TIGHT GAS SANDS[1]

F. J. Hein[2] and C. D. Jenkins[3]

Introduction

The U.S. Energy Information Administration (EIA) estimates that about 310 Tcf (8.8 trillion cubic meters) of technically recoverable tight gas exists within the United States, with worldwide estimates of > 7,000 to > 30,000 Tcf (210 – 850 trillion cubic meters) of gas in tight sands. The fraction of this energy resource that can be produced depends upon the applicability of new and enhanced technologies (such as 3-D seismic, microseismic, horizontal drilling along with stimulation and porosity/permeability enhancement by multi-stage hydraulic fracturing), economics (well completion and drilling costs and gas prices), and environmental concerns (impacts on water resources, remediation, GHG emissions). At present, natural gas production from tight sandstones (those with permeabilities < 0.1 millidarcies) is currently about 6 trillion cubic feet (Tcf) (170 billion cubic meters) per year in the United States, comprising nearly 25% of its total annual gas production.

In light of the definitions of tight gas sands, under present market conditions, it is clear that tight gas sands must also include a high-liquids component to become profitable – that is, many of the successful plays may be commingled with 'fringe' deposits from otherwise conventional oil and gas plays, including liquids-rich gas (and/or condensate) from organic-rich, fine-grained, mixed-bed lithologies (siltstone, marl, mudstone, very fine sandstone, and/or carbonate along with the 'tight gas sands'). It is also likely that as development of these plays continue to evolve by multi-stage horizontal drilling, with hydraulic fracturing, that there will be a continuum from fringe conventional oil and gas plays → unconventional tight gas sands → unconventional tight shale gas, and that the present distinctions between these various hydrocarbon commodities will become less clear.

Tight gas sand plays are being tested and developed in many countries outside of the U.S.A., including Canada (Western Canada Sedimentary and Maritimes Basins), Australia (Perth, Gippsland, and Copper Basins), China (Ordos and Hami Basins), and the Ukraine (Donetsk-Dnepr Basin). In Canada, tight gas sand plays have been pursued (and produced actively) since about 2005, with the plays ranging from Triassic to Late Cretaceous in age, and hosted within a large range of sedimentary environments from deep-water distal turbidites (similar to the Lewis Shale of Texas) to alluvial fan/braid-plain conglomerates. This broad suite of tight gas sandstone plays were initially exploited using techniques imported from the U.S.A.; however, since the initial drilling and completion work was done, it has been found that many of these plays in the Western Canada Sedimentary Basin need completion and drilling strategies that are tailored to the unique geology of that area.

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[1] Modified from Jenkins, C.D., in press, Tight Gas Sands, in: Unconventional Energy Resources: 2011 Review, Natural Resources Research, p. 12-16.

[2] Energy Resources Conservation Board, Calgary, AB, T2P 0R4, Canada; Chair, EMD Gas (Tight) Sands Committee

[3] DeGolyer and MacNaughton, Dallas,TX 75244, USA; Past-Chair, EMD Gas (Tight) Sands Committee

To date, those tight gas sand projects with large production histories include multiple projects in the United States; with the more development plays in the other countries. Those plays with long production histories may provide insights and analogs for the appraisal and development of the new emerging areas; however, in the case of these types of plays many are 'like snowflakes,' where no two are alike. In the following sections four of the more developed plays are discussed for the U.S.A., with emerging and newly-developed plays including three from Canada, and one from China.

Dew-Mimms Creek Field, East Texas Basin, U.S.A.

The Bossier Formation sandstones in the Dew-Mimms field are part of the Jurassic Cotton Valley Group in the East Texas Basin. The Cotton Valley Group is a succession of sandstone, shale and limestone that underlies most of the northern coastal plain of the Gulf of Mexico from Alabama to East Texas. The Cotton Valley Group is the first major input of clastic sediments into the ancestral Gulf of Mexico, with major depocenters in Mississippi, along the border of Louisiana-Mississippi, and in northeast and eastern Texas. Along the updip margin of the East Texas Basin, during the first phases of deposition of the lower Cotton Valley Group (Bossier sands), small alluvial fan-deltas developed, which through time evolved into more mature drainages. Through time, alluvial fan-deltas prograded basinward into wave-dominated delta systems at the northwestern limit of the ancestral Gulf of Mexico.

