EMD Shale Gas and Liquids Committee Annual Report, FY 2012

Neil S. Fishman, Chair

April 5, 2012

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INTRODUCTION

It is a pleasure to present this Annual Report from the recently renamed EMD Shale Gas and Liquids Committee. This report contains information about specific shales across the U.S., Canada, Europe, and China from which hydrocarbons are currently being produced or shales that are of interest for hydrocarbon exploitation. The inclusion in this report of shales from which any hydrocarbon is produced reflects the expanded mission of the EMD Shale Gas and Liquids Committee to serve as a single point of access to

technical information on shales regardless of the hydrocarbons produced from them (e.g., gas, oil, condensate). Given the intense interest in shales as "unconventional" hydrocarbon reservoirs, this report contains information available at the time of its compilation, and the reader is advised to use links provided herein to remain as up-to-date as possible.

This report is organized so that the reader can examine contributions from members of the EMD Shale Gas and Liquids Committee on various shales in the United States (presented in alphabetical order by shale name or region), Canada, Europe and China. Additional sections of the report include Valuable Links, Additional Sources of Information, and a Gas Shales and Shale Oil Calendar.

The leaders of this committee are interested in your feedback. Please feel free to contact Neil Fishman (nfishman@hess.com) with your comments and suggestions.

Antrim Shale (Devonian), Michigan Basin, U.S.

By Dr. William B. Harrison, III (Western Michigan University)

The Michigan Basin Antrim Shale play is currently 25 years old, having begun the modern phase of development in 1987. The total number of producing wells drilled in the play through end of December, 2011 is approximately 11,494 with about 9,817 still online.

Total cumulative gas production reached 3.102 TCF by the end of 2011. Michigan Antrim production is reported by project rather than by individual well or lease. Projects may be only a few wells or more than 70 wells. There were 792 separate projects at the end of December, 2011. Cumulative production for 2011 was 113,563,623 MCF of gas. That was a 5.5% decline from 2010.

There were 30 operators with production at the end of 2011. There were 9,817 wells online at the end 2011. There were 111 new wells drilled in 2009, only 58 in 2010 and 39 in 2011. That is a 48% decrease in wells drilled from 2009 to 2010 and continuing drop of 33% in new wells completed in 2011. Overall drilling activity in Michigan was down 16% in 2011 compared to 2010. Most of the production comes from a few operators. The top 10 operators produced 82.4% of the total Antrim gas in 2011.

Although some wells can initially produce up to 500 MCF/day, generally wells settle at less than 100 MCF/day. Play wide average production at the end of 2011 was 31 MCF/day per well. Many Michigan Antrim wells begin with high water production and begin to increase gas production as the water is pumped off. Water production generally continues throughout the project life, although it usually declines through time. Play wide gas to water production ratio reached almost 3 MCF/BBL in 1998, in 2004 it was 2.21 MCF/BBL, the 2009 ratio is 1.56 MCF/BB and at the end of 2011 the ratio was 1.57 MCF/BBL. Play wide water ratios have begun to decrease relative to gas production as old wells are dewatered and very few new wells are being drilled.

CO_2 is also an issue in the produced Antrim gas that is mostly of biogenic origin. Most wells begin with very low amounts of CO_2 in the produced gas; however, the percentage of CO_2 increases through time. Some projects that have a long production history may now exceed 30% CO_2 in the produced gas. The play wide average was just over 12.4% CO_2 in 2008.

Wells produce from depths as shallow as 350 feet to just over 3,000 feet, although the vast majority of wells are completed from 1,000 to 2,500 feet deep. Wells are typically drilled with water and an attempt is made to keep the well in balance or slightly under-balanced. Wells are fraced with water and sand. Some wells are fraced using nitrogen or foam.

Production and well data is available online at the Michigan Public Service Commission at http://www.cis.state.mi.us/mpsc/gas/prodrpts.htm

Various kinds of oil and gas information is also available at the Michigan Office of Geological Survey site at http://www.michigan.gov/deq/0,1607,7-135-3311_4111_4231---,00.html

Cores, samples and other kinds of data are available at the Michigan Geological Repository for Research and Education at Western Michigan University. That website is http://wst023.west.wmich.edu/MGRRE%20Website/mgrre.html

Top 10 Operators:
Chevron Michigan LLC
Linn Operating, Inc.
Terra Energy Ltd
Breitburn Operating Limited Partnership
Muskegon Development Co.
Ward Lake Energy
Trendwell Energy Corp.
Jordan Development Co. LLC
Delta Oil Co. Inc.
Merit Energy Co.

Significant Trends – Production continues to decline even as the total number of active wells which increases. Daily gas production per well declined by 5.5% in 2011. However, daily water production per well decreased 7.8% in 2011 compared to the same period in 2010. The numbers of horizontal completions still represent less than 5% of total wells.

Issues – None

Legislation – None

Bakken Formation (Upper Devonian-Lower Mississippian), Williston Basin, U.S.

By Julie LeFever and Stephan Nordeng (North Dakota Geological Survey)

In 2008, the United States Geological Survey (USGS) used a standardized assessment regime that concluded that the Bakken Petroleum System in the entire Williston Basin contains an undiscovered 3.65 BBbls of oil, 1.85 trillion cubic feet of natural gas, and 148 million barrels of natural gas liquids that are technically recoverable with current technologies (Pollastro and others, 2008). The North Dakota Department of Mineral Resources (Bohrer and others, 2008) estimates that there are 2.3 BBbls of recoverable oil in place (OIP) within the North Dakota portion of the Williston Basin.

Petroleum within the Bakken is properly considered a continuous petroleum accumulation for the following reasons:

1. The Bakken is a regionally extensive, organic-rich source rock;
2. The Bakken has a burial history that has resulted in temperatures sufficient to convert organic matter into petroleum;
3. The overlying and underlying rocks are sufficiently thick, widespread and impermeable so as to isolate the accumulation;
4. There are overlying and/or underlying rocks that are sufficiently permeable and porous to accumulate economic quantities of oil or gas. (i.e. Bakken Petroleum System which includes the middle member of the Bakken Formation, Three Forks Formation, and the Lodgepole Formation; Price and LeFever, 1994); and,
5. Abnormally high formation pressures indicate that petroleum has been injected into these rocks and that the "charge" has not escaped through permeable zones, fractures or faults.

Petroleum accumulations, such as the Bakken, cover large areas with poorly defined margins. Virtually every study of the Bakken Petroleum System has concludes that the resource is enormous with total in place volumes of oil that are in the range of 10s to 100s of billions of barrels.

Bakken development spans almost 60 years and is witness to several important advances in drilling, completion and stimulation techniques. Each of these advances has significantly increased the productive acreage and value of the formation. Of particular importance are the dual developments of precise directional drilling technologies that result in the modern horizontal well bore and advances in well stimulation technologies. The significance of this is that artificially fractured horizontal well bores open up much larger sections of an oil-bearing formation and by virtue of increasing the collection capacity of a single well allows for larger volumes of oil to be produced. This is especially important when attempting to produce oil from formations such as the Bakken and Three Forks in which matrix permeabilities are in the microdarcy range.

Oil production from the Bakken was first established on the Antelope Anticline in 1953 when Stanolind Oil and Gas Corp. drilled and completed the #1 Woodrow Starr (SWSE Sec. 21, T152N, R.94W). The well was drilled to a total depth of 12,460 feet, plugged back and cased to 10,675 feet. This well was perforated between 10,528 and 10,556 feet depth and stimulated with 4,900 pounds of sand and 120 bbls of crude oil. The well came on line on December 6, 1953 with an initial production (IP) of 536 barrels per day of 44° API gravity oil and 770 cubic feet of gas per barrel. Casing problems in the #1 Woodrow Starr forced the well to be plugged and abandoned after 55 months of production during which 279,254 barrels of oil and 108 barrels of water were produced. The majority of the 44 wells in Antelope Field were drilled during the 1950's and 1960's. Oil production from the first wells in the Antelope Field is restricted to structurally induced fracture systems. The recognition that pervasive fracture systems are a necessary component of a successful Bakken well became the dominant exploration model until the mid-1990s.

Between 1960 and 1975 production outside of the Antelope Field was established in a few wells. The Government 41X-5-1 well drilled by Shell Oil in 1961 in Billings County (NENE Sec. 5, T143N, R101W) demonstrated that oil production outside of the Antelope Field was possible. The Government 41X-5-1 was drilled to a total depth of 13,018 ft and was plugged back to a depth of 10,738 ft. A drill stem test of the lower Lodgepole, Bakken and Three Forks Formations recovered gas and heavily oil cut mud with shut in pressures of about 6,600 pounds per square inch (psi). The well was perforated in the upper Bakken shale between 10,682 and 10,692 ft depth and in the upper Three Forks between 10,705 and 10,715 ft depth. 4,000 gallons of acid were used to stimulate the well. The initial production rate was reported to be 136 barrels of 43.4 ^{o} API gravity oil with a gas to oil ratio (GOR) of 1230 cubic feet of gas per barrel of oil. Seven months later the well was hydrofraced with 20,000 gallons of acid and 9,000 pounds of sand. Production following stimulation was reported to be 48 bopd. The well was abandoned in August of 1964 after producing 57,840 bbls of oil.

Late in the 1970's, additional vertical production developed along the southwestern depositional limit of the Bakken Formation. Along this trend, known as the “Bakken Fairway”, only the upper Bakken is present. The “Fairway” is some 200 miles long and 30 miles wide and lies along the updip feather edge of the upper shale. At least 26 fields were established along structural features over which the Bakken thinned and apparently fractured.

Drilling methods in the Bakken Fairway changed significantly in 1987 after Meridian Oil, Inc. drilled the first horizontal Bakken well. Meridian drilled and completed a vertical well in March 1986 for 217 BOPD. (#21-11 MOI-Elkhorn; NWSE Sec. 11, T143N, R102W). This well established the presence of a fracture trend that was exploited with the first horizontal well into the Bakken. A 2,600 ft. long lateral was drilled from the vertical well into an 8-foot-thick section of the upper Bakken shale. Initial production from the lateral was 258 BOPD and 299 MCF of gas (LeFever, 1991). Horizontal drilling along the Bakken Fairway peaked in 1992 before slowing late in the 1990s and essentially ending by 2000 (LeFever, 2000).

Development of the Elm Coulee Field in 1996 resulted from the first significant oil production from the middle member of the Bakken Formation. Production from the middle member was established in the Kelly/Prospector #2-33 Albin FLB following an unsuccessful test of the deeper Birdbear (Nisku) Formation. Subsequent porosity mapping outlined a northwest-southeast trending stratigraphic interval containing an unusually thick dolomitized carbonate shoal complex within the middle member. Horizontal wells drilled through this shoal complex in 2000 resulted in the discovery of the giant Elm Coulee Field in eastern Montana. As with the previous Bakken producing fields, production at Elm Coulee depends on fracturing but in this case the productive fractures are found in the middle member of the formation. Since its discovery, more than 600 horizontal wells have been drilled in the 450-square-mile field from which more than 94 MMBbls of oil have been recovered. The productive portions of the reservoir contains between 3 and 9 percent porosity with an average permeability of 0.04 md. A pressure gradient in the Bakken of 0.53 psi/ft indicates that the reservoir is overpressured. Laterals are routinely stimulated by a variety of sand-, gel- and water-fracturing methods. Initial production from these wells is between 200 and 1900 BOPD (Sonnenberg and Pramudito, 2009).

The Bakken middle member play moved across the line into North Dakota when Michael Johnson noted that wireline logs of the Bakken Formation along the eastern limb of the Williston Basin in Mountrail County, North Dakota resembled those from Elm Coulee. Even though the kerogen within the Bakken shales appeared immature and thus might not be generating oil, free oil in DSTs and some minor Bakken production encouraged Johnson to pursue a Bakken play in Mountrail County (Durham, 2009). In 2005, EOG Resources demonstrated with the #1-24H Nelson-Farms (SESE Sec. 24, T156N, R92W) that horizontal drilling coupled with large scale hydraulic fracture stimulation of the middle Bakken Formation could successfully tap significant oil reserves along the eastern flank of the Williston Basin. In the following year, EOG Resources drilled the #1-36 Parshall and #2-36 Parshall which resulted in wells with initial production rates in excess of 500 BOPD. Subsequent horizontal drilling in the Parshall Field coupled with staged fracture stimulation has resulted in several wells with IPs in excess of 1,000 BOPD. Currently the field is producing an average of about a 1.3 MMBbls of oil per month from 165 wells. Sanish Field, adjacent to Parshall, is producing 670 MBbls of oil per month from 95 wells.

The North Dakota portion of the Williston Basin is extremely active with 196 rigs running which is up from 104 rigs. Currently the top 10 producers in the play are:

1. EOG Resources (314 wells up from 167 wells)
2. Hess Corporation (288 wells up from 141 wells)
3. Continental Resources, Inc. (283 wells up from 100 wells)
4. Marathon Oil Company (211 wells up from 133 wells)
5. Whiting Oil and Gas Corporation (197 wells up from 69 wells)
6. XTO Energy Inc. (142 wells up from 75 wells)
7. Burlington Resources Oil & Gas Company, LP.
8. Slawson Exploration Company, Inc. (119 wells up from 33 wells)
9. Petro-Hunt, LLC (68 wells up from 30 wells)
10. Oxy USA Inc. (65 wells up from 29 wells)

Additional Information:
North Dakota Geological Survey Website: https://www.dmr.nd.gov/ndgs/bakken/bakkenthree.asp

Recent Publications:

