# Tight-Gas Sands Committee Report

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by

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## Executive Summary

Tight gas is an unconventional type of hydrocarbon resource within reservoirs that are low permeability (millidarcy to microdarcies range) and low porosity, as in 'tight sand'. "Distal" unconventional tight-gas sands (with high sandy silt/siltstone content, low clay/shale content, but with self-sourced organics) have more recently been called "hybrid" shales. In these types of reservoirs gas cannot be extracted easily or economically without expending much technological effort to artificially enhance the permeability, such as by fracturing and/or acidizing the formation; also, under present market conditions, it is clear that tight-gas sands must also include a high-liquids component to become profitable.

The U.S. Energy Information Administration ((EIA)) estimates that about 310 Trillion cubic feet (Tcf) (8.8 trillion cubic meters (Tcm)) of technically recoverable tight gas exists within the United States representing about 17% of the total recoverable gas, with worldwide estimates of > 7,400 Tcf to as much as 30,000 Tcf (210 – 850 Tcm). 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, and the Ukraine (Donetsk-Dnepr Basin). McGlade et al. (2012) use prior publications and estimate 54.5 Tcm (1914 Tcf) of technically recoverable tight gas from 14 regions or countries in the world.

This report summarizes tight-gas sand characteristics and activities in the United States, China and Canada, specifically in the Dew-Mimms Creek Field, East Texas Basin, U.S.A.; the Jonah and Wamsutter fields, Green River Basin, Wyoming, USA.; the Mamm Creek Field, Piceance Basin, Colorado, USA; the Cardium, Nikanassin and Montney formations, Western Canada Sedimentary Basin, Alberta and British Columbia, Canada; and the Shuixigou Group, Taibei Depression, Hami Basin, Kekeya Area, China. We will endeavour to high;light new areas of global tight gas development of the next year. Some of these successful plays in the USA, Canada and China are commingled with 'fringe' deposits from otherwise conventional oil and gas plays, including liquids-rich gas from organic-rich, fine-grained, mixed-bed lithologies. A continuum from fringe conventional oil and gas plays to unconventional tight-gas sands to unconventional tight-shale gas clearly exists and the distinction between these various hydrocarbon commodities will become less clear as development of these plays continue to evolve.

## Introduction

Tight gas is an unconventional type of hydrocarbon resource within reservoirs that are low permeability (millidarcy to microdarcies range) and low porosity, as in 'tight sand'. In these types of reservoirs the gas cannot be extracted easily or economically without expending much technological effort to artificially enhance the permeability, such as by fracturing and/or acidizing the formation.

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. According to McGalde et al. (2012) tight gas may be developed in many other areas of the world but estimates have been difficult to gather, in some cases because tight gas is included in conventional gas estimates. Nonetheless, McGlade et al. (2012) "presents an overview of the current estimates" of 54.5 Tcm (1914 Tcf) of technically recoverable tight gas from 14 regions or countries in the world.

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 (cf. King. 2012 )], economics (well completion and drilling costs and gas prices), and environmental concerns (impacts on water resources, remediation, GHG emissions).

Under present market conditions, it is clear that tight-gas sands must also include a high-liquids component to be profitable – that is, many of the successful plays may be commingled with 'fringe' or 'halo' deposits from otherwise conventional oil and gas plays, including liquids-rich gas 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 horizontal drilling and multi-stage hydraulic fracturing, there will be a continuum from fringe conventional oil and gas plays to unconventional tight-gas sands and unconventional tight-shale gas, and that the present distinctions between these various hydrocarbon commodities will become less clear. Some of the more "distal" unconventional tight-gas sands (those with a high sandy silt/siltstone content and relatively low clay/shale content, but with self-sourced organics) have recently been called "hybrid shales."

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 (see below), and the Ukraine (Donetsk-Dnepr Basin).In Canada, tight-gas sand plays have been pursued (and produced actively) since about 2005, 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, it has been determined that many of these plays in the Western Canada Sedimentary Basin need completion and drilling strategies that are geo-tailored to the subsurface geology of the area.

Given the current price of hydrocarbons, liquid-rich gas or oil-rich targets are economically preferred. For this reason, some tight-oil plays are included. Tight-gas and -oil sandstone projects with long production histories may provide insights and analogs for the appraisal and development of new emerging areas. 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 two from China. Future updates to this report will include a more broad-spectrum of emerging tight resource plays from other regions or countries.