Individual sandstones with the Bossier Formation and the Cotton Valley Group are typically highly lenticular, with difficulty in correlations between wells. One strategy is to allow multiple sandstones to produced together in each wellbore, to facilitate recovery from marginal sandstones that would otherwise not be produced. This has resulted in field consolidations, with commingling of the Cotton Valley Sand, the Bossier Sand, and the deeper Cotton Valley limestone (also known as the Cotton Valley Lime, equivalent to the Haynesville). The Dew-Mimms field produces from a series of stacked sand-shale successions containing 75-100 feet (23-30 m) of net sand with average porosities ranging from 6-10%, absolute permeabilities from 1 microdarcy to 1 millidarcy, and water saturations ranging from 5-50%. The play seeks to exploit an overpressured cell by drilling for gas close to the overpressure ceiling which is at depths of 12,400 – 13,200 feet (3,780-4.023 m). The Dew-Mimms Creek field is being developed on a 80-160 acre (32.4-64.8 ha) well spacing. Wells are fracture stimulated with small to large slickwater fracs by pumping 100,000 to 350,000 pounds (45,360 to 158,757 kg) of proppant. Initial well rates range from 2-5 million cubic feet per day (MMcfd) (56.6-141.5 thousand cubic meters per day) and declines are hyperbolic with flows stabilizing after 2-3 years at 500-900 thousand cubic feet per day (Mcfd) (14.2-25.5 thousand cubic meters per day). Estimated ultimate recoveries (EURs) per well range from 1-4 billion cubic feet (Bcf) (28.3-113.2 million cubic meters). Geological factors controlling well success include the ability to locate main channel sand trends where sands are thicker and of better quality, and to established sustained economic production rates from inferior reservoirs through improved completion practices.

Jonah Field, Green River Basin, Wyoming, USA.

The Cretaceous Lance Formation sands are located in the Jonah field, northwestern Green River Basin, of Wyoming. In the 1990s, the Jonah field was one of the largest onshore gas discoveries in the U.S.A., which is remarkable since the productive sandstones have average porosities and permeabilities that would normally not be considered reservoir rock, but rather as cap rock or seals in many conventional hydrocarbon fields. What distinguishes the Jonah field are the large net pay thicknesses of the low-permeability tight gas sandstones and the large areal extent of the field. The Jonah field is located in the greater Green River Basin, with the primary producing interval being the Lance Formation. The Lance Formation unconformably overlies undifferentiated units of the Mesaverde Group, and is unconformably overlain by unnamed Tertiary successions. Although the Jonah field is one of many basin-centered accumulations within the greater Green River Basin, it is considered by industry to be typical of the unconventional tight gas sands types in the area. Debate exists as to whether these basin-centered accumulations are part of a single regionally extensive accumulation, or if they are discrete accumulations, with conventional subtle traps. In either case, the Jonah field is a sweetspot that is delineated on a structural feature, that has converging faults along flanks of a major anticline (the Pinedale), with updip trapping against boundary faults. It thus appears that the Jonah field is an unconventional, basin-centered accumulation with conventional trapping mechanisms. The top-seal for the field is a combination of all mudstones throughout upper Mesaverde, Lance and Tertiary successions. Most of the Lance Formation sandstones were emplaced as either individual fluvial channel sands, or as amalgamated and stacked fluvial channel systems. A number of studies show variable paleocurrent trends (SW to NE, and NW-SE), which may indicate either multiple sources, switching of paleoflows associated with braided fluvial systems, and/or tectonic influences on paleodrainage divides related to synsedimentary faulting in the area. The majority of the Lance reservoir sandbodies have widths that are significantly less than the typical well spacing of 40 acres. Tight gas production at Jonah is from a zone where permeability is enhanced, due to the confluence of two major faults.