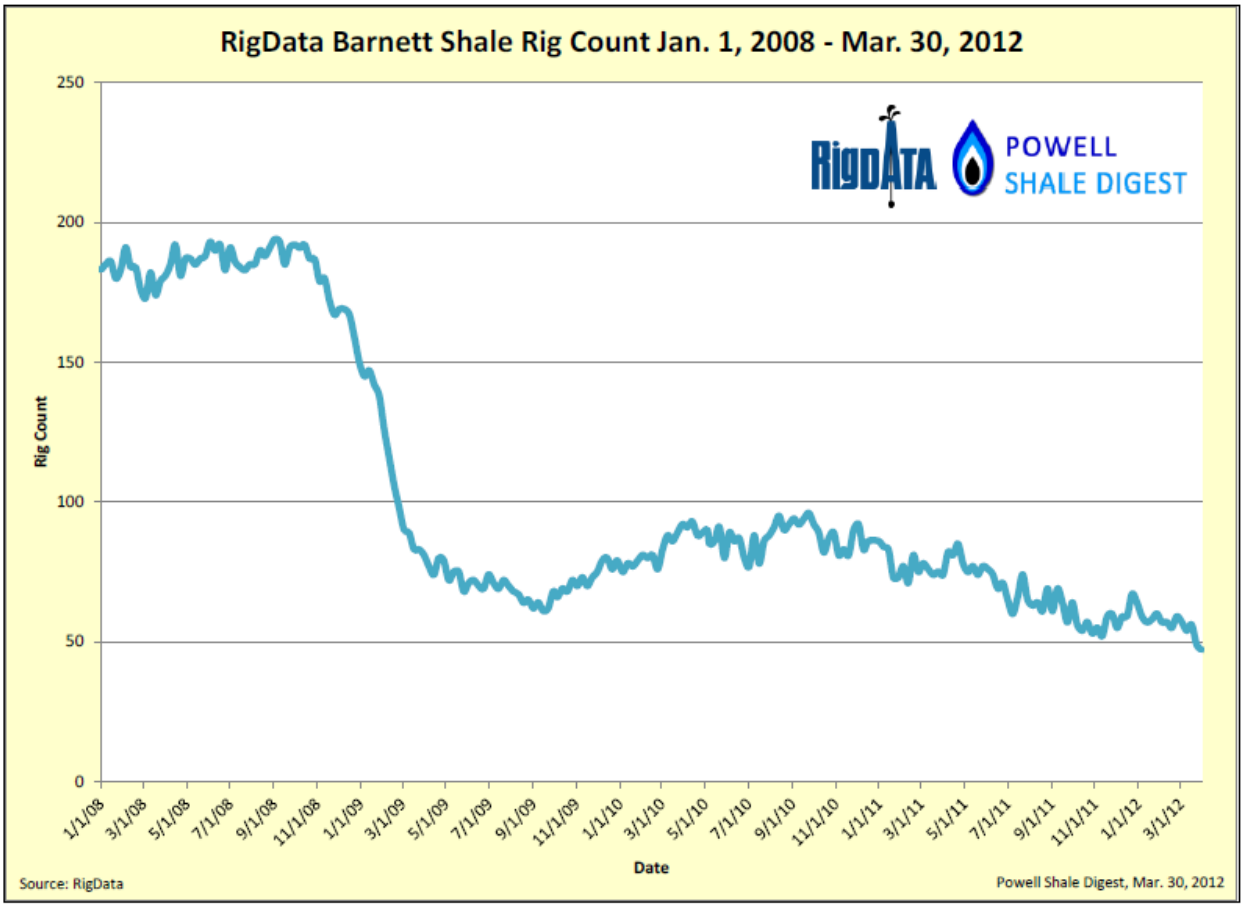
John W. Robinson, Julie A. LeFever, Stephanie B. Gaswirth, 2011, The Bakken-Three Forks petroleum system in the Williston Basin: The Rocky Mountain Association of Geologists.

Julie A. LeFever, Richard D. LeFever, Stephan H. Nordeng, 2011, Cyclical sedimentation patterns of the Bakken Formation, North Dakota: Geological Investigation No. 137.
Stephan H. Nordeng, Julie A. LeFever, Fred J. Anderson, Marron Bingle-Davis, and Eric H. Johnson, 2010, An examination of the factors that impact oil production from the middle member of the Bakken Formation in Mountrail County, North Dakota: Report of Investigation No. 109
Geologic Investigations No. 93
Sheet 1 - Stephan H. Nordeng and LeFever, J.A., 2010, Structural Transect of the Sanish and Parshall Fields, Bakken Formation, Mountrail County, North Dakota
Sheet 2 - Julie A. LeFever and Nordeng, S.H., 2010, Stratigraphic Transect of the Sanish and Parshall Fields, Bakken Formation, Mountrail County, North Dakota

Barnett Shale (Mississippian), Fort Worth Basin, U.S.

By Kent Bowker (Bowker Petroleum, LLC)

The rig count in the Barnett has slowly dropped in the past several years to 47 operating rigs in 18 counties. Tarrant County has the most rigs at 10 (Tarrant County is also home to most of the top-10 producing wells in the play, as noted in the Powell Shale Digest - www.shaledigest.com). Devon continues to be the most active operator in the play. As of March 5, 2012, there were 15,731 total wells producing from the Barnett (http://www.rrc.state.tx.us/data/fielddata/barnettshale.pdf).

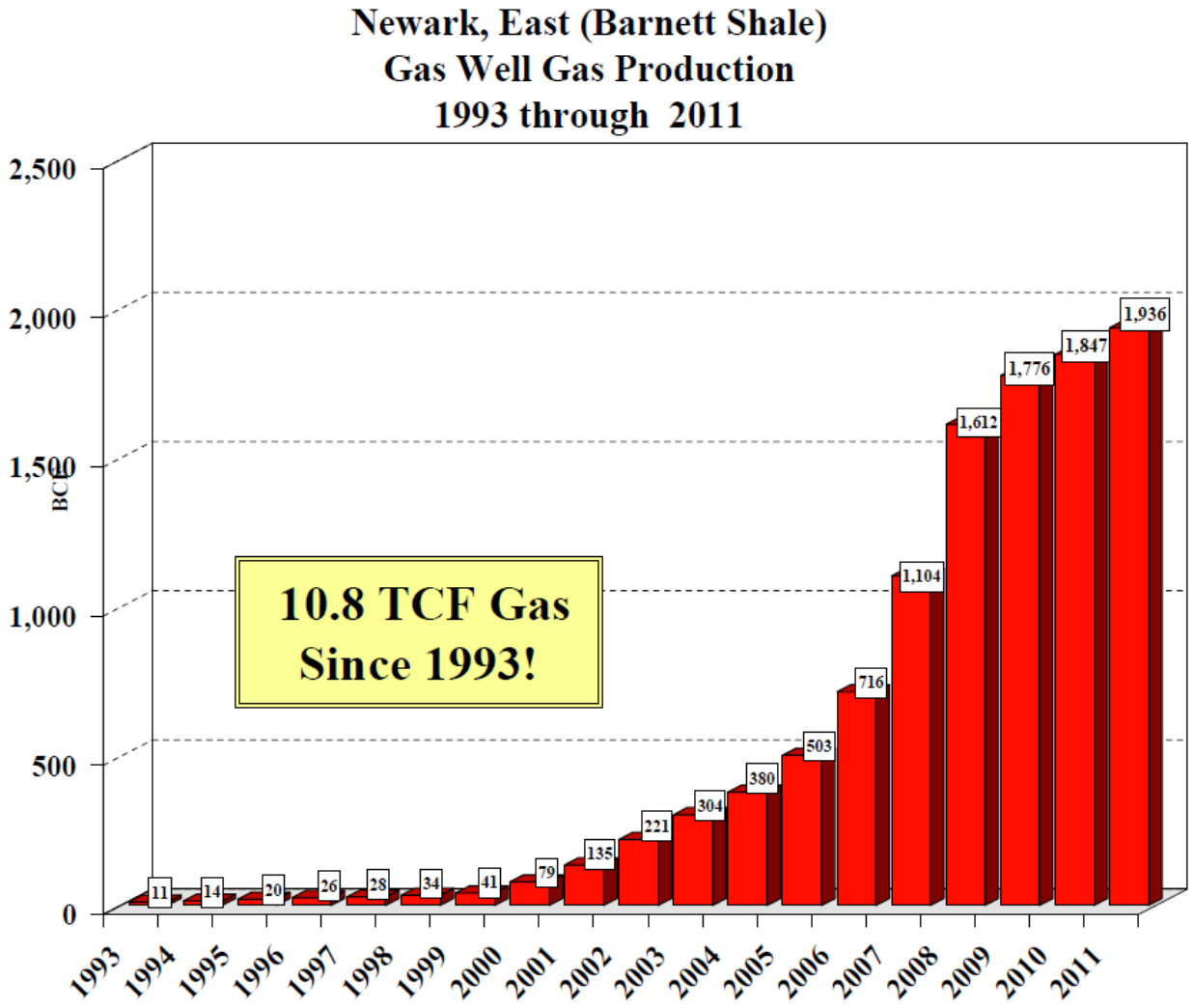


(used with permission of Gene Powell)

All time peak gas production was reached in May, 2011 at 5.87 BCF/D, with peak oil/condensate production reached in July, 2011 at 29,736 B/D. Oil/condensate production in the Barnett was 10,000 B/D in July 2010, the large increase certainly due to the huge price differential between gas and liquid hydrocarbons. These production data appear to refute the contention that production from shale plays will decline quickly once drilling activity declines.

The top ten gas wells (in terms of gross cumulative production) in the Barnett play are all located in Tarrant County (Fort Worth is the county seat), with the best well in the play (API 42-439-31164) having a cumulative production of 5.6 BCFG. Also in Tarrant County, Devon recently drilled the 31st horizontal Barnett well off a single drilling pad, with plans to ultimately drill 35 wells off the pad.

Gas production continued to grow in 2011, albeit at a much lower pace than in the past several years. This is in spite of the steady drop in the rig count in the play over the period. In July, 2011, the Barnett reached a milestone: 10 TCF of total gas production from its initial production in June 1982 (though Barnett production was miniscule until mid-1999).



(graph from http://www.rrc.state.tx.us/barnettshale/NewarkEastField_1993-2011.pdf)

As gas prices continue to deteriorate, it will be interesting to see how operators in the largest gas field in Texas respond.

Chattanooga Shale, (Devonian-Mississippian), various basins, U.S.

By Kent Bowker (Bowker Petroleum, LLC)

Northern Shelf, Black Warrior Basin, Alabama:

There has been no activity on GeoMet's Chattanooga Shale program in Blount and Cullman counties in north-central Alabama (north shallow shelf of the Black Warrior Basin) since our last report. A combination of poor production results and weak gas prices seem to have doomed the project.

Chattanooga Shale, North-Central Tennessee (Appalachian Basin):

CONSOL Energy (formally CNX Gas) has apparently abandoned their Chattanooga Shale program in Tennessee. Atlas Energy, LP still maintains 120,000-acre position in eastern Tennessee, but has no immediate plans to develop the Chattanooga on this block.

Eagle Ford Group (Cretaceous), Gulf Coast Basin, U.S.

By Russell Dubiel (U.S. Geological Survey)

The Cretaceous (Cenomanian-Turonian) Eagle Ford Shale of southwest Texas continues to produce thermogenic gas, oil and condensate. The Eagle Ford play trends across Texas from the area of the Maverick Basin, northeast into the Karnes Trough. (Fig. 3), where it is variably a target for dry gas, wet gas/condensate, or oil. The wells that have been completed display a rapid decline in production similar to those in other shale plays. As for shale oil wells, recently drilled wells have shown initial production rates of several hundreds of BOPD. As of March 15, 2012, there were 3,649 permitted and 1,532 completed Eagle Ford oil and gas wells (Railroad Commission of Texas, http://www.rrc.state.tx.us/eagleford/eagleford-oilproduction.pdf. accessed March, 2012). The trend occurs at an average depth of 11,000 feet, and it is over-pressured.

As with the Barnett and Haynesville Shales, the Eagle Ford is a viable target for hydrocarbon exploitation because of advances in the application of horizontal drilling and fracturing procedures. Mineralogy of the Eagle Ford is somewhat different than other gas shales, however, in that where it is being explored, the Eagle Ford contains significant marl beds. Most operators are drilling horizontal well laterals of 3,500 to 5,000 feet and are fracing the wells with slick water or acid in at least 10 different stages. For more information on Eagle Ford production, please refer to the Texas Railroad Commission web link at http://www.rrc.state.tx.us/eagleford/.

Recent activity and success in the Eagle Ford in Texas has generated renewed interest in the laterally equivalent Cenomanian-Turonian Tuscaloosa Marine Shale in eastern Louisiana and southern Mississippi. Initial exploration in the Tuscaloosa Marine Shale in the 1970's has been followed by minimal exploration and production in the 1980's, 1990's and early 2000's. In 2010 and 2011, several companies began significant leasing in eastern Louisiana and southern Mississippi. Over the last eighteen months, those companies have begun exploratory and initial development drilling for the Tuscaloosa Marine Shale, based in part on the current higher price for oil, the recent horizontal drilling success in the Eagle Ford in Texas, and a historical record of hydrocarbon generation and proven, but minimal, production from the unit. The trend averages about 12,000 to 15,000 ft and is overpressured. During 2011 and the first quarter of 2012, several companies have drilled successful horizontal wells; reported IPs are encouraging, but currently only

minimal yearly production data is available to evaluate the play's future success. A summary of play history and a discussion of recent leasing and exploration trends can be found in the August 2011 issue of the AAPG Explorer: http://www.aapg.org/explorer/2011/08aug/tuscaloosa0811.cfm

Fayetteville Shale (Mississippian), Arkoma Basin, U.S.

By Peng Li (Arkansas Geological Survey)

The Upper Mississippian Fayetteville Shale play is the current focus of a regional shale-gas exploration and development program within the central and eastern Arkoma Basin of Arkansas. Approximately 2.5 million acres have been leased in the Fayetteville Shale gas play (Figure 1). Production of thermogenic gas from the Fayetteville began in 2004 and continues to the present.

Early estimates have indicated that there are over 40 tcf of gas reserves in the Fayetteville Shale, although recent studies indicate that the Fayetteville contains an estimated mean undiscovered volume of 13.2 TCF of technically recoverable gas from the formation (Houseknecht et al., 2010). Also, smaller proved reserves of 9.07 TCF were reported to the Fayetteville Shale by the U.S. Energy Information Administration (U.S. EIA) in 2010 (Summary: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Proved Reserves 2009, U.S. EIA), which is based on data provided by operators on Form EIA-23. Estimated ultimate recovery (EUR) for a typical horizontal Fayetteville gas well is 2.9 bcf. Estimated cumulative production of gas from the Fayetteville Shale as of end of 2011 has totaled 2,622,277,636 mcf from 3,859 wells. Annual production of Fayetteville Shale for 2011 is 943,573,332 mcf from 3,793 producing wells, about 20% increase compared with 2010 production. Initial production rates of horizontal wells have recently averaged about 3,136 mcf/day. For more Fayetteville Shale production information, please refer to the Arkansas Oil and Gas Commission (AOGC) web link at http://www.aogc.state.ar.us/Fayprodinfo.htm.

Fayetteville Shale reports from the AOGC have noted well increases from 24 in 2004, 33 in 2005, 129 in 2006, 428 in 2007, 587 in 2008, 839 in 2009, and 874 in 2010. The number of new wells drilled in 2011 slightly declined to 829. As of March 2012, there are a total of 3,874 producing gas wells in the Fayetteville Shale play. Most Fayetteville Shale wells are drilled horizontally and have been fracture stimulated using slickwater or cross-linked gel fluids. Horizontal lateral lengths are continually increasing in Fayetteville Shale wells. Horizontal wells drilled from 2010 to 2012 averaged 5,600 feet in lateral length with some wells up to 8,000 feet. Fayetteville Shale gas production generally ranges over a depth between 1,500 to 6,500 feet. The thickness of Fayetteville Shale varies from 50 feet in the western portion of the Arkoma Basin of Arkansas (fairway area) to 550 feet in the central and eastern regions (primary producing area).