## Tight Gas and Oil Summaries

This report summarizes tight-gas and tight-oil sand characteristics and activities in the United States, China and Canada, specifically:

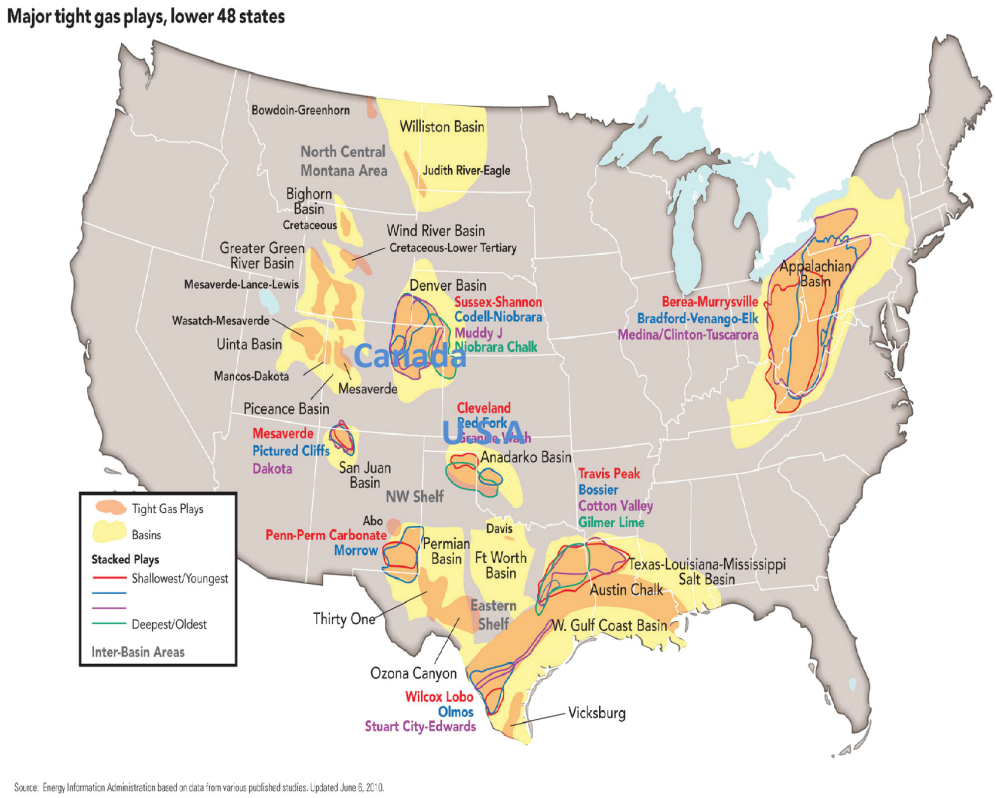
- Dew-Mimms Creek Field, East Texas Basin, U.S.A.
- Jonah and Wamsutter fields, Green River Basin, Wyoming, USA.
- the Mamm Creek Field, Piceance Basin, Colorado, USA
- Cardium, Nikanassin and Montney formations, Western Canada Sedimentary Basin, Alberta and British Columbia, Canada
- Shuixigou Group, Taibei Depression, Hami Basin, Kekeya Area, China
- Siluge Tight Gas Field, Ordos Basin, China

Most of the material is taken from the following sources:

1. the Tight Gas Sands Committee contribution to the bi-annual EMD publication in Natural Resources Research (Jenkins, 2011)
2. compilations from previous EMD Tight Gas Committee annual and mid-year reports on the EMD Members' Only website (Jenkins, 2010; Hein and Jenkins, 2011)
3. Hart's Unconventional Gas Center (www.ugcenter.com)

## U.S.A.

A map showing the different basins and major tight-gas plays in the U.S.A. is given in Figure 1.