The Jonah field is fault-bounded and contains a stacked succession of 20 – 50 fluvial channel sands in an interval that is 2,800-3,600 feet (853-1,097 m) thick, and occurs at depths of 11.000-13,000 feet (3,353-3,962 m). Sandstone bodies occur as individual 10-25 foot (3.0-7.6 m) thick channels that are stacked into channel sequences up to 200 feet (61 m) thick. Porosities range from 5-14%, with permeabilities of 1-30 microdarcies and water saturations of 30-60%. Pressure gradients are 0.55 – 0.60 psi/foot (37.9-41.3 millibars/0.3 m). Wells are completed by pumping multiple fracture treatments (8-20) into wells that are nearly vertical through the Lance Formation. The hydraulic fracturing design includes 100,000-400,000 pounds (45,360-181,440 kg) of sand in a cross-linked borate gel and a 25-50% nitrogen assist in each stage which is typically < 200 feet (61 m) long. Current development is on a 20-40 acre (8.1-16.2 ha) well spacing with 10-acre (4 ha) and 5-acre (2 ha) pilot areas). It is estimated that 67% of the original gas in place (OGIP) can be recovered at a 10-acre (4-ha) spacing and 77% at a 5-acre (2-ha) spacing. Initial well rates range from 5-15 MMcfd (142-425 thousand cubic meters per day) with EURs ranging from 5 to 10+ Bcf (141.5 – 283 thousand cubic meters) per well.

Mamm Creek Field, Piceance Basin, Colorado, USA.

The Mamm Creek field accounts for about 75% of the current gas production from the Piceance Basin of northwestern Colorado. The Mamm Creek field has production from the tight fluvial

sandstones of the Williams Fork Formation (depth 5000 feet), with additional contributions from other marine sandstones of the Corcoran, Cozzette and Rollins Members (7000 feet deep). The Williams Fork Formation is mainly a low-porosity and low-permeability tight-sandstone that is within a basin-center gas accumulation. The Williams Fork deposits are fluvial channel sands, crevasse splays, overbank and floodplain mudstones and coals that were deposited within an evolving paleogeography of meandering- /braided-fluvial → marsh, mire, swamp, estuarine → shoreface/deltaic and coastal/alluvial plain systems tracts. Pay sands are mainly the point bars, braid bars, and marine sandstone units. The complexities of the fluvial-marginal marine systems have resulted in a very heterogeneous connectivity of the tight-sandstone reservoirs, with variations dependent upon lithology, stratigraphic architecture, and shoreline stacking patterns. In addition to the original sedimentological controls, other variables relate to the main fault types, the distribution of fractures within the reservoirs and other associated basin-center accumulations.

In the Mamm Creek field the main producing interval is the 2,000-foot thick overpressured Williams Fork Formation which consists of lenticular fluvial to marine sands at depths of 4,500-8,500 feet (1,372-2,591 m). Packages of "stacked sands" can be correlated over areas of 30 – 70 acres (12-28 ha). Results from 200 well tests showed permeabilities ranging from 1-100 microdarcies with half the tests indicating the presence of open fractures. Each development pad contains 12-16 wells that are vertical through the reservoir and completed with 4-10 slickwater fracture stimulation stages using 50,000-500,000 lbs (22,680-226,800 kg) of sand and 2,000-13,000 barrels (318-2,067 cubic meters) of water per stage. Larger treatments lead to longer half-lengths, which in turn result in higher production and EURs. Each well costs about 1.2 million dollars (MM$) which is equally divided between the drilling and completion costs. Wells have been downspaced to 20 acres (8.1 ha) and recent evidence indicates that it may be optimal to downspace to 10 acres (4 ha) in order to recover 75% of the OGIP.

Wamsutter Field, Green River Basin, Wyoming, USA.

The Wamsutter field covers a 50 square mile (129 square kilometer) area in the greater Green River Basin of Wyoming, and contains an estimated 50 Tcf (1.42 trillion cubic meters) of OGIP. The reservoir consists of stacked marine and fluvial sands of the Upper Cretaceous Almond Formation, Mesaverde Group, and numerous turbidites within the Lewis Shale. Regionally, the Almond Formation has thickness ranges from 250 to > 500 feet, with variations in thickness and lithologies related to basement block-fault structures. The Almond Formation represents deposition associated with a major overall transgression, with superimposed smaller transgressive-regressive cycles. The Main Almond is mainly a brackish to nonmarine succession of interbedded sandstone, siltstone, shale and coals, with the Upper Almond consisting of mainly amalgamated marine 'bar' complexes. The Upper and Main Almond units are separated from one another by a transgressive regional marine shale. Sedimentologically the Main Almond consists of discontinuous, lenticular tidal flat and tidal channel sandstone bodies that are encased within more muddy bayfills and estuarine shale successions. Individual sequences are bounded by continuous coals and carbonaceous shales. There is a marked heterogeneity of the reservoir sands, which have little connectivity to one another. Most of the Main Almond reservoir sandbodies have widths that are significantly less than the typical well spacing. Conditions within the Almond Formation become more marine upsection associated with major

transgression. Upsection this results in an increase in connectivity of the different reservoir sandstones. The Upper Almond is an amalgamated succession of laterally continuous, amalgamated shoreface deposits, which are cut by tidal channel complexes. The main producer is the Upper Almond, with supplemental production from the underlying Main Almond. Productivity from different sandstones varies significantly, and is influenced by a variety of factors, including sand reservoir connectivity, lithology, matrix, fracture density and the presence of nearby faults, and proximity to coal sources.