Southwestern Energy has been the largest player since 2004 when production started. It holds approximately 875,000 net acres in the play area and estimates 11 tcf of recoverable gas for its acreage position. Second-largest producer BHP Billiton Petroleum, which acquired all of Chesapeake Energy Corporation's interests in the Fayetteville Shale, leases about 487,000 net acres with about 9 tcf of recoverable gas. Dated back to 2008, Chesapeake already sold approximately a 25% interest in Fayetteville assets to BP for $1.9 billion. Petrohawk Energy, which includes subsidiaries of One Tec Operating LLC and KCS Resource Inc., announced on December 23, 2010 that it has completed the sale of its natural gas assets in the Fayetteville Shale to another active Fayetteville Shale producer XTO Energy Inc., a subsidiary of ExxonMobil, for $575 million. In addition, Petrohawk has entered into a definitive agreement with XTO Energy to sell its midstream assets in the Fayetteville Shale for $75 million. BHP Billiton announced on August 26, 2011 that it had completed its acquisition of Petrohawk Energy as a wholly owned subsidiary of BHP Billiton. Other operators involved with Fayetteville Shale exploration and development ventures

include: David H. Arrington Oil and Gas Inc., Storm Cat Energy (USA) Operating, SH Energy, L&L Energy, and Sedna Energy.

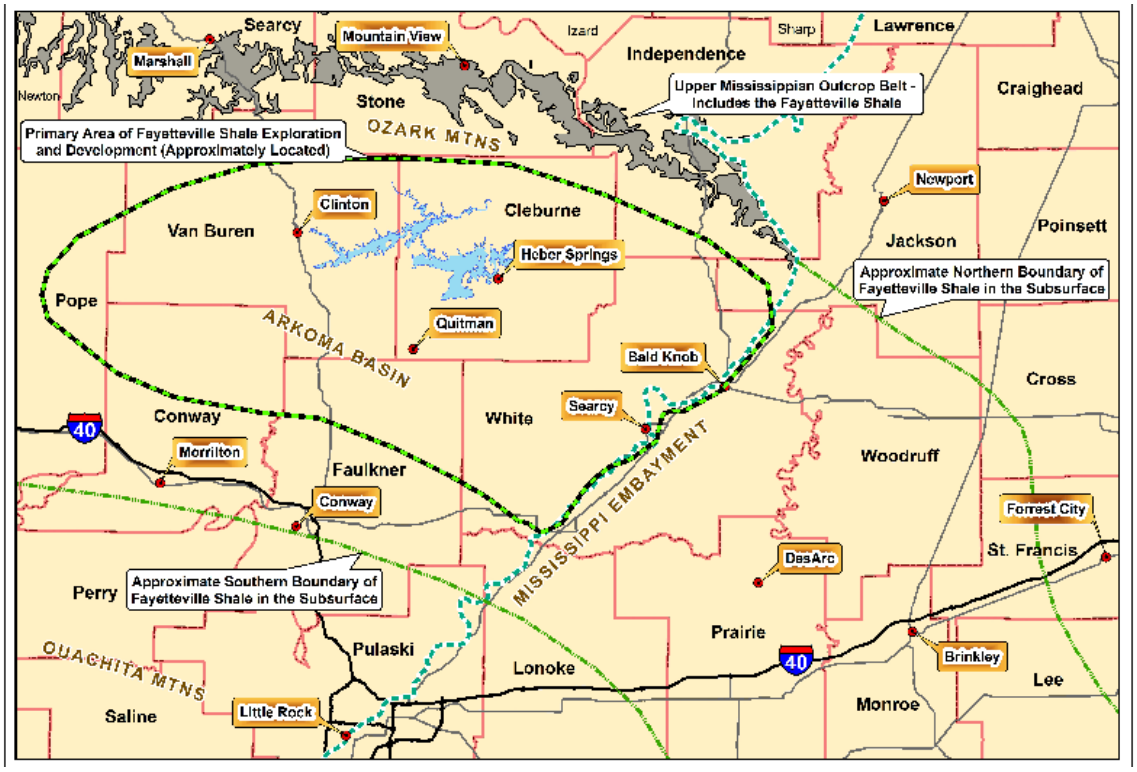


Figure 1. Primary area of the Fayetteville Shale exploration and development in Arkansas.

The top three operators of the Fayetteville gas shale play as of March 2012 based on numbers of producing wells are as follows (Figure 2):

1) SEECO Inc. (an exploration subsidiary of Southwestern Energy) (2344 wells)
2) BHP Billiton Petroleum (813 wells)
3) XTO Energy, Inc. (a subsidiary of ExxonMobil) (673 wells)

Two different maps are available that illustrate the location and types of wells located in the Fayetteville Shale producing area. Web links for the Fayetteville Shale maps and the associated federal and state agencies are listed below:

(1)The home page of the Arkansas Geological Survey (AGS) website is: http://www.geology.arkansas.gov/home/index.htm and the AGS Fayetteville Shale well location maps can be viewed at http://www.geology.arkansas.gov/home/fayetteville_play.htm. AGS updates these maps and associated well database (in Excel® format) online every two weeks.

(2) The home page of the U.S. Energy Information Administration (EIA) website is: http://www.eia.doe.gov/ and the EIA Fayetteville Shale map is available at http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm.

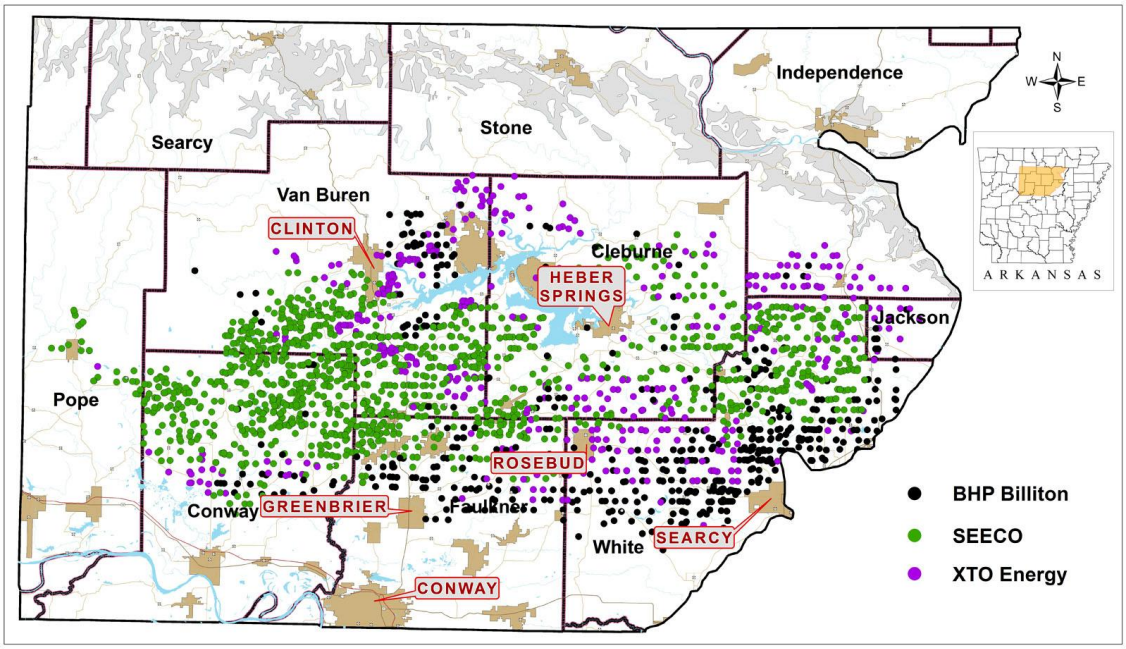


Figure 2. Location map of the Fayetteville Shale producing wells by top 3 operators as of March 2012.

Disposal of wastewater through injection wells has gradually mounted a concern in the Fayetteville Shale play area given thousands of area earthquakes, most too small to be felt, detected beneath an area near the towns of Guy and Greenbrier, Central Arkansas, since last fall. A recently discovered fault, the Guy-Greenbrier Fault, near the disposal wells, is nearly 7.5 miles long, which could theoretically generate a quake of around 6.0 in magnitude. In January 2011 AOGC imposed a six-month moratorium on new injection wells in the Fayetteville Shale production area to determine what relationship, if any, there is between the wastewater injection and the earthquakes. The quakes intensified during the last two weeks of February 2011, culminating with a 4.7-magnitude earthquake near Greenbrier on February 27, 2011, the most powerful reported seismic event in Arkansas in 35 years. AOGC held a special meeting on March 4, 2011 to issue an emergency order immediately shutting down all injection operations of two disposal wells through the last day of the regularly scheduled hearing in March 2011. At the March 2011 hearing, AOGC ordered the companies to continue the cessation of all injection operations of these two wells for a period of an additional sixty days. During the July 2011 hearing, the AOGC requested an immediate and permanent moratorium on any new or additional disposal wells or disposal well permits in the moratorium area (Figure 3). At the time of the hearing, there were four disposal wells within the moratorium area, including the two wells that were shut down since March 2011. The frequency of the quakes within the moratorium area saw a significant decrease, about 75%, since the cessation of the injection operation of the disposal wells. This, in turn, gave more evidence to confirm the relationship between the injection activities and the earthquakes. Geohazards geologists at the AGS that monitor the earthquakes in the state provide the relevant information to the public and the AOGC.

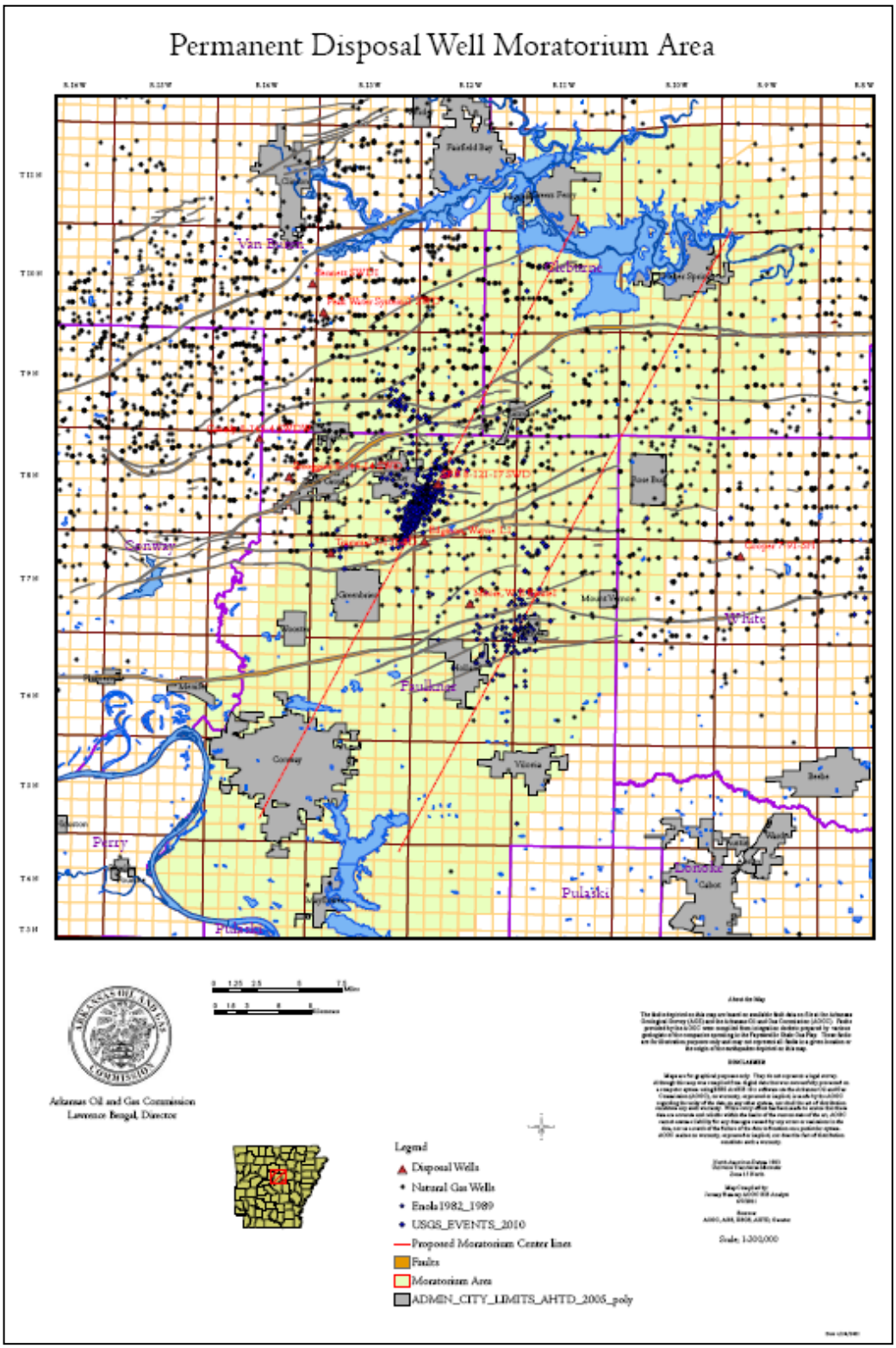


Figure 3. Moratorium area for the permanent disposal wells in the Fayetteville Shale Play, Arkansas (from the AOGC website).

Concerns about the effect of Fayetteville gas exploration and production on public heath, air, water and land are increasing with the spread of hydraulic fracturing technology that is utilized in well completions. Expanded production and potential environmental impacts have increased the need for additional regulations related to all aspects of exploration and production. Arkansas joins Wyoming as the only states that require the full disclosure of all chemical constituents in all frac fluids and additives on a well-by-well basis and the release of these reports to the public. The AOGC's Rule B-19 (available on the AOGC website), which also protects the trade secrets behind proprietary compounds, went into effect January 15, 2011. AOGC also issued a revised surface casing and production casing cementing requirements for all Fayetteville Shale wells. All operators of such wells since June 1, 2011 are required to set surface casing to a depth equal to 500 feet below the lowest ground surface elevation occurring within 1 mile of the proposed well, with a minimum of 1000 feet of surface casing to be set and cemented to surface. In addition, cement shall be circulated to the surface on all production casings, so as to isolate from all strata encountered in the wellbore above the Fayetteville Shale horizon.

AGS has completed two extensive geochemical research projects on the Fayetteville Shale and has provided this information to the oil and gas industry and the public to assist with exploration and development projects. These studies are available at the Arkansas Geological Survey as Information Circular 37 (Ratchford et. al., 2006) and Information Circular 40 (Li et al., 2010) and integrate surface and subsurface geologic information with organic geochemistry and thermal maturity data.

The AGS continues to partner with the petroleum industry to pursue additional Fayetteville Shale related research. Ongoing AGS research is focused on the chemistry and isotopic character of produced gases, mineralogy of the reservoir, and outcrop to basin modeling.