1. Figure 1. Major Tight Gas Plays in the U.S.A. (June 2010; http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm)

## 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 that accounts for about 1% of the production from 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 alluvial fan-deltas that 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 correlating between wells. One strategy is to commingle production from multiple sandstones 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 Creek 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 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, 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 an average porosity and permeability that, at the time of discovery, would normally not be considered reservoir rock, but rather as a cap rock or seal. What distinguish the Jonah field are the large net pay thickness of the low-permeability 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 sandstone 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 mudstone from the upper Mesaverde, Lance and Tertiary succession. 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. Porosity ranges from 5-14%, with permeability of 1-30 microdarcies and water saturation from 30-60%. The pressure gradient is 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). Cumulative It was 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 ranged from 1.3 to 6.1 MMcfd with EURs ranging from1.5 to 5.7 Bcf per well.

In the Jonah field there are currently 1876 gas wells, 73 dry holes or suspended wells (likely plugged), and 112 permitted locations or actively/completing wells. Cumulative production reported to date (to 2013) for 1818 wells (97% of wells in the Jonah field) are: 3860 BCFG, 36.4 MMBO, 39.6 MMBW, WGR 10.3 bbls/MMCF.

## Mamm Creek Field, Piceance Basin, Colorado, USA.

The Mamm Creek field accounts for about 20% of the current gas production from the Piceance Basin of northwestern Colorado. The Mamm Creek field produces from the tight fluvial sandstones of the Williams Fork Formation (depth 5000 feet), with an additional contribution 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 à marsh, mire, swamp, estuarine à shoreface/deltaic and coastal/alluvial plain systems tracts. Pay sands are mainly within the point bars, braid bars, and marine sandstone units. The complexity of the fluvial-marginal marine systems has resulted in a very heterogeneous connectivity of the tight-sandstone reservoirs, with variations in sandstone connectivity 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 permeability 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.

Drilling has slowed considerably in the Piceance Basin due to depressed gas prices. Cumulative production reported to date (to 2013) for 3780 wells are: 1222 BCFG, 10.5 MMBO, 69.9 MMBW, WGR 57.2 bbls/MMCF.

### Wamsutter Development Area, Green River Basin, Wyoming, USA.

The Wamsutter development area 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 thickness of the Almond Formation ranges from 250 to > 500 feet (76 – 152 m), with variations in thickness and lithologies related to basement block-fault structures. The Almond Formation represents deposition associated with a major overall transgression and 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 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 coal and carbonaceous shale. There is a marked heterogeneity of the reservoir sands, where little connectivity exists between sand bodies. Most of the Main Almond reservoir sand bodies have a width that is significantly less than typical well spacing. Conditions within the Almond Formation become more marine up-section associated with a major transgression resulting in an increase in connectivity of 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 reservoir connectivity, lithology, matrix, fracture density and the presence of nearby faults, and proximity to coal sources.

In the Wamsutter field , the Almond Formation is generally encountered between depths of 8,500 and 10,500 feet (2,590 and 3,200 m) with reservoir pressure 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. As of the end of

2013, 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 (28.3 thousand cubic meters per day) with an average recovery of 2 Bcf (56.6 million cubic meters) per well). Since 2004, one of the big operators in the Wamsutter field (BP) 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.

The greater Wamsutter area consists of over 15 federal units with various companies defining the area differently. Taking the deep basin gas as "Wamsutter" there are currently (as of 2013) over 4000 wells in the area, consisting of > 3600 gas wells, ~ 100 dry or suspended, and 365 permitted locations or actively/completing wells. According to BP, they have achieved dramatic cost reductions through moving to multi-well pad development which allows them to continue development in a challenging gas-price environment. Cumulative production reported to date (to 2013) for 3730 wells are: 3385 Billion cubic feet of gas, 52.7 Million barrels of oil, 53.6 Million Barrels of water, and a water/gas ration of 15.8 barrels per Million cubic feet of gas/.

Note: All three areas discussed above (Jonah, Mamm Creek, and the greater Wamsutter area) produce at water/gas ratios (WGR) substantially in excess of the water-vapor content of natural gas at reservoir conditions (2-5 bbls/MMCF depending on depth and temperature). This is corroborated by the salinity of the produced water, which although variable, is not as fresh as would be water of condensation. This is a common aspect of tight-gas production in the Rocky Mountains, where the fields all produce water and management of produced water is a significant issue.

