EMD Tight Gas Sands Committee

2015 EMD Tight Gas Sands Committee Mid-Year Report

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Vice-Chairs:

- **Shar Anderson Vice-Chair: Government,** Alberta Geological Survey/Alberta Energy Regulator

Advisory Group:

Special Consultants to the Tight Gas Sands Committee:

COMMITTEE ACTIVITIES

The Tight Gas Sands Committee is currently working with the Shale Gas Committee to define tight gas/oil and shale gas/oil. With clear definitions in place, the committees will evaluate the necessity of changing committee names and/or reallocating reservoirs to different committees.

We are currently looking at creating a new advisory group for the Tight Gas Sands Committee. All of the tight gas advisors on the committee, prior to our appointment, have declined to be included on the present committee. Advisors provide updates on the commodity activities in their region of work or interest. Anyone that may be interested, or knows anyone that may be interested, please contact Dean Rokosh or Shar Anderson.

EXECUTIVE SUMMARY

Tight gas sands are an unconventional hydrocarbon resource contained in low permeability (millidarcy to microdarcies range) and low porosity sandstone reservoirs. Tight gas sands are historically a dry gas resource, but low gas prices have compelled companies toward resources containing more liquids (oil or natural gas liquids).

Tight gas sands exploration and development appears to be declining, particularly since the shale gas boom accelerated around 2008. Many factors contribute to a decrease in interest for tight gas sands including changes in classifying reservoirs. New reservoir classifications—such as shale, hybrid and halo reservoirs—begin drawing distinctions between specific reservoirs that may over-lap the definition of a tight reservoir. 'Hybrid' shales are tight reservoirs containing a combination of migrated and self-sourced hydrocarbons; 'halo' or 'fringe' reservoirs are located on the fringes of conventional reservoirs and may include tight sand reservoirs. Producing hydrocarbons economically from these reservoirs requires technology to artificially enhance the permeability by fracturing and/or acidizing the formation. In addition, it is more profitable if the reservoir contains liquids as well as gas, based on today's market conditions.

The United States Energy Information Administration (EIA) estimates 310 trillion cubic feet (Tcf) (8.8 trillion cubic meters (Tcm)) of tight gas is technically recoverable in the United States. This represents about 17% of the total recoverable gas worldwide— > 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, Australia, China, and the Ukraine. McGlade et al. (2012) use prior publications to 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 play characteristics and activities in the United States, China and Canada. Some of the successful plays are commingled with fringe deposits surrounding conventional oil and gas plays, including liquids-rich gas from organic-rich, fine-grained, mixed-bed lithologies. A continuum of play-types clearly exists, from fringe conventional oil and gas to unconventional tight-gas sands to unconventional tight-shale gas. The distinction between these various hydrocarbon commodities will become less clear as development of these plays continue to evolve.

STATUS OF U.S. TIGHT GAS SANDS ACTIVITIES

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). Below is a summary of the more notable tight gas sands plays in the United States.

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

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 porosity ranging from 6-10%, absolute permeability from 1 microdarcy to 1 millidarcy, and water saturation 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 to 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 recovery (EURs) per well ranges from 1 to 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 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. It is estimated that 67% of the original gas in

place (OGIP) can be recovered using 10-acre (4-ha) spacing and 77% at 5-acre (2-ha) spacing. Initial well rates range from 1.3 to 6.1 MMcfd with EURs ranging from 1.5 to 5.7 Bcf per well.
As of 2013, there were 1876 gas wells, 73 dry holes or suspended wells (likely plugged), and 112 permitted locations or actively/completing wells in the Jonah field. 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.

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 down space 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.

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 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.

STATUS OF INTERNATIONAL TIGHT GAS SANDS ACTIVITIES

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. Below we summarize some of the more notable tight gas sand and tight oil plays in other countries.

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. A recovery of only 17% of the pools has been accomplished using conventional vertical drilling and completion strategies, 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 producing from by-passed pay, and by new development on the fringe of the conventional pools. Cardium reservoirs typically occur at depths between 3,937-9,186 feet (1200-2800 m) and mainly produce light oil with varying amounts of dissolved gas in the south, 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 play has had a sharp increase in horizontal play activity beginning in 2009, initially largely focused on the Pembina and Garrington fields of central Alberta. More recently, the drilling has dropped off considerably. 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, equally 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, a frac density of 18 frac stages per 4,593 foot (1400 m) horizontal well was more common with a switch from oil-based to water-based fracturing.