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Haynesville/Bossier Shale (Jurassic), Texas and Louisiana, U.S.

by Ursula Hammes (Bureau of Economic Geology, Austin, TX)

The Kimmeridgian Haynesville Shale spans more than 16 counties along the boundary of eastern Texas and western Louisiana. Basement structures and salt movement influenced carbonate and siliciclastic sedimentation associated with the opening of the Gulf of Mexico. The Haynesville shale is an organic- and carbonate-rich mudrock that was deposited in a deep, partly euxinic and anoxic basin during Kimmeridgian to early Tithonian time, related to a second-order transgression that deposited organic-rich black shales worldwide. The Haynesville basin was surrounded by carbonate shelves of the Smackover and Haynesville lime Louark sequence in the north and west. Several rivers supplied sand and mud from the northwest, north, and northeast into the basin. Haynesville mudrocks contain a spectrum of facies ranging from bioturbated calcareous mudstone, laminated calcareous mudstone, and silty peloidal siliceous mudstone, to unlaminated siliceous organic-rich mudstone (Fig. 1; Hammes and Frébourg, 2011). Framboidal to colloidal pyrite is variably present in the form of concretions, laminae, and individual framboids and replaces calcite cement and mollusk shells (Hammes et al., 2011). Haynesville reservoirs are characterized by

overpressuring, porosity averaging 8–12%, Sw of 20–30%, nano-darcy permeabilities, reservoir thickness of 200-300 ft (70–100m), and initial production ranging from 3 to 30 MMCFE/day (Fig. 1). Reservoir depth ranges from 9,000 to 14,000 ft (3000–4700 m), and lateral drilling distances are 3000– 5000 ft (1000–1700 m).

As with most deep shale-gas reservoirs low natural gas prices have been hurting economics. Therefore, companies are shifting to liquid-rich reservoirs. Haynesville operators have been reducing rigs by half since the high in 2010 in Texas and Louisiana because low gas prices are reducing the economic value of these deep Haynesville wells. One cost-saving drilling tool tried by Encana was to use LNG-powered shale drilling instead of Diesel that reduced fuel costs by 50% (Bloomberg news accessed). Gas production has therefore been declining since November 2011 (Fig.). However, Anadarko is one company that started to look at "liquids" in the predominantly northern part of the Haynesville. Liquids production almost doubled in November (Fig.). Additional information on the Haynesville can be found at the Louisiana Oil and Gas association (http://www.loga.la/haynesville-shale-news/, accessed November 3, 2011.

A B

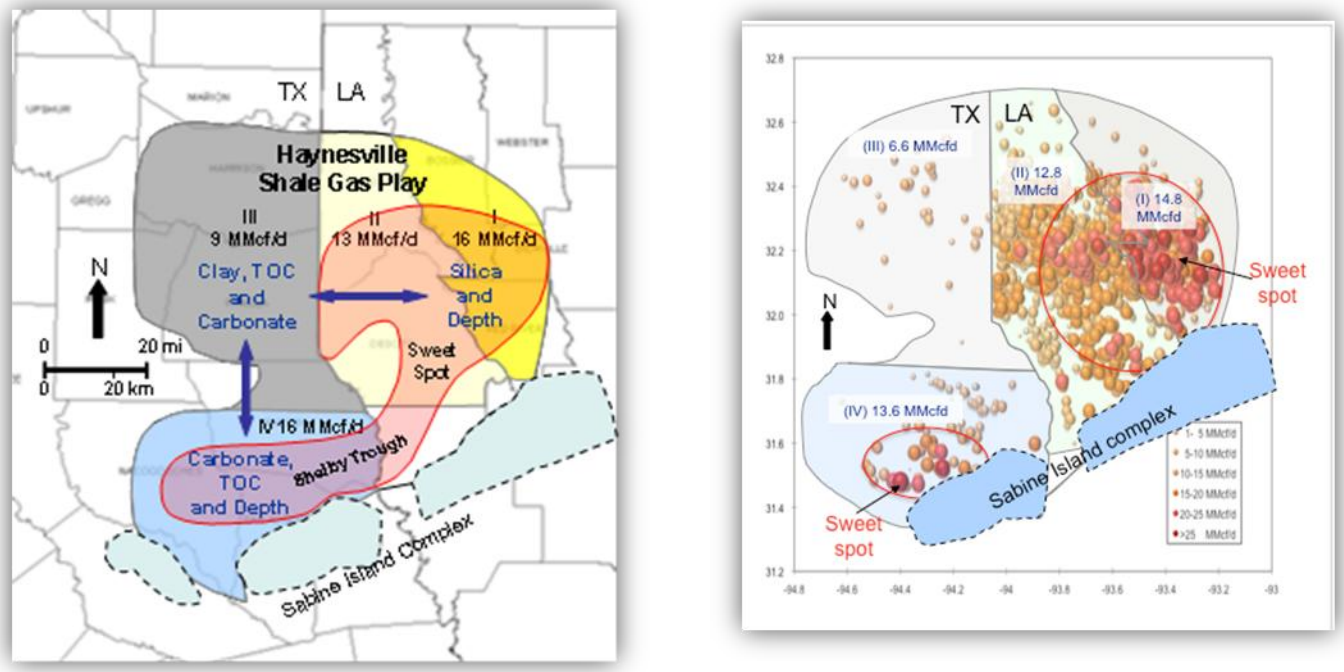

Figure 1: A. Initial potentials of four production areas and factors (mineralogy) affecting initial potential in the core area of the Haynesville play. B. Bubble map of initial potential for Haynesville wells. TX = Texas, LA = Louisiana. From Wang and Hammes (2010) and Wang et al. (in prep.).

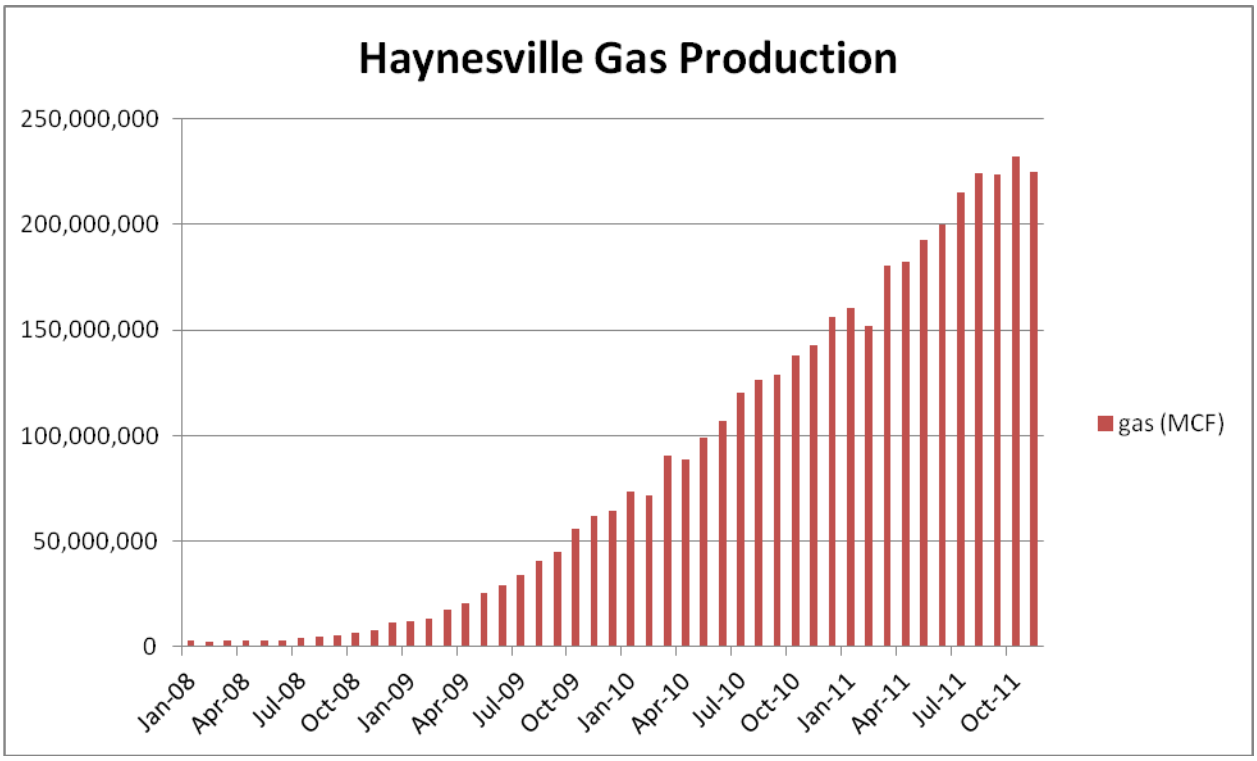

Figure 2: Cumulative production chart (MCF) for Haynesville Shale (data from IHS Enerdeq).

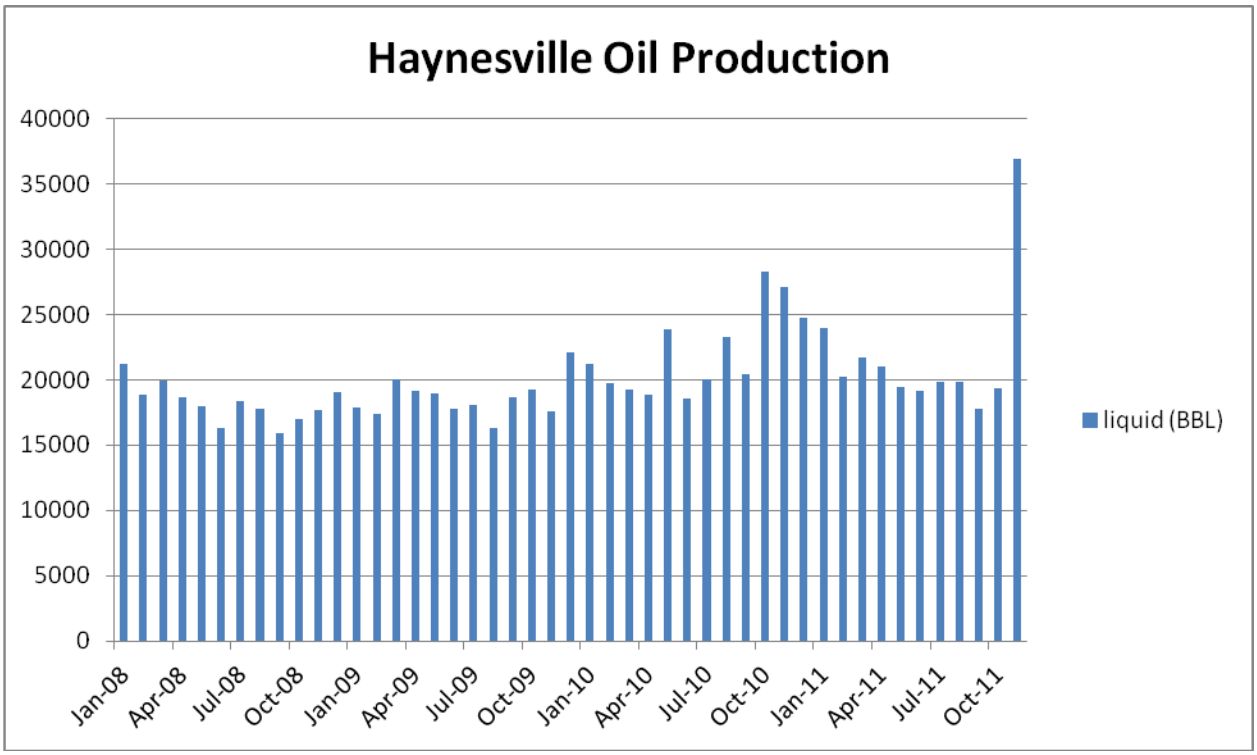

Figure 3: Cumulative liquids production for Haynesville Shale (data from IHS Enerdeq).

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MAQUOKETA AND NEW ALBANY SHALES: Illinois Basin

By Rick Sumner (Countrymark Energy Resources, LLC)

Maquoketa Shale:

There were no wells permitted for the Maquoketa Shale in the past year in Indiana, Illinois or Kentucky.

New Albany Shale

New Albany Shale activity in the Illinois Basin has been very slim in the past year. El Paso E&P, Atlas Energy Indiana and NorthStar Energy along with others continue to hold large shale acreage positions in the basin but New Albany Shale drilling activity in the basin has continued to decline from its peak in 2005-07, and most of the activity in the basin slowed to a stop in the last quarter of 2010. Of course, the major factor in the reduction of New Albany development in the past has been the current gas prices.

In Indiana, Atlas Energy Indiana permitted two New Albany wells in Knox County in 2011 that were not drilled (In. Dept. Nat. Rsc.; Scout Check). In Kentucky, Countymark Energy Resources, LLC permitted three New Albany tests: the 7-1-3T in Union County and the 8-13-01AR and the #8-13-3T in Webster County. Of those three, only the #8-13-3T has been drilled and completion results have not yet been reported (Ky. Dept. Mines & Minerals.; Scout Check). The state of Illinois has not issued any New Albany Shale permits this year (Ill. Dept. Nat. Rsc.; Scout Check).

On the bright side of all this is that there is an emerging shale play in the Basin that appears to be predominantly a liquids play and it appears that both the New Albany and Maquoketa may be targets. At least 10 companies are currently leasing large blocks of acreage in this play, with most of the activity in the extreme southern and southwestern counties in Illinois, notably Gallatin, Saline, White and Wayne counties, and also in far southwestern Indiana and adjacent counties to south of the Ohio River in Kentucky. This area is in the deeper part of the basin and is the most thermally mature.

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Commonwealth of Kentucky Department of Mines and Minerals, Division of Oil and Gas, Frankfurt, KY
The Scout Check Report, LLC, Evansville, IN

Marcellus Shale (Devonian)—Appalachian Basin, U.S.

by Catherine Enomoto (U.S. Geological Survey, Reston, VA)

The Marcellus Shale of the Appalachian Basin is the most areally extensive shale play in the U.S., covering about 66,600,000 acres (USGS Marcellus Shale Assessment Team, 2011). Extending from Tennessee to New York, the gross thickness of the Marcellus Shale increases to the northeast, with the thickest area located in northeastern Pennsylvania (Milici and Swezey, 2006; Wrightstone, 2009). The organic-rich zone of the Marcellus Shale has a net thickness of 50 to over 250 feet, and exists at drilling depths of 2,000 to 9,000 feet (Milici and Swezey, 2006; Wrightstone, 2009). The organic-rich Marcellus Shale has higher radioactivity responses, and thus higher gamma ray values on well logs, because the organic matter tends to concentrate uranium ions (Harper, 2008). Based on studies during and after the Eastern Gas Shales Project (EGSP), there is a strong relationship between higher-than-normal gamma ray response and total gas content in the black, organic-rich Marcellus Shale. In the majority of the currently productive area, the Marcellus has a vitrinite reflectance above 1.0 %Ro (Ryder and others, 2010; Milici and Swezey, 2006) and produces mostly natural gas. However, areas in southwest Pennsylvania, eastern Ohio, and northern West Virginia have reported condensate and oil production from wells in the Marcellus Shale. Published data indicates the total organic carbon content (TOC) of the Marcellus Shale is as high as 11% (Repetski and others, 2008).