## CanadaWestern Canada Sedimentary Basin, Alberta, Canada

At present, in Alberta it is difficult to classify the remaining established gas reserves as 'conventional' or 'unconventional'. Traditionally, Cretaceous conventional reservoirs account for ~ 75% of the province's remaining established reserves of marketable gas and continue to be an important future source of natural gas. Recent advances in drilling and completions technologies have opened up what may now be considered, unconventional, low-permeability zones for economic production. These include

- tight-sand gas,
- tight-liquids-rich sand gas,
- tight-sand oil and,
- tight mixed-bed lithology oil and gas.

These types of deposits are more continuous gas and oil accumulations in the basin center and transition zones (Figure 2).

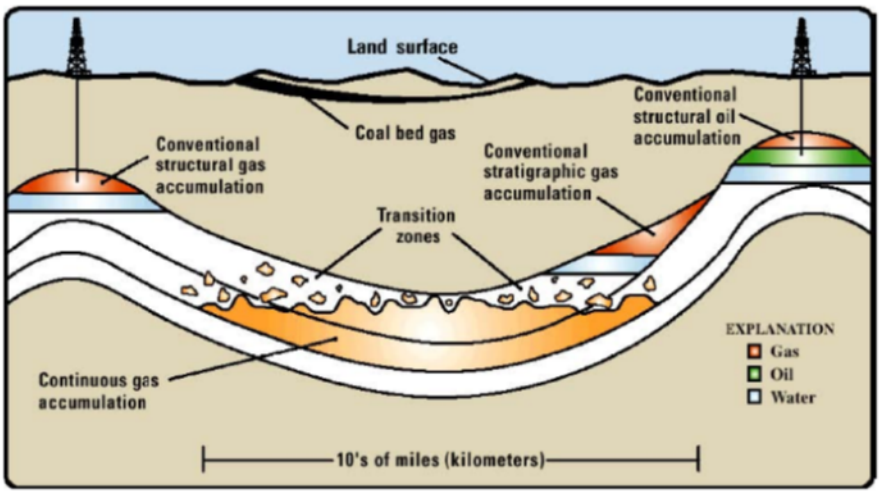



Figure 2. Schematic illustrating the different types of onshore natural gas plays. Conventional resources are buoyancy-driven hydrocarbon accumulations, with secondary migration and structural and/or stratigraphic closures. Unconventional, continuous gas accumulations, in basin centered and transition zones, are controlled by expulsion-driven secondary migration and capillary seal (from US Geological Survey Inventory of Onshore Federal Oil and Natural Gas Resources and Restrictions to Their Development (2008) ("EPCA Phase III Inventory") (p. 46).

Unconventional technologies are being used for enhanced hydrocarbon recovery from what were previously depleted conventional fields, and for the surrounding transition zone and basin-centered accumulations. Thus, there appears to be a 'blending' of the conventional versus unconventional (transition and basin-centered accumulations) in these technology-driven plays – everything is being produced, the gas, the liquids-rich gas, and the oil from the artificially-fractured (and often commingled) conventional, conventional fringe or halo, transition, and basin-centered accumulations. For these reasons, the Cardium-play, in particular, appears to be a hybrid of both conventional and unconventional resources, with most of the production, at present, coming from the low-permeability liquids-rich gas zones and/or oil zones; hence, it was decided to discuss this play-area under the tight gas sandstone commodity, although parts of it would also fall into the unconventional oil shale or conventional hydrocarbon commodities.

In Alberta, drilling statistics to December 2014 show the top drilled strata (non-heavy oil) are Cretaceous Cardium and Viking formation sandstone haloes, Triassic Montney Formation tight sandstone/siltstone, and Beaverhill Lake Group tight carbonate for gas/liquids and oil. Horizontal multistage fractured (HMSF) gas/liquid well completions increased from 626 to 846 wells from 2013 to 2014, while HMSF oil well completions decreased from 1612 to 1506 during the same period. No frac log of drilled but uncompleted wells is available at this time.

