of the country. The Permian-age Ecca shale group contains significant volumes of gas, estimated at 51.9 trillion m³ [1.834 Tcf] of GIP, of which 13.7 trillion m³ [485 Tcf] is technically recoverable. The shales found in this basin are characterized as highly organically rich, thermally mature and in the dry gas window.

Several organic-rich shales are located in basins in northern Africa—from the Western Sahara and Morocco, across Algeria, Tunisia and Libya—but most exploration companies are concentrating on discovering and developing conventional reservoirs in these regions. However, unlike Algeria, Tunisia and Libya, Morocco has few natural gas reserves and depends heavily on imports to meet its internal consumption needs. For this reason, exploration activity in shale deposits is ongoing there.

The Tindouf basin (stretching across Morocco, Western Sahara, Mauritania and western Algeria), and to a lesser extent, the Tadla basin (in central Morocco), are targets of exploration and possible development as shale resource plays. These Silurian-age shale deposits contain an estimated 7.5 trillion m³ [266 Tcf] of GIP with about 1.5 trillion m³ [53 Tcf] technically recoverable. Exploration activity in Morocco, including seismic acquisition and exploratory drilling, recently began but is still in the early stages. San Leon Energy plc has expressed interest in shale gas, but at present is pursuing oil shale prospects in western Morocco.

Except as noted above and along the west coast of Africa, where E&P companies continue to find, produce and develop conventional resources, much of the remainder of Africa remains unexplored. The dearth of existing information, along with a lack of drilling and exploration resources, provides for a poor environment for gas shale development at present.

China—Many organic-rich shales with promise as resource plays have been identified in China (right). With an estimated 144.4 trillion m³ [5,101 Tcf] of GIP and 36.1 trillion m³ [1,275 Tcf] of technically recoverable gas, the potential is comparable to that of North America. There are two large sedimentary basins of interest—the Sichuan basin in the south and the Tarim basin in the west. Containing thick, organic-rich shale deposits, these basins cover large expanses and have good reservoir characteristics for development.

Thermally mature marine shales of lower Cambrian age (Qionghu Fm) and lower Silurian age (Longmaxi Fm) are found in the Sichuan basin. Exploration companies have expressed considerable interest in these formations because of gas shows in exploration wells. Their low clay content is also an advantage, making them potentially good candidates for fracture stimulation. There is, however, a large degree of structural complexity with extensive folding and faulting, which introduces risk for future development.

Operators are currently evaluating and testing in the Sichuan basin, although no commercial production has been confirmed. However, in 2010, China Petroleum and Chemical Corporation (Sinopec) reportedly produced commercial quantities of gas from tests in two different parts of the Sichuan basin—the Yuanba district in the northeast and the Fuling district in the southeast.

The Tarim basin in western China is one of the world’s largest frontier exploration basins. The shales of interest are of Cambrian and Ordovician age and served as the source rock for the 795 million m³ [5 billion bbl] of oil equivalent hydrocarbons in conventional carbonate reservoirs of the region. However, the arid conditions in the region—it lies beneath the Taklimakan Desert—mean souring water for fracturing will be difficult.

The Cambrian-age shales in the Manjiaer and Awati depressions are more than 1 km [3,280 ft] thick, and both deposits are in the dry-gas window. The excessive depth of these deposits limits the net footage of accessible organic-rich shale, but the high quality of the resource—low clay content, dry gas, moderate TOC and good porosity—makes them prime targets for exploration and evaluation.

---

Resource potentials for the Ordovician-age shales in the Manjiaer depression are even greater than for the Cambrian shales, with a net thickness of 1,600 m [5,250 ft] of organic-rich deposits. The Ordovician-age organic-rich shales in the Awati depression are around 400 m [1,300 ft] thick. Unfortunately, much of the resource in both of these formations is too deep for shale development using currently available technology. Shale exploration and evaluation activity have not been reported for the Tarim basin.

There are five other sedimentary basins in China but they are nonmarine and lack thermal maturity, although this has not prevented exploration and evaluation of their potential. Based on early results, the five basins appear to be nonprospective for shale gas, although data continue to be acquired and assessed.

India and Pakistan—Several basins in India contain organic-rich shales, although only four are viewed as having priority for exploration; Pakistan has one basin with potential (below). Other basins either lack thermal maturity or the data are too limited to perform a thorough evaluation. The five basins in these countries are the Cambay basin in western India, the Krishna-Godavari basin along the east coast of India, the Cauvery basin in southern India, the Damodar Valley basin in northeast India and the Southern Indus basin in southeast Pakistan. The five basins have a combined GIP estimate of 14 trillion m³ [496 Tcf], of which 3.2 trillion m³ [114 Tcf] is considered technically recoverable. Because of tectonic activity, basins in India and Pakistan are geologically complex.

The Kommugudem Shale in India’s Krishna-Godavari basin appears to have the greatest potential for production, followed by the Cambay Shale in the Cambay basin. Analysis of the Barren Measure Shale in the Damodar Valley ranks it as having the lowest potential of the four in India.