As in other shale plays, horizontal drilling and induced fracturing increase permeability which allows for commercial production of hydrocarbons from this formation. The orientation of the horizontal sections of the wells and the design of the staged hydraulic fracture procedures try to enhance the natural fracture trends in the Marcellus Shale. "Slick-water fracs" have provided the best method for recovering large volumes of natural gas efficiently. These use sand as a proppant and large volumes of freshwater that have been treated with a friction reducer such as a gel. The slick-water frac maximizes the length of the induced fractures horizontally while minimizing the vertical fracture height (Harper, 2008). Issues with water supply for large volume fracturing, and disposal of produced formation water and used hydraulic fracturing water, called "flow-back" water, are being studied, and have been addressed with a variety of approaches including recycling and reuse.

In August, 2011, the U.S. Geological Survey (USGS) published Fact Sheet 2011-3092, "Assessment of undiscovered oil and gas resources of the Devonian Marcellus Shale of the Appalachian Basin Province." According to this new publication, the USGS estimated a mean undiscovered, technically recoverable natural gas resource of about 84 trillion cubic feet (TCF) and a mean undiscovered, technically recoverable natural gas liquids resource of 3.4 billion barrels in continuous-type accumulations in the Marcellus Shale. The estimate of natural gas resources ranges from 43 to 144 TCF (95 percent to 5 percent probability, respectively), and the estimate of natural gas liquids resources ranges from 1.6 to 6.2 billion barrels (95 percent to 5 percent probability, respectively). This re-assessment of the undiscovered resources in the Marcellus Shale updated the previous assessment of undiscovered oil and gas resources in the Appalachian Basin published by the USGS in 2002, which estimated a mean of about 2 TCF of natural gas and 0.01 billion barrels of natural gas liquids in the Marcellus Shale.

The increase in undiscovered, technically recoverable resources is due to new geologic information and engineering data. In late 2004, the Marcellus was recognized as a potential reservoir rock, instead of only a regional source rock. Technological improvements resulted in commercially viable gas production and rapid development of this new play in the Appalachian Basin, the oldest producing petroleum province in the United States. According to the Pennsylvania Department of Conservation and Natural Resources, the first production from the Marcellus Shale was in 2005 by Range Resources in Washington County, PA, and the first horizontal wells in the Marcellus were drilled in 2006. Natural gas production was reported from wells that were completed in the Marcellus in West Virginia as early as 2005, too.

The new estimates are for resources that are recoverable using currently available technology and industry practices, regardless of economic considerations or accessibility conditions, such as areas limited by policy and regulations. The Marcellus Shale assessment covered areas in Kentucky, Maryland, New York, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia. In Figure 1, the extent of three assessment units (AU) defined in this latest assessment are shown. Ninety-six percent of the estimated resources reside in the Interior Marcellus AU.

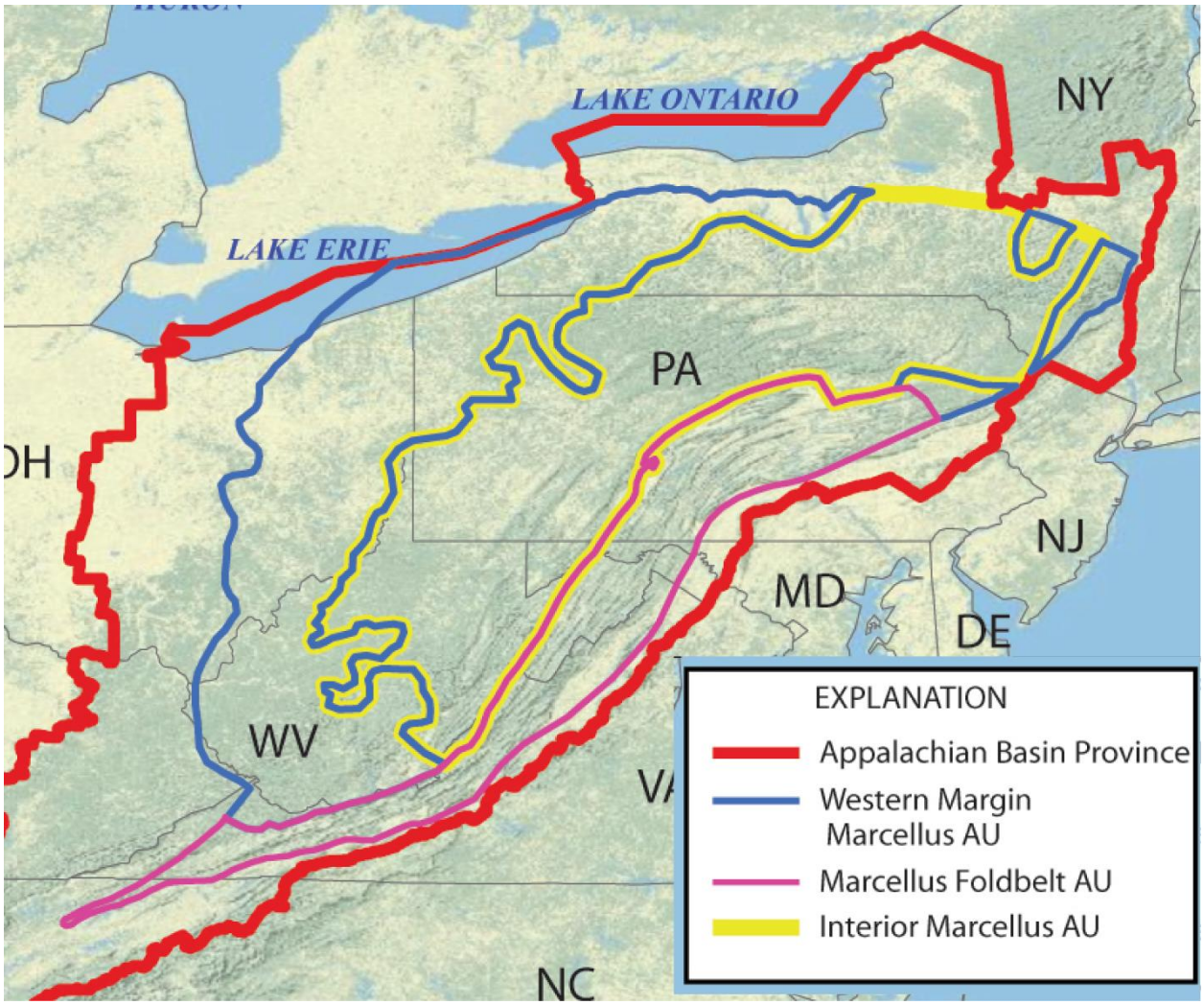

Figure 1. 2011 Marcellus Shale Assessment Units (modified from Coleman and others, 2011).

Maryland: There were no wells drilled for the Marcellus Shale between 2004 and 2011. There is no production from the Marcellus Shale in Maryland.

On June 6, 2011, the Governor of Maryland signed an Executive Order establishing the Marcellus Shale Safe Drilling Initiative. The Order requires the Maryland Department of the Environment (MDE) and Department of Natural Resources (DNR) to undertake a study of drilling for natural gas from the Marcellus Shale in western Maryland. Recommendations for best practices for all aspects of natural gas exploration and production in the Marcellus Shale in Maryland will be submitted by August 1, 2012, and a final report

with findings including environmental impacts and recommendations will be issued no later than August 1, 2014.

New York: As of October, 2011, there were 29 wells with Marcellus Shale listed as the producing formation, but only 15 reported production in 2010. Natural gas production from the Marcellus in 2010 was 34 million cubic feet (mmcf), down from 56 mmcf reported for 2009, and down from the high of 64 mmcf reported for 2008. There was no reported oil production. According to the New York Department of Environmental Conservation (DEC), there was over 203 mmcf produced from the Marcellus between 2000 and 2010. The DEC also reported that between 1967 and 1999, there may have been as much as 543 mmcf produced from the Marcellus. Production data for 2011 was not available at the time of this report.

Between 2005 and 2010, 24 wells were drilled targeting the Marcellus Shale, all of which were vertical wells. The operators included Talisman Energy USA, EOG Resources, Eastern American Energy, Chesapeake Appalachia, Petroleum Development Corp., Norse Energy Corp, U.S. Energy Development, Summit Operating LLC, Fortuna Energy, and Mesa Energy.

The NY DEC published a Preliminary Revised Draft Supplemental Generic Environmental Impact Statement (SGEIS) in July, 2011. Additional information was added and a Revised Draft SGEIS was released September 7, 2011. The public comment period ended January 11, 2012. While the process of preparing the SGEIS is ongoing, any company that applies for a drilling permit for horizontal drilling in the Marcellus Shale will be required to undertake an individual, site-specific environmental review.

Ohio: The Ohio Department of Natural Resources (ODNR) reported that almost 728 mmcf of gas, about 8,800 barrels of oil, and about 121,800 barrels of water were produced from the Marcellus Shale from 2006 through 2010. In 2010, there were 28 wells producing from the Marcellus Shale in Monroe, Noble, Washington, Belmont, Jefferson, and Carroll counties. As of March, 2012, 13 permits for horizontal wells in the Marcellus had been issued, 7 horizontal wells were drilled, and 4 were producing from the Marcellus. Production data for 2011 was not available at the time of this report.

The maximum thickness of the Marcellus Shale in Ohio is 70 feet, and averages about 50 feet in the prospective area in easternmost Ohio. However, the Marcellus is oil-productive in Ohio, making it an attractive target at current commodity prices.

A non-profit, multi-stakeholder organization reviewed Ohio's state regulatory program as to its effectiveness in regulating hydraulic fracturing. The results were published in a report titled "Ohio Hydraulic Fracturing State Review" in January, 2011. The Executive Summary states that the Ohio program is well-managed, professional, and meeting its program objectives.

In October, 2011, the ODNR Division of Oil and Gas Resources Management was created as a separate division to regulate oil and gas drilling and production operations, disposal of brine and other wastes produced from the drilling, and underground injection operations that were formerly regulated by the Division of Mineral Resources Management.

Pennsylvania: The deepest depth to the base of the Marcellus Shale is in east-central Pennsylvania, and the deepest wells to test the Marcellus have been drilled to 8,500 feet in Clinton County. The areas of greatest activity are in southwestern and northeastern PA. The production of oil and condensate from fields in southwest Pennsylvania make this area particularly attractive with current commodity prices. The counties with the most recent drilling and completion activity are Greene, Washington, Fayette, Westmoreland, Butler, Lycoming, Tioga, Bradford, and Susquehanna.

Pennsylvania has continued to be the state with the most drilling into and production from the Marcellus Shale. According to the Pennsylvania Department of Conservation and Natural Resources (DCNR) and Department of Environmental Protection (DEP), as of March 2012, over 11,700 permits to drill to the Marcellus Shale had been issued, and over 9600 of those were for horizontal wells. In January, 2012, alone, there were over 400 well permits issued for the Marcellus. By the end of 2011, there were over 6600 active horizontal wells.

By the end of 2011, 2257 wells were reported to have Marcellus production; almost half of these productive wells were horizontal wells. In 2011, there was 1067 billion cubic feet (bcf) of gas, about 683,900 barrels (bbl) of condensate, and about 383,700 bbl of oil produced from the Marcellus Shale in Pennsylvania.

Between July and December, 2011, Chesapeake Appalachia was the largest producer of natural gas with over 112 BCF in the six-month reporting period. Chesapeake was followed by Talisman Energy USA, Cabot Oil & Gas, Range Resources Appalachia, EQT Production, SWEPI LP, Seneca Resources Corporation, and Anadarko E&P Co., each with production of over 20 BCF of natural gas in the latest 6-month reporting period.

Virginia: There were no wells drilled for the Marcellus Shale between 2004 and 2011. There may be commingled gas production in vertical wells from the Marcellus Shale in southwest Virginia, but the quantity is unknown.

"The Geology of the Marcellus Shale in the Valley and Ridge Province, Virginia and West Virginia" was the title of a 2-day field trip associated with the American Association of Petroleum Geologists Eastern Section meeting in Arlington, Virginia, in September, 2011. At six stops, attendees examined the character and structural elements of the Marcellus Shale in this province, and results of geochemical and mineralogical analyses were discussed.

The George Washington National Forest (GWNF) Plan was last revised in 1993. In an effort to update its land management plan, The U.S. National Forest Service (NFS) issued the Draft Environmental Impact Statement (DEIS) and Draft Revised Land and Resource Management Plan for the GWNF in April, 2011. Several options were proposed by the NFS, but the NFS' preferred alternative forest plan included the restriction that, on lands administratively available for gas and oil leasing within the GWNF, no horizontal drilling will be allowed. The public comment period, which was initially 90 days, was extended until October 17, 2011. After reviewing the comments and completing an update of the analyses, the NFS expects to complete the Final EIS and Final Land and Resource Management Plan for the GWNF by July, 2012.

West Virginia: As of February, 2012, about 1570 wells were completed in the Marcellus Shale, according to the West Virginia Department of Environmental Protection (DEP), and West Virginia Geological and Economic Survey. Production of approximately 4.6 BCF in 2006, 10.1 BCF in 2007, 19.2 BCF in 2008, 32.5 BCF in 2009, and 57.5 BCF in 2010 can be attributed to wells with Marcellus Shale reported as at least one of the pay zones. Total production from wells completed in the Marcellus from 2005 to 2010 was almost 125 BCF of gas, and over 307,000 barrels of oil. West Virginia is second to Pennsylvania in production of hydrocarbon liquids from the Marcellus Shale.

Based on volume of gas production in 2010, the major producers included Chesapeake Appalachia, Antero Resources Appalachian, Cabot Oil & Gas, Equitable Production Company, AB Resources PA, Hall Drilling LLC, Eastern American Energy Corp., Jay-Bee Oil & Gas, and Hard Rock Exploration. Production data for 2011 was not available at the time of this report.

Production from a "deviated," or horizontal, well in West Virginia was first reported in 2007. Although the well records of 2010 indicate that 177 wells completed in the Marcellus are deviated, over 400 wells list the Marcellus Shale as the only pay zone, and may represent the maximum number of horizontal wells completed in the Marcellus. Most of the completed Marcellus wells that are reported as "deviated" are located in Marshall, Wetzel, Monongalia, Marion, Preston, Taylor, Harrison, Doddridge, Lewis, and Upshur counties.