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

Much of the current investment in the Western Canada Sedimentary Basin of Alberta is focused on the liquids-rich gas or tight-oil held in the fine-grained fringe deposits (or 'haloes') 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, and cumulative production (1957-2009) of ~ 1.75 billion barrels. The recovery of only 17% of the pools has been accomplished using conventional drilling and completions strategies with vertical wells and 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 and hydraulic fracturing. Production has significantly increased both by renewing development in under-developed areas of the conventional pools and hence recovering by-passed pay, and by new development between the conventional pools. Cardium reservoirs typically occur at depths between 3,937-9,186 feet (1200-2800 m) and have mainly light oil with varying amounts of dissolved gas, along with a number of liquid-rich gas pools. Conventional sand and conglomerate reservoirs are relatively thin (13-32 feet or 4 – 10 m), porosity of 6 – 15% and > 200 millidarcy permeability. There are few data representing porosity and permeability of the unconventional pools that are published, available data appears similar to other tight-gas sandstones 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 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 haloes or fringes are what are largely being developed by the multi-stage hydraulically-fractured horizontal wells. Early production data shows that horizontal wells with longer lengths seem to consistently outperform 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 an additional 13% hydrocarbon after about 25 years of production.

Since fall 2009, the Cardium play has had a sharp increase in horizontal play activity, initially largely focused on the Pembina and Garrington fields of central Alberta. The Cardium occurs at 4,265 feet (1300 m) (vertical depth) at Pembina, and at 5,905 feet (1800 m) (vertical depth) at Garrington. As of 2013, each well costs between 2.8 and 3.0 million dollars (MM$) per well, divided between the drilling and completion costs (Anderson, 2011). Wells have been down-spaced to 20 acres (8.1 ha) and recent evidence indicates that it may be optimal to down-space to 10 acres (4 ha) in order to recover 75% of the OGIP. Initial horizontal wells in the Pembina area were drilled by industry with a monobore design, and then fractured with oil-based systems, using interstage fracture distances of 328 feet (100 m) over

horizontal well lengths of 2,625-4,593 feet (800 – 1400 m). By 2011, the company switched to a frac density of 18 frac stages per 4,593 foot (1400 m) horizontal well, and switched from oil-based to water-based fracturing.

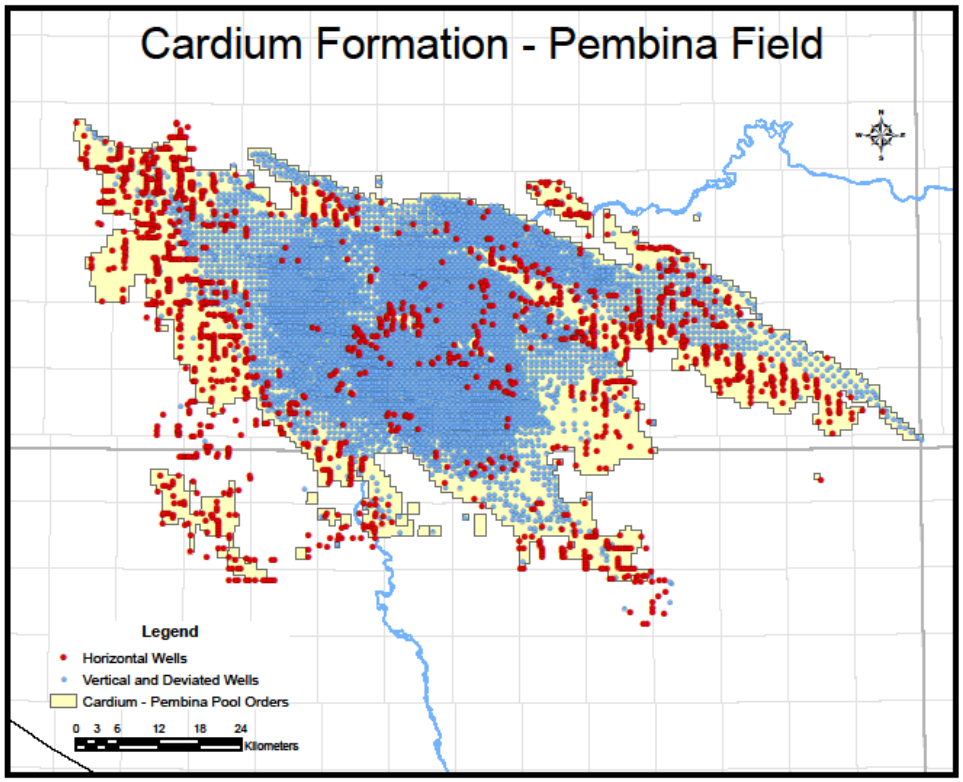



Figure 3. A map showing the growing horizontal activity into the 'halo' zones of one of the Cardium Formation fields in Alberta, Canada.