The Wamsutter field currently produces 450 MMcfd (12.7 million cubic meters per day) of gas from more than 2,000 wells. The Almond Formation is generally encountered between depths of 8,500 and 10,500 feet (2,590 and 3,200 m) with reservoir pressures varying from initial conditions (0.54-0.58 psi/ft; 37.2-40 millibar/0.3 m) in the Lower Almond to varying stages of pressure depletion in the Upper Almond. Sands typically have 8-12% porosity and 2-30 microdarcies of permeability. The average net pay footage ranges from 50-80 feet (15-24 m) per well. Completion depths range from 7,000 feet (2,133 m) for shallow Lewis Shale wells to 12,200 feet (3,718 m) for deep Mesaverde wells. The Mesaverde is completed in 2-3 stages, and the Lewis is completed in 1-2 stages. Fracture stimulations total 40,000 gallons (151 cubic meters) of borate-crosslinked guar fluid and 175,000 pounds (79,380 kg) of 20/40 mesh sand or lightweight ceramic proppant. A typical initial gas rate for a fracture stimulated well is 1 MMcfd (28 thousand cubic meters per day) with an average recovery of 2 Bcf (56.6 million cubic meters) per well. Since, 2004, BP, one of the big operators in the Wamsutter field, has drilled over 300 eighty acre (32.4 ha) infill wells and recently has been evaluating the possibility of infilling with wells at a 40 acre (16.2 ha) spacing.

Cardium Formation, Western Canada Sedimentary Basin, Alberta, Canada.

In Alberta, at present, it is difficult to classify the remaining established gas reserves as ‘conventional’ or ‘unconventional.’ Traditionally, for conventional production, the Cretaceous reservoirs account for ~ 75% of the province’s remaining established reserves of marketable gas and is important as a future source of natural gas. Much of the current investment in the Western Canada Sedimentary Basin of Alberta is focused on the liquids-rich gas held in the fine-grained fringe deposits (or ‘halos’) of the Cretaceous Cardium Formation of the Colorado Group. The Cardium Formation hosts about 25% of Alberta’s discovered conventional oil, with > 10 billion barrels of oil-in-place, with cumulative production (1957-2009) of ~ 1.75 billion barrels. This recovery of only 17% has been by conventional drilling and completions strategies that used vertical wells in various parts of the formation, with a combination of primary and enhanced oil recovery (EOR). Beginning in late 2008, there has been significant redevelopment of the Cardium Formation using multi-stage horizontal wells, with hydraulic fracturing, which has significantly increased production, by renewing development in under-developed areas of the conventional pools and recovering by-passed pay, and by new development in undeveloped areas between the conventional pools. As of June 2010 over 120 of these wells have been placed on production, largely in the Pembina and Garrington/Caroline fields. Cardium reservoirs typically occur at depths between 1200-2800 m and have mainly light oil with varying amounts of dissolved gas, along with a number of rich-gas pools. Conventional sand and conglomerate reservoirs are relatively thin (4 – 10 m), porosities 6 – 15%, with > 200 millidarcy

permeabilities. Data are not available regarding porosity and permeability characteristics of the unconventional fringes around the conventional pools, but are generally in the range of other tight gas sands being exploited in the U.S.A. Cardium fracs typically take 25-40 tons of proppant, compared to 200-300 tons of proppant of typical shale-gas fracs.