Visit the following web sites for more information on the Marcellus Shale:

http://www.eia.gov/oil_gas/rpd/shale_gas.pdf

http://www.eia.gov/energy_in_brief/about_shale_gas.cfm

http://geology.com/articles/marcellus-shale.shtml

http://www.wvgs.wvnet.edu/www/datastat/devshales.htm

http://www.dep.wv.gov/oil-and-gas/databaseinfo/Pages/default.aspx

http://www.mgs.md.gov/geo/marcellus.html

http://www.mgs.md.gov/geo/pub/MarcellusShaleGeology.pdf

http://www.mde.state.md.us/programs/Land/mining/marcellus/Pages/index.aspx

http://www.dec.ny.gov/energy/46288.html

http://www.dec.ny.gov/energy/36159.html

http://www.dec.ny.gov/energy/205.html

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http://www.ohiodnr.com/mineral/oil/tabid/10371/Default.aspx

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http://www.dnr.state.oh.us/Portals/11/oil/pdf/stronger_review11.pdf

http://www.dcnr.state.pa.us/topogeo/pub/pageolmag/pdfs/v38n1.pdf

http://www.dcnr.state.pa.us/topogeo/econresource/oilandgas/marcellus/index.htm

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Monterey Formation (Miocene), various California basins, U.S.

by Margaret A. Keller (U.S. Geological Survey)

The Monterey Formation of central and southern California, USA, is widely known as a world-class petroleum source rock (one of the geologically youngest) and for sourcing much of the petroleum in California over the 100 plus years of development (e.g., see Behl, 1999; Isaacs, 2001; Isaacs and Rullkötter, 2001). Most of this production occurs in California's share of the EIA's top 100 oil and gas fields of the USA (http://www.eia.doe.gov/oil_gas/rpd/topfields.pdf), and is predominantly heavy oil in the coastal regions (e.g., Santa Maria and Santa Barbara-Ventura), and lighter oil in the interior basins (e.g., San Joaquin; see USGS Professional Paper 1713 at http://pubs.usgs.gov/pp/pp1713/). Conventional gas production occurs in both the onshore (http://www.eia.doe.gov/oil_gas/rpd/conventional_gas.pdf) and offshore regions (http://www.eia.doe.gov/oil_gas/rpd/offshore_gas.pdf) of California. However, California and the Monterey Formation are not highlighted on the most recent EIA map of shale gas plays for the lower 48 states (http://www.eia.doe.gov/oil_gas/rpd/shale_gas.pdf), and so far, no shale gas production has been reported. The Monterey Formation is primarily an oil play because much of the formation is either currently within the oil window or has not matured beyond that. Only a few places have the high maturity required to match the Barnett model [for shale gas] -- southern San Joaquin, western Ventura, and Los Angeles (P. Lillis, Pers. Comm. 8/12/10). Nevertheless, some characteristics of the gas production from siliceous shales of the Monterey Formation at Elk Hills (http://www.onepetro.org/mslib/servlet/onepetropreview?id=00035742&soc=SPE) fit some of the criteria for a shale gas play.

The Monterey Formation is notable for and primarily recognized by its fine-grained lithofacies that contain abundant biogenic silica from diatoms. These lithofacies - diatomite and diatomaceous shales or mudstones - and their diagenetic equivalents - chert, porcelanite, and siliceous shales or mudstones - and characteristic interbedding at millimeter scale, distinguish the Monterey Formation from other Tertiary rock systems in California which, for the most part, comprise predominantly terrigenous derived siliciclastic rocks - clay-rich and clay-dominated mudstones, sandstones, and coarser-grained lithofacies. In addition to being the source for most of the petroleum in reservoirs of interbedded coeval sandstones and adjacent Tertiary strata, within the past 3 decades the Monterey Formation has become better known for self sourcing its less conventional, fine-grained reservoir lithofacies (oil and associated gas in fractured chert, diatomite, and siliceous shale reservoirs within the formation). Two different oil types (low and high sulfur Monterey

sourced systems) originate from different type II kerogens - generally those forming within the more proximal parts of the Monterey depositional system being low in sulfur and those in more distal areas of the system being relatively higher in sulfur (Orr, 1986).

Resurgence in exploration for shale oil in the Monterey Formation is occurring again in California (Durham, 2010; Huggins, 2010). Durham's (2010) article quotes Marc Kammerling's estimate of ultimate recovery from fields identified as Monterey producers only as 2.5 billion barrels. Durham (2010) also reports that the Monterey is "estimated to contain more than 500 billion barrels of oil in place." As noted by Huggins (2010), "thousands of acres have been leased and top leased, millions of dollars have been invested in shooting seismic and drilling wells. New rigs are arriving on a regular basis, and land consultants are being brought in from out of state to deal with all the transactions and lease checks." In addition to providing a short history of the evolution of Monterey development/exploration concepts, Huggins (2010) also makes the important point that "the other big change is the realization that significant thicknesses of high total organic carbon-rich rocks, in the right structural configuration, with the right combination of porosity and permeability, can in themselves be productive."

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Neal/Floyd Shale (Mississippian), Black Warrior Basin, U.S.

by Kent A. Bowker (Bowker Petroleum, LLC)

Currently, there is no drilling activity in either the Neal Shale or Conasauga Shale plays in the basin. Most of the acreage positions that were put together 6-7 years ago in the Neal Shale play nearly completely expired. Poor results and low natural-gas prices have caused all Devonian- and Cambrian-shale activity in the Ouachita trend of central Alabama to be at least temporally abandoned.

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On July 30, 2011, Jack Pashin and his colleagues at the Geological Survey of Alabama published an exhaustive review of the gas potential from various shale horizons in Alabama (http://www.gsa.state.al.us/gsa/07122-17%20Final%20Report.pdf). This report includes detailed petrographic work on several shales in the Black Warrior and Appalachian basins along with estimates of

gas in place, discussions of organic geochemistry, and reviews of drilling results to date. At 175 pages, it is the most complete review of the petroleum geology of the Alabama shales available.

Niobrara Formation (Cretaceous), Rocky Mountain Region, U.S.

by Stephen Sonnenberg (Colorado School of Mines)

The Niobrara is a significant, self-sourced, resource play throughout the Rocky Mountain region. New technology of horizontal drilling and multi-stage, hydraulic-fracture stimulation is unlocking reserves that previously were not obtainable.

Known production comes from both fracture and matrix porosity systems (dual porosity). High matrix porosity is present in the shallow biogenic gas accumulations of eastern Colorado and Western Kansas. The shallow biogenic play is important for natural gas production at burial depths of less than 3500 feet. The deeper Niobrara thermogenic accumulations generally occur at burial depths greater than 7000 feet. Burial diagenesis (chemical and mechanical compaction and cementation) reduces porosities to values less than 10 percent in the deeper parts of the various basins where the Niobrara is prospective. Mature Niobrara source rocks are located in these areas of low porosity. Natural fractures are important contributors to production in the deeper areas.

The Niobrara Petroleum System contains all the aspects of a large resource play (e.g., widespread mature source and reservoir rocks, self-sourced). The Niobrara was deposited in the Western Interior Cretaceous (WIC) Basin and is a widespread unit in the Rocky Mountain Region (Fig. 1). The WIC Basin was broken into numerous smaller basins during the Laramide orogeny. The Niobrara contains reservoir rocks, rich source beds and abundant seals. The various productive lithologies all have low porosity and permeability. TOC values in shales locally range from 2% to 8% in the eastern WIC area and are reduced to 1-3% because of siliciclastic dilution in the western WIC area. Laramide structural events exert the primary control on fracturing within the Niobrara as well as thermal maturity. Neogene extension fracturing is also thought to be an important component for locating production "sweet spots." Understanding the thermal maturity of the source rocks will assist in predicting the distribution of hydrocarbon accumulations. Hydrocarbon generation may enhance the tectonic fractures and may also create new ones as a result of overpressuring associated with this process.

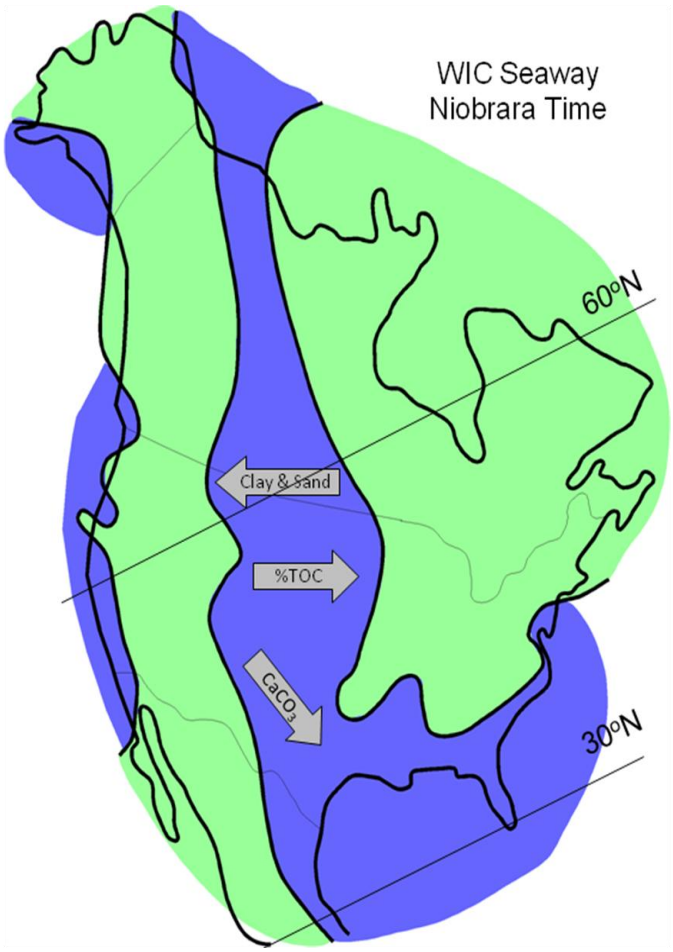

Figure 1. The Western Interior Cretaceous Basin during Niobrara time (modified from Longman et al., 1990). Source area for clastics is dominantly to the west, total organic carbon content in the Niobrara increases to the east, carbonate content generally increases on the eastern side of the Western Interior Cretaceous (WIC) seaway and to the southeast.

A summary of factors thought to be important for Niobrara production in the Rocky Mountain region are as follows: presence of favorable reservoir facies (brittle chalk) and a diagenetic history that enables open fracture systems to exist; presence of mature source rocks to enable a continuous oil column to exist in the trap; source rocks interbedded with respect to the reservoir limestone (chalk); a favorable tectonic history for fracture formation. Most fracture systems fall into two major categories: structure-related fractures and regional orthogonal fractures.

Resistivity mapping can be used to determine both the presence of a hydrocarbon accumulation and the maturity of source rocks for the Niobrara. The presence of oil in open fracture systems is thought to be the cause of the high resistivity anomalies in chalk beds. A relationship between increasing resistivity of source shales with increasing thermal maturity has also been demonstrated.

Knowledge of the distribution and occurrence of hydrocarbon source and reservoir rocks in the Niobrara interval will greatly aid future exploration.

REGIONAL SETTING

The Upper Cretaceous Niobrara (Coniacian-Campanian; ~ 82 to 89.5 million years ago) was deposited in a foreland basin setting in the Western Interior Cretaceous Seaway of North America during a time of a major marine transgression (Fig. 1). This major transgression probably represents the maximum sea-level highstand during the Cretaceous and may contain the best source rocks in the Cretaceous. The present-day basins in the Rocky Mountain region formed during the Late Cretaceous to Early Tertiary Laramide orogeny.

The Western Interior Cretaceous (WIC) Basin was an asymmetric foreland basin with the thickest strata being deposited along the western margin of the basin (Figs. 1, 2). The WIC Basin is a complex foreland basin that developed between mid to late Jurassic to Late Cretaceous time. The basin was bordered by mountainous areas to the west (zone of plutonism, volcanism, and thrusting that formed the Cordilleran thrust belt) and a broad stable cratonic zone to the east. The foreland basin subsided in response to thrust and synorogenic sediment loading and pulses of rapid subduction and shallow mantle flow.

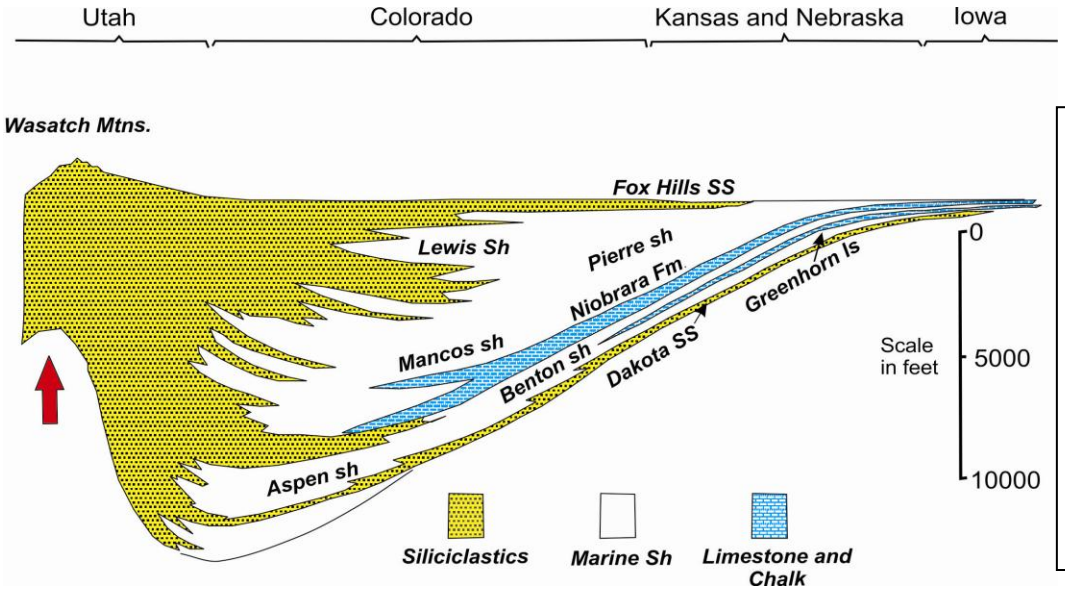

Figure 2. Generalized cross section across the Western Interior Cretaceous Basin. The Niobrara is Upper Cretaceous in age. Limestone and chalk beds are present over the eastern two thirds of the basin (modified from Kauffman, 1977).

During sea-level highstands, coccolith-rich and planktonic foraminifera-rich carbonate sediments (chalks) accumulated on the eastern half of the seaway. Chalky beds extend into Montana and southern Canada (where they are called the White Spec zones) and into the Gulf Coast region (Austin Chalk). Chalk-rich carbonate facies change westward into siliciclastic-rich beds.