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. 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. 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/oil 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 > 3,281 feet (1,000 m), and is generally encountered at depths of 3,281 feet (1,000 m) in the northern plains and up to 11,483-13,123 feet (3,500-4,000 m) in the deep foothills. On average, the lithology of the Nikanassin Formation consists of about 30% sandstone. Thinner reservoir sands (16 – 49 feet or 5 – 15 m thick) are fluvial channel fills, many as fining-upwards successions, interbedded with siltstone/shale, with associated coals. The thicker sandstone successions (> 164-1,640 feet or 50 – 500 m) were deposited as stacked fluvial channel sands within non-marine incised valley-fills. Porosities range from 6-10% with a relatively low permeability of 0.01-1 microdarcies (µmd). 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 a regional conventional trapping mechanism (either stratigraphic or structural), similar to the Mesaverde Group of Colorado.

Drilling for Nikanassin dry gas has dropped off significantly in the last few years. Development of the Nikanassin has been within tight-gas sandstone 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 the 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) per well, 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). Representative tight Nikanassin horizontal well costs are not readily available; however, for vertical conventional wells, a typical Nikanassin well costs 7.5 million ($MM) per well to drill and complete, with initial production of 10 million to 15 million cubic feet per day (June-Warren Nickels, 2012).

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

The Montney formation continues to be a focus of activity in Alberta even in a lower price environment. Operators are continuing to seek ways to reduce drilling and completion costs.

The Triassic Montney Formation is 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 and shale 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 consisting of shoreface sandstones and coquinas 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 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 development of the distal sandstone turbidites 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 represents the stacked distal shoreface/delta fringe and shelf sandstone and siltstone packages which have aggregate thicknesses up to 512 feet (156 m) thick. The upper Montney is a thinly interlaminated succession of largely siltstone, with very fine sandstone, and dark, organic and pyritic mudstone, with stacked reservoirs attaining thicknesses > 328 feet (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.' The more recent drilling in the Montney is focused on liquid-rich gas or oil prone areas. In the Western Canada Sedimentary Basin, where infrastructure is in place, with short tie-ins, average horizontal well costs are ~ 4 million ($MM) per well, including drilling and completions.

## China

### China Tight Gas Sands

Tight gas drilling and production in China is booming, according to a Reuters News report (http://www.reuters.com/article/2013/07/08/china-tightgas-idUSL3N0EG2BF20130708 ) with tight gas production currently accounting for about a third of the total gas output. Present tight gas output of 30 Billion cubic meters (Bcm) is forecast to increase to 80 Bcm by 2020 and perhaps to 100 Bcm by 2030..

Tight-gas sandstone exploration started during the 1970s in China. Tight-gas sandstones are widely distributed in a number of basins including the Ordos, Hami (including the Taibei Depression, located in the Tu-Ha Basin, also called the 'Turpan-Hami' Basin), Sichuan, Songliao, Tarim, and deeper parts of the Junggar Basin (Figure 4, Table 1), with the favorable prospective areas exceeding 300,000 square kilometers. In early 2012, tight gas sands were considered one of the most promising unconventional resources in China (Xiaoguang Tong and Kechang Xie, pers. comm.., 2012). This is largely due to three factors: 1) the confirmed assessments of the tight gas-sands resource in China; 2) the advanced state of

technological development for tight gas-sands production; and, 3) the distribution of tight gas-sands in many areas previously developed for conventional gas plays, with existing infrastructure in place (Chengzao Jia, former vice-president of Petrochina, pers. comm.., 2012).