The Cardium Formation is regionally extensive in central and southern Alberta, spanning about 150 townships (each township is 36 square miles or 23,040 acres). Sandstone reservoirs are largely in three-stacked successions of largely marine sandstones that formed part of the clastic wedge in the Western Canada Sedimentary Basin. Most of the conventional sand-reservoirs were emplaced in offshore tidal-shelf settings, as mainly coarsening-up successions associated with transgressions following relative falls in base-level throughout the basin. Locally, regressive and early transgressive reservoir sands include incised estuarine valley fills, marginal marine, and shoreface settings. Surrounding the conventional sand reservoirs are 'lobes', 'halos' or 'fringes' of the largely tight, thin-bedded, bioturbated, mixed lithologies of very fine sandstone, siltstone, mudstone and shale. Permeability in these thin-bedded mixed lithologies is much less than the associated conventional reservoir sands (< 0.5 millidarcies). These fringes are what are largely being developed by the multi-stage fractured horizontal wells. Early production data shows that horizontal wells with longer lengths seem to consistently outperform those horizontal wells with shorter lengths in these fringe areas. Due to lack of long production time on these wells it is impossible at this early stage to comment on the impact of the number and type of fracture stages that are optimal per well. 3-D and stochastic modeling results indicate that for the Pembina field, horizontal fractured well drilling and completions for bypassed pay within the conventional pools, commingled with the associated liquids-rich gas in the fringe deposits, may yield up to 13% after about 25 years of production.

Part of the strategy for economic recovery of liquids-rich gas or recovery of both gas and oil is to horizontally drill both the fringe and the remnants of the conventional pools, thereby making the commingled bypassed pay in the conventional pool-and-new pay in the fringe areas economic. Operators have found that several of the fringe wells produce at lower initial rates than the vertical wells centrally located within the conventional Cardium pools, but have similar low annual decline rates as the conventional pools. First-month initial production rates in other Cardium areas, such as Williston Green and Buck Lake, range from 300-500 barrels per day, which is expected to level off to 80-100 barrels/day. The main challenge for operators to develop the induced fractured fringe areas is to find ways to push the boundaries of conventional pools with existing pay cutoffs of liquids rich gas and/or light oil, and to add the additional potential of the un-drained volumes of the distal portions of the Cardium pools, which until now, have not been economic to produce. This particular example is one in which there is a clear continuum of fluids, reservoir, and development strategies between the older (but now renewed) conventional pools, and the emerging fringe tight-gas and liquids-rich gas accumulations in the distal edges of the conventional pools.

Nikanassin Formation, Western Canada Sedimentary Basin, NE British Columbia and NW Alberta, Canada.

The Late Jurassic-Early Cretaceous Nikanassin Formation occurs in the northern mountains, foothills and plains of the Western Canada Sedimentary Basin, as an easterly-thinning wedge of largely non-marine sediments. The Nikanassin Formation has a maximum thickness > 1,000 m, and is generally encountered at depths of 1,000 m in the northern plains, and up to 3,500-4,000 m in the deep foothills. On average, the Nikanassin Formation consists of about 30% sandstone. Thinner reservoir sands (5 – 15 m thick) are fluvial channel fills, many as fining-upwards successions, interbedded with siltstone/shale, with associated coals. The thicker stacked sandstone successions (> 50 – 500 m) were deposited within stacked fluvial channel sands within non-marine incised valley-fills. Porosities range from 6-10%, with relatively low permeabilities of 0.01 - 1 microdarcies (md). Sandstones lack original primary porosity, having been destroyed by cementation, with little development of secondary porosity. Reservoir sandstones are brittle and glassy, with breakage across sand grains; however, where tight sands are productive they are extensively fractured. Gas was generated in the associated coals, with the regional conventional trapping mechanism (either stratigraphic or structural), and similar to the Mesaverde Group of Colorado. Development of the Nikanassin has been within tight gas sand pools that align with structural trends of the thrust belt of northeastern British Columbia and the adjacent areas of northwestern Alberta. The structural grain of the fold and thrust belt is NW-SE, and the main fairways of development are along the leading edges of the thrust faults. The Nikanassin is largely a structural play where deformation associated with the thrust belts has fractured the brittle sandstones to create sufficient porosity and permeability for productive wells. Generally, Nikanassin pools off trend of the thrust-faults are non-productive. A maximum of five zones within the Nikanassin are drilled and completed, with each zone stimulated separately by hydraulic fracturing. There is a relatively short period of production from these wells, but early returns show production up to 3.2 BCF (90, 000,000 cubic meters), some of which may be commingled with uphole reservoirs. Since 1979, one of the Nikanassin wells has produced 20.4 BCF (577, 000,000 cubic meters).