STRATIGRAPHY AND DEPOSITIONAL SETTING

The Niobrara represents one of the two most widespread marine invasions and the last great carbonate producing episode of the Western Interior Cretaceous basin (the first widespread event is represented by the Greenhorn chalks). The dominant lithologies of the Niobrara Formation are limestones (chalks) and interbedded with marls and calcareous shales (Figs. 2, 3). The chalk-shale cycles are interpreted to represent changes from normal to brackish water salinities possibly related to regional paleo-climatic factors or sea level fluctuations. The chalk lithologies are thought to represent deposition in normal to near normal marine salinities having a well-mixed water column and well oxygenated bottom waters. The chalks reflect influx of warm Gulfian currents into the WIC seaway during relatively high sea levels. The interbedded shale/marl cycles are interpreted to be caused by an increase in fresh water runoff caused by increased rainfall which may be related to climatic warming. The fresh water runoff creates a brackish water cap and salinity stratification. Vertical mixing of the water column is inhibited causing anoxic conditions in the bottom waters. This enhances preservation of organic material and results in organic-rich source rocks. The decrease in water salinities is also suggested by oxygen isotopic values. The shalier intervals may reflect lower sea levels and greater influx of clastic material from the west. The chalks have previously been interpreted to represent higher sea levels during Niobrara time.

Three major facies are present in the Niobrara and equivalents across the Rocky Mountain region (Figs. 1 and 2). On the western side of the area, a sandstone facies is present which changes laterally to the east into a calcareous shale facies, and which, in turn, changes eastward into a limestone and chalk facies. These various lithologies interfinger and the facies changes are very gradational. The Niobrara name is used for chalk and shale units located on the eastern side of the Western Interior Seaway; whereas, the term Mancos is generally used for the equivalent shale, and siltstone units in the western part of the area. The equivalent shoreline and non-marine sandstone units further to the west are known by a variety of names. The limestone facies is composed of coccolith-rich fecal pellets probably derived from pelagic copepods, inoceramid and oyster shell fragments, planktonic foraminifer tests, micrite, clay, and quartz silt. The thick siltstone facies was derived from highlands to the west. The shales found in the Mancos/Niobrara are dark-gray to black and generally organic rich (>1% TOC). The shales are fair to excellent source rocks and also provide seals for the chalky and sandy reservoir facies. TOC content in the interval increases to the east (Fig. 1).

The chalks of the Niobrara are rich in organic matter and organic related material (e.g., pyrite). On the east side of the WIC basin, the Niobrara consists of four chalk beds and three shale intervals (Fig. 3). The basal chalk bed is known as the Fort Hays limestone member and the unit contains some of the purest chalk in the Western Interior. The Fort Hays is regionally extensive and ranges in thickness from 50 feet in southeast Colorado to 120 feet in New Mexico to less than 10 feet in southeast Wyoming. Carbonate content persists from the Denver Basin to southwest Colorado into the Laramie, North Park, South Park, and Sand Wash basins. The Fort Hays interval is difficult to distinguish from the remainder of the Niobrara north of the Laramie Basin.

The Fort Hays is overlain by the Smoky Hill member. The Smoky Hill consists of organic rich shales to chalky shale (marls) to massive chalk beds. The interval has been subdivided by various authors into several units. Figure 3 illustrates a six member subdivision.

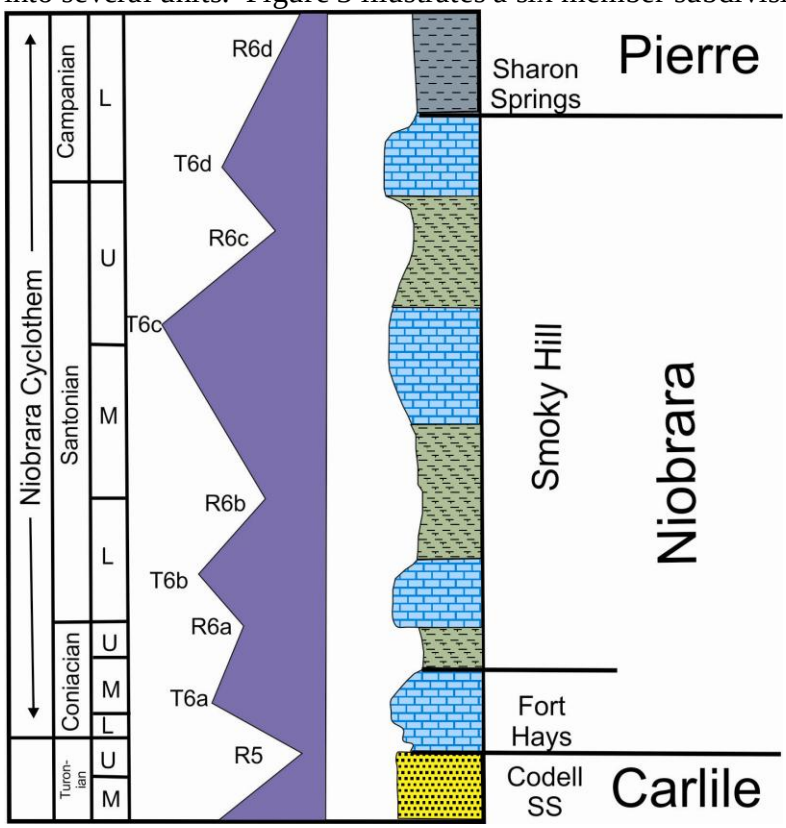

Figure 3. Generalized stratigraphic column for the Niobrara from the Denver Basin setting. The Niobrara ranges in age from Coniacian to lower Campanian. Several transgressive and regressive cycles are noted for the Niobrara interval. Four chalk –rich intervals were deposited during trangressive events , calcareous shales during regressive events (modified from Longman et al., 1998; Barlow and Kauffman, 1985).

The Niobrara ranges in thickness from 100 to 300 feet along the eastern side of the WIC basin to over 1500 feet on the west side of the WIC basin. Figure 4 illustrates an isopach map of the Niobrara across the northern Rockies region. Thinning occurs is a northeast trend across the map area. This thin trend was related to paleotectonic movement on the Transcontinental arch. Superimposed on the Transcontinental arch are northeast axes of thinning (Fig. 4). Thinning in the Niobrara is believed to result from differing rates of sedimentation (i.e., convergence or divergence of section) and unconformities at the base, within, and at the top of the formation.

Niobrara deposition in the Western Interior Basin was strongly influenced by the interplay of warm north-flowing currents from the paleo-Gulf of Mexico and cooler southward-flowing currents from the Arctic region along with sea level fluctuations. Warm waters from the Gulf brought in rich carbonate flora of coccoliths and promoted carbonate production and deposition. Siliciclastic input from the west and cooler Arctic currents inhibited carbonate production and deposition.

Chalks and marls are abundant in the Denver Basin. The section changes to marl and is shalier west of the Front Range and north of the Hartville Uplift. Chalk intervals extend into the Laramie, Hanna, North Park, Sand Wash, and Piceance basins. The section in the Piceance consists of interbedded sandstone, siltstone, and shale. In the San Juan Basin, the Niobrara consists of a mixture of siliciclastic and marl lithologies.

The Niobrara is overlain by the Pierre Shale in the eastern part of the Western Interior Basin and its age equivalent Mancos shale in the western part. The Niobrara overlies the Carlile Formation across much of the Western Interior basin (and its members: Codell Sandstone, Sage Breaks Shale, etc.). The Sharon Springs member of the Pierre shale overlies the Niobrara in most of eastern Colorado. The Sharon Springs is an excellent source rock with TOC's ranging from 2 to 8 weight percent.

The type locality for the Niobrara Chalk is Knox County in northeastern Nebraska.

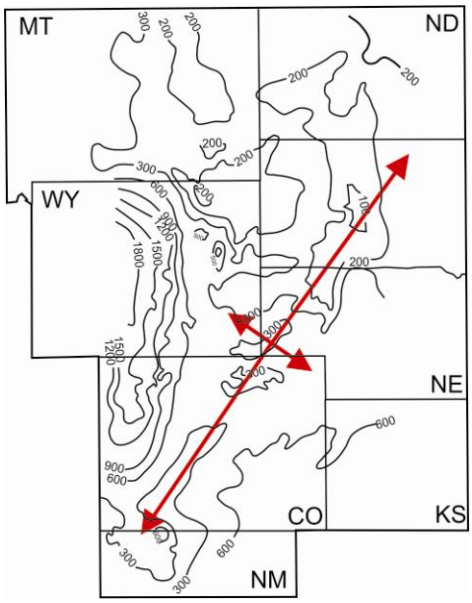

Figure 4. Isopach of the Niobrara across the northern Rockies (modified from Longman et al., 1998). The Niobrara ranges in thickness from less than 100 feet to over 1800 feet. Thinning occurs in a northeast trend across the area known as the Transcontinental Arch (Weimer, 1978).

SOURCE ROCKS

Several workers have discussed the organic-rich nature of the Niobrara Formation and the increased thermal maturity and resistivity with increased burial depth. Vitrinite reflectance and resistivity of the organic-rich shale both increase with increasing thermal maturity. These values can be mapped to show areas of source rock maturity.

The Niobrara Formation has been analyzed using the Rock-Eval instrument by several workers (Fig. 5). Organic-rich beds in the formation have total organic carbon values which average 3.2%. A plot of hydrogen index versus oxygen index (modified van Krevelen diagram) illustrates the type and level of maturity of the source rocks for different depths across the Denver basin. The plot also illustrates that the kerogen present in the Niobrara is Type-II or oil-prone (sapropelic).

RESERVOIR ROCKS

The lithology of the Niobrara changes from east to west across the Western Interior Basin (Fig. 2). In the Denver Basin, the lithology consists of interbedded calcareous shale, shaley limestones, marls, and limestones (Fig. 3). Westward, the lithology becomes shalier and sandier (Fig. 1). The carbonates are still present in the western area but clastics begin to dominate.

Most of the Niobrara reservoir rocks have undergone mechanical and chemical compaction and are low porosity and permeability rocks. Burial depth is the single most important factor affecting porosity in the Niobrara. Chalks have high original porosities (50% or greater). Initial dewatering and mechanical compaction is the first diagenetic phase. Grain and fossil breakage and re-orientation reduce porosity. Initial coccolith grain sizes are 0.2 to one micron. Chemical compaction is characterized by calcite dissolution along wispy dissolution seams, microstylolites, and stylolites. Grain-to-grain dissolution along microstylolites is common and the dissolved calcite is reprecipitated locally.

HYDROCARBON PRODUCTION

Niobrara production represents some of the oldest established production in the Rocky Mountain region. The oldest field in the region is the Florence-Cañon City field which was discovered in 1881 (Fig. 6). The field produces from the Pierre shale immediately above the Niobrara and is believed to be sourced from the Niobrara and Sharon Springs. The Boulder oil field (western Denver basin) was discovered in 1901 and is also productive from fractured Pierre shale but also sourced from the Niobrara. Fractured Mancos shale production was found in Rangely (northwest Colorado) in 1902. Niobrara production was established in Tow Creek (Sand Wash basin) in 1924. The Berthoud field of the western Denver basin is productive from several horizons including the Niobrara and discovered in 1927. Gas in the Niobrara was discovered in Beecher Island (eastern Colorado) in 1919 (commerciality was not established until 1972, however). The Niobrara interval is productive in the Bowdoin field of Montana which was discovered in 1913. The reason for these early discoveries is that many of them are associated with surface structures which were the primary targets of early explorers.

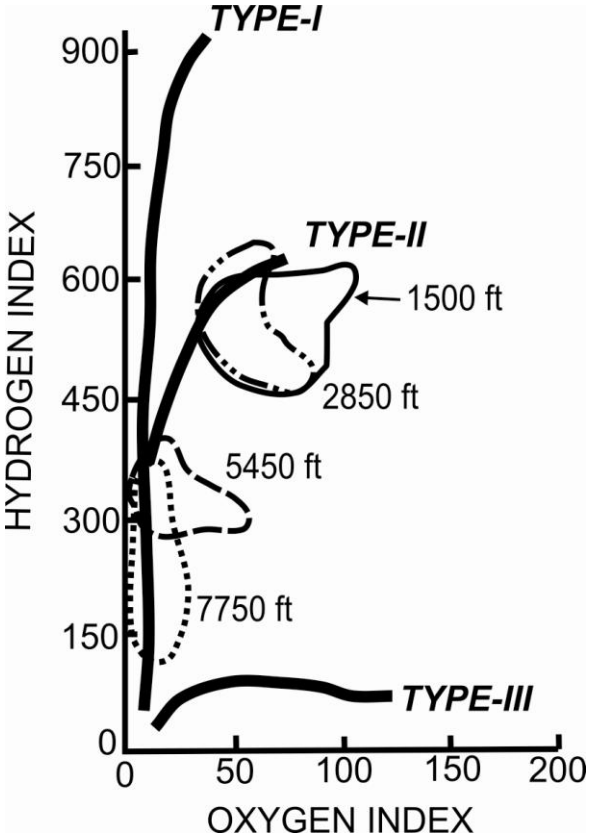

Figure 5. Niobrara Van Krevelen diagram. Niobrara source rocks are Type-II (oil prone) kerogens based on Rock Eval data. With increasing burial depth and thermal maturity the HI values decrease significantly. Data from Rice (1984); Barlow (1985); Pollastro (1985); after Sonnenberg and Weimer (1993).

Hydrocarbon production comes from all three major Niobrara lithofacies: 1) microporous and fractured coccolith- and planktonic foraminifer-rich limestone (eastern part of WIC basin); 2) fractured marls and shales (mainly in the central part of the seaway); 3) fractured sandstone and siltstone rich facies, mainly in the western and southwestern parts of the seaway. Production occurs in the Laramide-aged Powder River, Denver, North Park, Greater Green River (including Sand Wash), Raton, San Juan, and Piceance basins and in north-central Montana. The widespread distribution of the production along with many wells with hydrocarbon shows across these basins suggests a large resource play may exist. The majority of recent drilling activity in the Niobrara has been in the Denver Basin, north of Wattenberg field and in southeast Wyoming around the Silo field.