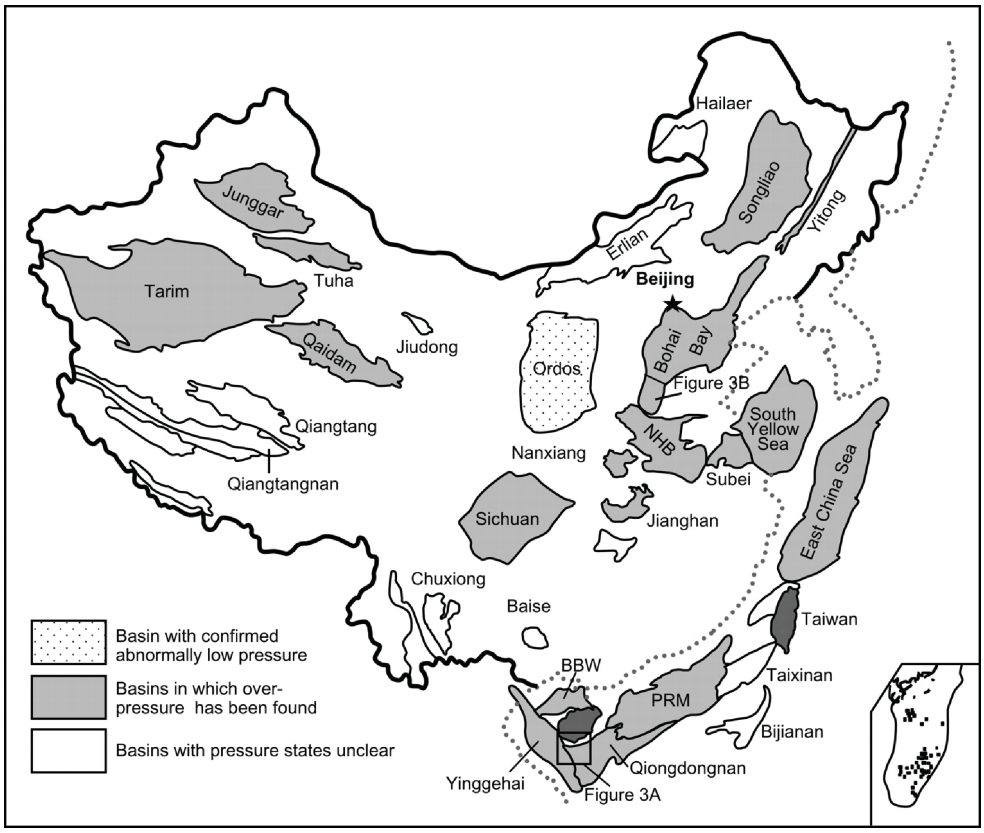



Figure 4. Location of China's major sedimentary basins (Hao et al 2007).

The tight-gas sandstone exploration in Tuha oil field (Hami Basin) made great progress in 2011, with drilling of the Ge-18 well in the field that had 3140 m3/d yield of gas in Shuixigou Group in May 2011. This is the only well of five exploratory wells within new formations that had a significant gas flow. These results will increase confidence for tight-gas sandstone exploitation in Shuixigou Group in the Taibei Depression. Another well is the Hongtai 21 (Tu-Ha Basin) which acquired commercial oil and gas flows in the Jurassic Sangonghe Formation in October 2011, indicating great progress for tight-gas sandstone exploration in Hongtai area. In December 2011, Sinopec commenced exploration and development for tight-gas sandstone in Ordos Basin.

The China National Petroleum Corporation, reports that more than 5000 wells have been drilled into the Sulige Tight Gas Field in the Ordos Basin of Inner Mongolia north central China. The field has a potential area of 40,000 km$^2$, cumulative proven gas-in-place of 1.68 Tcf and an upper potential of about 2.5 Tcf (CNPC 2010). The field is characterized by "low permeability, low pressure and low abundance". Sulige Gas field is reported to be a stratigraphic trap developed in Permian sandstone at a depth ranging from 3200 to 3500 meters. Induced fracturing occurs in three separate zones in the sandstone which are commingled for production. Wells have an average permeability to air of 0.1 to 2.0 mD and exhibit a rapid pressure drop after initial production.

| Basin | Depth (m) | Amount of Resources (TCM) |
|---|---|---|
| Ordos Basin | 2500 – 4500 | 8.4 |
| Sichuan Basin | 1500 – 4500 | 3.5 |
| Faulted Depression Beneath the Songlaio Basin | 1500 - 6000 | Not Estimated |
| Southern Deep Layer in the Junggar Basin | 4000 - 7000 | Not Estimated |

Table 1. Characteristics of main tight-gas sandstone reservoirs in China (Yukai et al., 2011)