Exploration is ongoing in India with some reported success. Although analysis indicated marginal potential for commercial production in the Permian-age Barren Measure Shale in the Damodar Valley basin, it was the site of the first shale gas well drilled in India. The 2,000 m [6,562 ft] deep RNSG-1 well, drilled by Oil and National Gas Corporation (ONGC) Ltd, lays claim to being one of the first wells outside the US and Canada to produce gas from shale in commercial quantities. Additional exploratory and evaluation wells are planned for this basin.

Two organic-rich shales in the Southern Indus basin of Pakistan are the Sembar and the Ranikot formations. No public data on gas shale exploration or development for these formations are available at present. Estimates based on data previously acquired are for a combined 5.8 trillion m³ [206 Tcf] of GIP, of which 1.4 trillion m³ [51 Tcf] is technically recoverable.

Australia—Operators in Australia have a long history of developing unconventional reservoirs, which include tight gas and coalbed methane (CBM). Experience with CBM should be an asset in developing gas shale resources because the equipment and techniques used to develop shales are similar. However, the four main basins with shale gas potential are not located in the same regions as the CBM fields. The main basins being considered for development are the Canning, Cooper (location of Australia’s main onshore conventional production), Perth and Maryborough basins (next page). These basins hold an estimated 39.1 trillion m³ [1,381 Tcf] of GIP, of which 11.2 trillion m³ [396 Tcf] is technically recoverable.

The Ordovician-age Goldwyer Formation of the Canning basin has, by far, the greatest estimated recoverable resource and covers the largest geographical area in Australia. This region, however, is scarcely explored and currently lacks infrastructure for development. There is conventional hydrocarbon production in the region, although it is fairly recent; the first commercial oil discovery in this basin was made in 1981. The estimated recoverable gas is 6.5 trillion m³ [229 Tcf]; production awaits further exploration and analysis because only 60 wells have penetrated the resource.
As Australia’s main onshore gas supply, the Cooper basin produces about 14 million m³/d [0.5 Bcf/d] of natural gas from conventional and low-permeability reservoirs. The low-permeability, tight gas reservoirs are usually hydraulically fractured for production. Because of this, the Cooper basin has personnel with expertise and hydraulic fracturing equipment for developing shale resources.

The Permian-age Roseneath and Murteree shales of the Cooper basin appear favorable for development. They vary from about 50 to 100 m [165 to 330 ft] in thickness. A third formation in the basin, the Epsilon, is primarily a mixture of sandstone with carbonaceous shale and coal. The three targets are often viewed in combination and referred to as the REM formations.

Although their lacustrine origin and Type III kerogen source material are not typically the target of gas shale development, the REM formations have some positive attributes. Their low clay content results in rocks that can be more easily hydraulically fractured. In addition, an extremely high geothermal gradient—1.4°C/30 m [2.55°F/100 ft] in general, and up to 1.9°C/30 m [3.42°F/100 ft] in some parts—accelerated maturation of the source rock.

Although operators are still in the early stages of exploration, they are actively evaluating and testing in the Cooper basin. At least one exploration well has been drilled in the basin and an E&P company is analyzing the core for gas content and mechanical properties. Santos Energy Ltd and Beach Energy Ltd are two of the most active companies in gas shale exploration there.

The Perth basin is relatively small. The onshore portion of the basin has marine sediments with production potential, although much of the interval of interest is too deep for gas shale development. Formations in the northern extent of the Dandaragan trough, a large syncline of Silurian to Cretaceous age, contain potential resource rock. With high geothermal gradients and moderate to high TOCs, younger marine sediments, such as the Permian-age Carynginia and Kockatea shales, offer promise as well.

The Maryborough basin is on the east coast of Australia. There is no conventional hydrocarbon production in the region and little data for evaluating its potential. With data from only five exploration wells, more information is needed to fully characterize the shale potential. However, the Cretaceous Maryborough Formation, a thick marine deposit, does show promise. Recent estimates suggest a possible 651 billion m³ [23 Tcf] of technically recoverable gas with the possibility of adding to the estimate when the unexplored and poorly understood southern half of the basin is included in the evaluation.

Other exploration activities are taking place throughout the world. Some regions, such as the Middle East and Russia, have abundant gas shale potential, but easy access to conventional reservoirs precludes serious development efforts of shale. Energy-hungry and often resource-poor countries constitute the majority of the ongoing exploration activity.

Moving Forward

Energy resources are the lifeblood of modern economies. Twenty years ago, dire warnings were issued in the US that natural gas supplies were dwindling and alternate sources of supplies were needed—quickly. An aggressive program was recommended for importing LNG from countries with accessible supplies. Today, the situation is remarkably different. The US has an abundance of natural gas and the long-term supply is more secure than ever because operators have learned to tap natural gas from unconventional resource plays—primarily shale, but also CBM. Operators in many regions of the world, having observed the success in North America, are moving to catch up.

At one time, drilling and reservoir engineers may have considered shales nuisances to deal with in the search of reservoir quality rocks, and the thought of commercial production of natural gas from shale deposits was simply not realistic. But the oil and gas industry continues to develop new techniques and create ways to access hydrocarbons. As the global revolution in gas shale development gains momentum, exploration companies have only just begun to uncover what organic shales have to offer.

—TS