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

Drilling for Nikanassin dry gas has dropped off significantly in the last few years. Development of the Nikanassin has been within tight dry 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 up-hole 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 upper Montney in Alberta is a tight deposit that represents stacked distal shoreface/delta fringe and shelf sandstone and siltstone packages which have an aggregate thickness up to 512 feet (156 m). 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). Porosity in the reservoirs typically range from less than 3% to about 10%, with millidarcy permeability. Initial development in 2005 in northeastern British Columbia in more shale-dominated strata used several stages of hydraulic fractures first in vertical wells, now being developed solely by horizontal wells, with average initial flow rates of more than 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. 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 Tight Gas Sands

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.

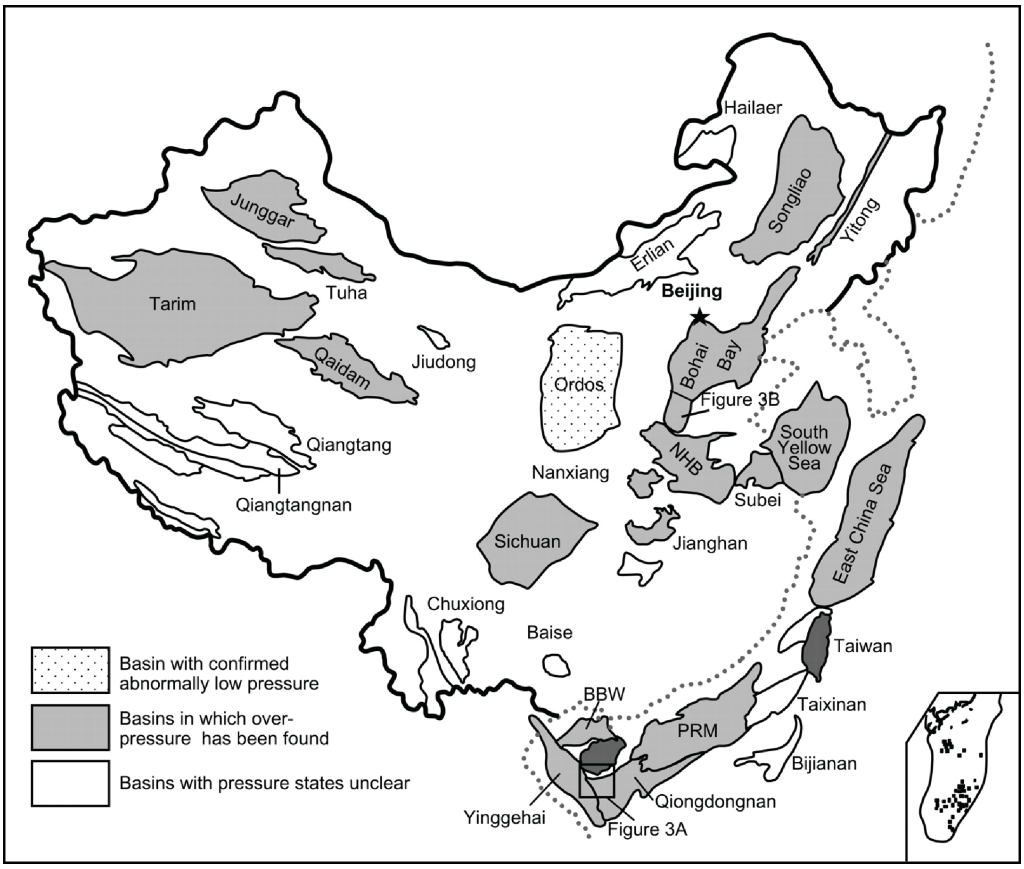

Figure 4. Location of China's major sedimentary basins (Hao et al 2007).

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 km2, 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 Songliao 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.

Other Areas of the World

There are tight deposits in many other areas of the world and our objective for the remainder of this fiscal year and next year is to fill the Advisory Board and gain knowledge on activity outside of North America. Furthermore, advice and information is required to update activity in some areas of North America.

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