The lower Jurassic Shuixigou Group sands in Taibei Depression, Hami Basin (part of the Tuha Basin) in the Kekeya area of China contains three stacked successions of tight-gas sandstones within braided delta-front reservoirs that debouched into a largely lacustrine basin, with associated thick coal measures (1,640-3,609 feet or 500 – 1100 m thick). Burial depths of the tight-gas sandstone reservoirs range from 9,186-14,108 feet (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 porosity of 4-8.4 % and permeability of 0.077 – 3.61 millidarcies. Within the three gas-bearing successions, individual sand reservoirs range from 59-180 feet (18–55 m), with a gross thickness of the stacked successions between 344-919 feet (105 – 280 m). The play seeks to exploit fractured reservoirs with the highest production from fractured (micro- and macro-scale,) reservoirs on structural highs, and the 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, and fault block horst-and-graben structures. The high-production tight-gas sandstone 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 a high density of fractures and thick top coals (66-98 feet or 20 – 30 m thick). The second-most favorable areas are located also on structural highs with a high fracture density, 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.

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***Tight Gas Sandstone- and Other Unconventional Related Conferences and Events***

AAPG: http://www.aapg.org/Events/Event-Listings

SPE: http://www.spe.org/events/about-events.php

## Tight-Gas Sandstone Weblinks

Alberta Energy Regulator: http://www.aer.ca
Alberta Geological Survey: www.ags.gov.ab.ca
BLM New Mexico, Texas, Oklahoma, Kansas: http://www.blm.gov/nm/st/en.html
British Columbia Oil & Gas Commission: http://www.empr.gov.bc.ca/OG/oilandgas/Pages/default.aspx
Bureau of Economic Geology: http://www.beg.utexas.edu/
Canadian Federation of Earth Sciences: http://earthsciencescanada.com/cfes/index.php
Canadian Society of Exploration Geophysicists: http://www.cseg.ca/
Colorado BLM: http://www.blm.gov/co/st/en.html
Colorado Department of Natural Resources: http://dnr.state.co.us/
Colorado Division of Water Resources: http://water.state.co.us/
Colorado Geological Survey: http://coloradogeologicalsurvey.org
Colorado Oil & Gas Association: http://www.coga.org/
Colorado Oil & Gas Conservation Commission: http://cogcc.state.co.us
CSUR Canadian Society for Unconventional Resources: http://www.csur.com
East Texas Geological Society: http://www.easttexasgeo.com/
East Texas SPE: http://easttexas.spe.org/
U.S. Energy Information Administration: http://www.eia.gov
European Association of Geoscientists and Engineers: http://www.eage.org
Gas Technology Institute: http://www.gastechnology.org
Gulf Coast Association of Geological Societies: http://www.gcags.org/
Jonah Interagency Office: http://www.wy.blm.gov/jio-papo/jio
Louisiana Department of Natural Resources: http://dnr.louisiana.gov/
Louisiana Geological Survey: http://www.lgs.lsu.edu/
Louisiana Mid-Continent Oil and Gas Association: http://www.lmoga.com/
Natural Resources Canada: http://www.nrcan.gc.ca/home#
Petroleum Association of Wyoming: http://www.pawyo.org/
PTAC Petroleum Technology Alliance Canada: http://www.ptac.org/
PTTC Regions: http://www.pttc.org/
PTTC Petroleum Technology Transfer Council Rocky Mountain Region: http://pttc.mines.edu/
Railroad Commission of Texas: http://www.rrc.state.tx.us/
Region 8 EPA Environmental Protection Agency: http://www.epa.gov/region8/
Rocky Mountain Association of Geologists: http://www.rmag.org

Texas Independent Producers and Royalty Owners Association: http://www.tipro.org/
U.S. Dept. of Energy Office of Scientific and Technical Information: http://www.osti.gov/
University of Wyoming Department of Geology & Geophysics: http://www.uwyo.edu/geolgeophys/
Wyoming BLM: http://www.blm.gov/wy/st/en.html
Wyoming Department of Environmental Quality: http://deq.wyoming.gov/
Wyoming Geological Association: http://www.wyogeo.org/
Wyoming Oil and Gas Conservation Commission: http://wogcc.state.wy.us/
Wyoming State Geological Survey: http://www.wsgs.uwyo.edu/