Montney Formation, Western Canada Sedimentary Basin, NE British Columbia and NW Alberta, Canada.

Although the Triassic Montney Formation has typically been considered a ‘shale gas,’ it is actually (in large parts of the formation) a thin-bedded succession of mixed lithologies, including lower shoreface/distal delta fringe deposits of stacked siltstone and very fine sandstone (with little shale or mudstone components) that overlie a deeper basinal facies of fine-grained, organic-rich mudstone/shale, cut by low stand turbidite sandstones. Production is essentially from two areas: the foothills of northeastern British Columbia, and the deep basin area of northwestern Alberta. The delta fringe/shelf siltstones in British Columbia have an estimated gas-in-place of 25-40 BCF/section, with the lower Montney turbidites having gas-in-place of 30-50 BCF/section; predicted development programs are projected to sustain production of 50-100 MMcf/d. The Triassic Montney Formation occurs in the northwest plains and deep basin areas of the Western Canada Sedimentary Basin of Alberta and British Columbia. The successions were deposited as a broad ramp on the western edge of the North American craton during Triassic time. The traditional ‘good’ conventional reservoirs are located in the more shallow, updip portions of the continental ramp, mainly in northwestern Alberta. By contrast, the deeper, downdip portions of the continental ramp succession (largely located in the deep basin areas of

both Alberta and British Columbia) are the distal unconventional shale gas reservoirs, with a continuum of conventional to unconventional reservoirs through time and space. Historically, the lower Montney Formation has been the focus of deep exploration by conventional development of the distal sandstone turbidites, which have fairways that have been exploited with moderate reservoir qualities in western Alberta and northeastern British Columbia. Since 2003, the more unconventional, updip portions of the upper Montney tight gas sandstones and siltstones have been developed using multi-stage multi-frac horizontal wells.

The upper Montney are the stacked distal shoreface/delta fringe and shelf sandstone and siltstone packages which have aggregate thicknesses up to 156 m thick. The upper Montney, again historically called a 'shale-gas', is really a thinly interlaminated succession of largely siltstone, with very fine sandstone, and dark, organic and pyritic mudstone, with stacked reservoirs attaining thicknesses > 100 m. Porosities in these unconventional reservoirs are typically <3% - 10%, with < millidarcy permeabilities. Initial development in 2005 in northeastern British Columbia used several stages of hydraulic fractures first in vertical wells, now being developed solely by horizontal wells, with average initial flow rates of >4 million cubic feet per day (MMcf/d), and initial decline rates on the order of 60%, stabilizing at single-digit rates of decline with a 'long-producing tail.'

Shuixigou Group, Taibei Depression, Hami Basin, Kekeya Area, China

The lower Jurassic Shuixigou Group sands in Taibei Depression, Hami Basin in the Kekeya area of China contains three stacked successions of tight gas sand braided delta-front reservoirs that debouched into a largely lacustrine basin, with associated thick coal measures (500 – 1100 m thick). Burial depths of the tight gas sand reservoirs is 2,800 – 4,300 m. The field produces from a series of stacked sand-pebbly sand, interpreted mainly as subaqueous braided delta front channel-fills, with porosities of 4- 8.4 % and permeabilities of 0.077 – 3.61 millidarcies. Within the three gas-bearing successions, individual sand reservoirs range from 18 – 55 m, with gross thicknesses of the stacked successions 105 – 280 m thick. The play seeks to exploit fractured reservoirs, with the highest production from fractured (micro- and macro-scale,) reservoirs on structural highs, with lowest production in the relatively unfractured zones within adjacent structural lows. Single well gas productions vary from 1.9 – 7.6 x 104 m3/d. Natural gas traps are conventional, combined stratigraphic-structural traps, including faulted anticlines, fault block horst-and-graben structures. The high-production tight gas sand reservoirs are largely controlled by the tectonic setting of the area, and the nature of the natural fracture/fault system. The most favorable areas for tight gas are located on structural highs, with high densities of fractures, and thick top coals (20 – 30 m thick). The second-most favorable areas are located also on structural highs with high fracture densities, but in areas where the thickness of the sand and pebbly sands reservoirs are variable, and the coal top is quite variable. The geological factors that control the productivity of single wells within the typical tight gas reservoirs relate to the structural location, the sedimentary facies, intensity (or density) of natural fractures, and close proximity to thick and continuous top coal measures.