Hydrocarbon production from chalk reservoirs occurs along the shallow eastern margin of the Denver basin. Many of the gas accumulations in this area occur in structural traps and reservoirs require hydraulic-fracture stimulation. The gas is biogenic or microbial in origin. Production in the shallow play comes from the upper chalk bench or Beecher Island member of the Niobrara and is mainly from microporosity within the chalks, but is enhanced by natural fracturing. Production from the shallow

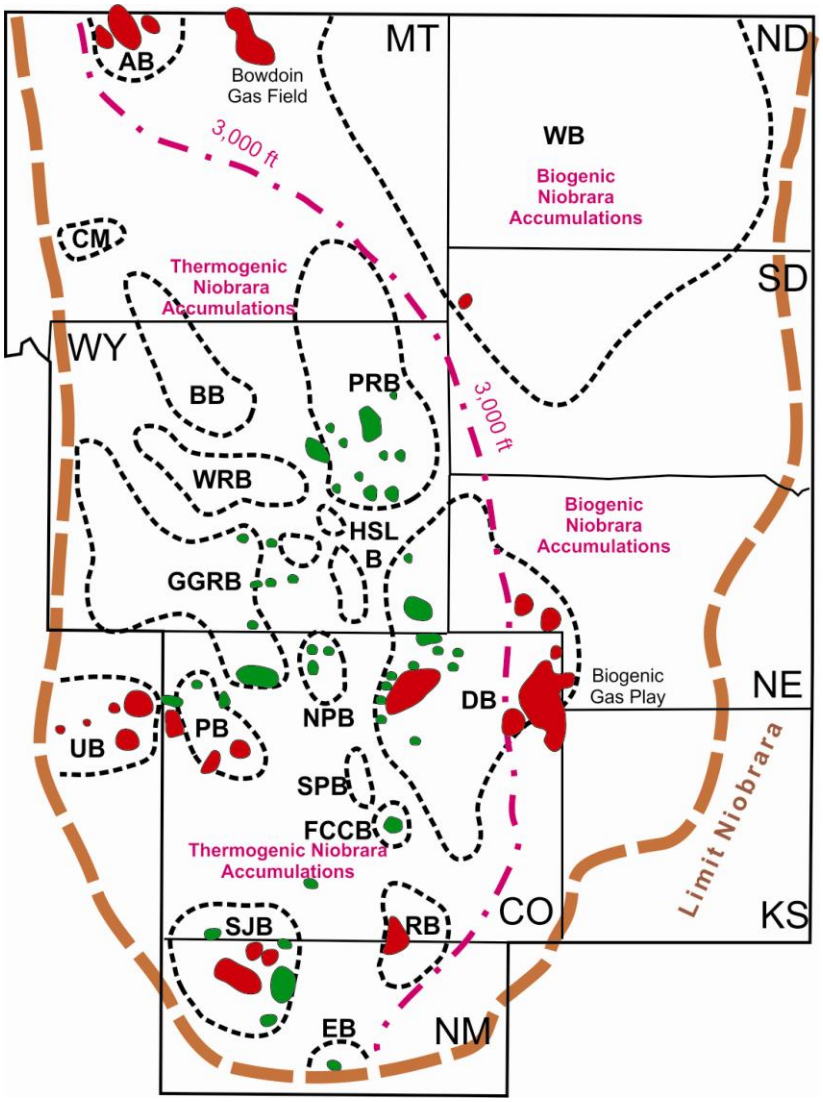

Figure 6. Niobrara producing areas across the north Rockies (Oil fields-green; gas fields-red)(modified from Longman et al., 1998). Basin abbreviations are as follows: AB-Alberta Basin; CM-Crazy Mountain; WB-Williston Basin; BB-Bighorn Basin; PRB-Powder River Basin; WRB-Wind River Basin; GGRB-Greater Green River Basin; NPB-North Park Basin; PB-Piceance Basin; UB- Uinta Basin; SPB-South Park Basin; FCCB-Florence-Canon City Basin; SJB-San Juan Basin; RB-Raton Basin; DB-Denver Basin; EB-Estancia Basin. Distribution of sapropelic oil-generation-prone Niobrara source rocks within brown dashed line (Meissner et al., 1984). Dot-dashed line equals 3,000 ft current burial depth; biogenic accumulations east of line; thermogenic accumulations west of line (from Lockridge and Scholle, 1978).

Niobrara from eastern Colorado is 600 BCFG. Beecher Island Field is one of the largest and first fields discovered in the shallow Niobrara. Commercial production dates back to 1972 (initial discovery in 1919!) and the cumulative for the field is 100 BCFG. Three-dimensional seismic data have been used effectively to improve development and exploration success ratios in fields.

Shallow gas production from the Niobrara also occurs in north central Montana. Bowdoin Dome has produced 62 BCFG and 19 MBO from the Niobrara. Additional Niobrara fields are located to the west the Alberta Basin extends into Montana. The largest field to date is the St. Joe Road field which was discovered in 2001 and has produced 18.2 BCFG.

Deeper in the Denver Basin, the Niobrara is oil productive in a number of fields. The porosity of the chalks in the deeper part of the basin has been dramatically reduced by compaction and burial diagenesis. Production is attributed to the presence of fractures in the chalky intervals. Some attempts have been made to establish production from some of the rich, shaley intervals within the Niobrara. The shale gas and fractured chalk potential of the deep Denver basin area is significant as shown by fields like Wattenberg and Silo. Silo Field was discovered in 1981 and has produced approximately 10.4 MMBO and 8.9 BCFG.

The Niobrara is productive on the Casper Arch of Wyoming at Salt Creek and Teapot fields. Total production has been 1.5 MMBO and 0.2 BCFG. In the deeper Powder River Basin production has been

established in a number of accumulations including Fetter, Hilight, Brooks Draw and Flat Top. Hilight has produced 411 MBO and 0.8 BCFG to date.

The western portion of the region is productive in a variety of traps and lithologies (mainly siliciclastic) and there is significant potential for hydrocarbon production in many of the western basins. The basal part of the Niobrara equivalent in the west yields oil and gas in the San Juan basin from a sandstone and shale interval (Tocito and Gallup sandstones). Examples of producing fields from the Gallup are Bisti and Verde fields. Bisti Field has produced 41.8 MMBO and 79.2 BCFG. Verde Field has produced 8.1 MMBO and 2.5 BCFG. Examples of fields producing from the Tocito Sandstone are the Blanco South and Chipeta fields. These fields have produced 4.2 MMBO and 18.8 BCFG. Production is from interparticle porosity but is enhanced by fractures. The upper Niobrara equivalent (Smoky Hill member) is productive in the Sand Wash basin from fractured reservoirs (Fig. 6) and perforated intervals are commonly long. Field examples are Buck Peak and Tow Creek. Buck Peak has produced 4.8 MMBO and 8.5 BCFG. Tow Creek has produced 3 MMBO and 0.3 BCFG. Farther to the west where the Niobrara equivalents are dominantly shale, production is found in the Rangely and Douglas Creek Arch fields. Production form fractured Mancos shale at Rangely represents some of the oldest production in Colorado (1902). The Mancos at Rangely has produced around 11.9 MMBO and 0.2 BCFG. Neogene age extensional faulting is a key to production at Buck Peak and Rangely. The extensional fracture trend is N60W. The Douglas Creek arch production comes mainly from Cathedral Field. The field has produced 56.5 BCFG and 40.6 MBO from the Mancos (mainly the Mancos B zone).

Other production equivalent to the upper Niobrara zone comes from the Mancos interval in the San Juan basin. Examples of Mancos producing fields are: East and West Puerto Chiquito, Rio Puerco; Gavilan, Basin, and Boulder. These fields are interpreted to be fractured reservoirs and producing intervals are hundreds of feet thick. The Puerto Chiquito fields have produced 19.3 MMBO and 55.5 BCFG. Gavilan Field has produced 7.8 MMBO and 111 BCFG. Boulder Field has produced 1.8 MMBO and 1.6 BCFG. Basin Field has produced 120 MBO and 4.1 BCFG. Rio Puerco Field has produced 1.3 MMBO and 1.4 TCFG.

The Mancos is gas productive in the deeper parts of the Uinta basin in several fields including Natural Buttes. Mancos is also productive in some silty and very fine-grained sandstone zones in the Cathedral field of the Douglas Creek Arch. New Mancos/Niobrara production has been established in several areas of the deeper Piceance Basin (e.g., Mamm Creek field).

EXPLORATION METHODS

Methods of exploration for fractured Niobrara reservoirs should incorporate many if not all of the following: seismic acquisition; aeromagnetics study; surface lineament analysis; subsurface mapping; isoresistivity mapping; logging technology; and technology to produce the reservoir. 2-D and 3-D seismic is extremely important to map structural anomalies. Three-dimensional three-component (compressional and shear wave data) methods have also proved to be effective in analyzing the fractured reservoir. Aeromagnetics is a tool that may identify basement shear zones areas of potential fractures having gradient changes such as narrow zones of steep gradients. Aeromagnetic data examined in the Silo field area illustrates possible northwest-trending shear zones. If basement fracture systems propagate all the way to the surface then a surface lineament analysis may also be effective. Northwest-trending surface lineament in the Silo area have been mapped by use of remote sensing techniques. Resistivity mapping is important to show areas of oil accumulation. When resistivity mapping is combined with subsurface mapping the most probable areas of fracturing can be predicted. Logging technologies available to identify fractured reservoirs are geophysical logs such as the FMS, FMI and CAST logs. Horizontal drilling and multi-stage hydraulic fracturing offer technologies to economically produce hydrocarbons from the reservoir.

An understanding of the regional stress field is important in most tight oil and gas plays. The direction of maximum horizontal stress (Shmax) is generally the direction of open fractures. Regional horizontal stress maps have been published for North America. The present-day stress field reflects Neogene extensional tectonics and the epeirogenic uplift that has taken place in the western United States.

Regional epeirogenic uplift of western North America and subsequent erosion (denudation) may play a role in Niobrara microfractures. The removal of overburden results in lowered effective stress in rocks that may also be overpressured. This mechanism may be important in all tight-reservoir plays in the Rocky Mountain Region.

SUMMARY

Widespread source and reservoir rocks make the Niobrara Formation an attractive target for exploration across the Rocky Mountain region. The Niobrara contains mature source rocks interbedded with brittle limestones (chalks) in the deeper parts of many basins in the Rocky Mountain region. Thermogenic production occurs from the chalk intervals in the eastern part of the region and from siliciclastics and shales in the western and southwestern parts of the Rocky Mountain regions (Uinta and San Juan basins). Biogenic gas production occurs at shallow depths along the eastern Rocky Mountain region in Colorado, Kansas, and Nebraska. Generally production comes from depths less than 3500 feet. Shallow gas production also occurs in several areas of north-central Montana. The shallow gas production generally is structurally controlled.

The Niobrara reservoirs generally have low permeabilites so natural fracturing plays a role in economic production. The limestone (chalk) beds behave in a brittle manner, whereas, the adjacent calcareous shales often behave in a ductile manner. Fractures occur for a variety of reasons and several models can be used for exploration. Early created fractures are susceptible to extreme diagenesis and thus generally completely cemented. Late stage structural movement can help re-open old fractures or create new ones.

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UTAH SHALES, U.S.

By Robert Ressetar (Utah Geological Survey) and Lauren P. Birgenheier (Dept. of Geology and Geophysics, University of Utah).

Overview: The Upper Cretaceous Mancos Shale is an emerging shale-gas play in the Uinta Basin of eastern Utah. The Mancos averages 4000 feet thick across the Uinta Basin, in contrast to the gas shales currently in production in other U.S. basins, whose thicknesses range from 50 to 600 feet (U.S. Department of Energy, National Energy Technology Laboratory [U.S. DOE], 2009). The thickness of the Mancos presents a challenge to operators in the Uinta Basin, who must evaluate large amounts of data to identify pay zones (Halliburton Company Web document, undated).

The Mancos consists mostly of offshore marine mudstone that was deposited on the western margin of the Western Interior Seaway. The Mancos displays an overall progradational stacking pattern from west to east, but in detail it exhibits significant variations in sedimentary composition and texture. Understanding the distribution of the subunits within the Mancos and the resultant variations in reservoir properties poses a major challenge to shale-gas exploration.

Four members of the Mancos have shale-gas reservoir potential: the Prairie Canyon Member (Mancos B), the Lower Blue Gate Shale Member, the Juana Lopez Member, and the Tropic-Tununk Shale (Schamel, 2006). The potential shale-gas members are up to 1500 ft thick, have 2% to 5% porosity, and contain some overpressured zones.

Most of the Mancos is organically lean, but it contains richer condensed sections and gas shows are common throughout. Anderson and Harris (2006) reported a TOC range of 0.44% to 4.32%, and an average of 1.23% for the lower Mancos in the southeastern Uinta Basin. Vitrinite reflectance ranges from 0.60% to 1.76% at the top of the Mancos, and from 0.70% to 3.6% at the base (Nuccio and Roberts, 2003).

Mancos gas in place and recoverable reserves are poorly understood, and the exact extent of the play has not been defined, due to the limited amount of exploration and production. Estimated in-place gas is reportedly between 280 and 350 BCF/mi^2, with a projected estimated ultimate recovery of 5% to 15% of in-place gas. Initial flow rates range from 1000 to 2000 MCFPD. For wells in the northeastern Uinta Basin, QEP Resources estimate 3 to 6 BCFG recoverable, and initial potentials of 5 MMCFGPD have been reported. Not surprisingly, recovery will vary widely throughout different areas of the basin.

Activity: Two factors indicate that the Mancos Shale is a promising, emerging shale gas play in the Uinta Basin. First, historical production from sandstone-dominated and heterolithic reservoirs has been economical. Second, production from other mud-dominated Mancos intervals is now proven within portions of the Uinta Basin.

The Utah Division of Oil, Gas, and Mining has identified 36 fields with producing or potential natural gas reservoirs in the Mancos Shale. In spite of this, the emerging Mancos Shale gas play only has a few completions, probably less than 100, scattered over the basin, and mostly drilled post-2005. Most Mancos completions are commingled with gas production from overlying and underlying sandstone

reservoirs. The majority of Mancos gas production to date has come from conventionally completed vertical wells in the sandier facies like the Prairie Canyon and Juana Lopez Members.

The first horizontal well in the Mancos—XTO Energy's HCU 1-30F—was completed in late 2010 in the Natural Buttes field. Cumulative gas production through June 2011 was ~364 MMCF, but monthly production had declined from ~70 MMCF in November 2010 to ~21 MMCF in June 2011. Gasco Production Co. received drilling permits in May 2010 for two horizontal tests of Mancos zones, the 42-17H-11-15 Gate Canyon Federal and 32-22H-11-15 Gate Canyon Federal wells in Duchesne County, but have not begun drilling as of this report. Until specific stratigraphic zones with favorable reservoir properties have been identified, horizontal drilling in the Mancos will probably be limited.

Current production from the Mancos Shale in the Uinta Basin is modest, but increasing as a result of recent drilling campaigns. In addition to XTO, these include QEP Resources, Wind River Resources, Newfield, and Gasco. In October 2011, Gasco staked two deep vertical wells, projected to ~17,000 feet in the Mancos, in southeastern Duchesne County near their Middle Bench field, which produces from formations overlying the Mancos.

New Research: In November 2011, the Utah Geological Survey (UGS) and its partners, the University of Utah and Halliburton Energy Services, will complete the first year of a three-year project to evaluate the resource potential and best practices for the Uinta Basin Mancos Shale gas play, funded by the Research Partnership to Secure Energy for America (RPSEA). Accomplishments to date include detailed descriptions and geochemical analysis of Mancos cores, petrophysical modeling and testing, identification of 3-D seismic horizons, assemblage of a log and literature database, and initial sequence-stratigraphic log interpretation. Preliminary results were presented in June 2011 to a Technical Advisory Board made up of representatives of companies actively or potentially operating in the Uinta Basin. Under the sponsorship of PTTC, a core workshop was held at the UGS's Utah Core Research Center in July 2011. Additional information about the project is at its website: http://geology.utah.gov/emp/shalegas/cret_shalegas/index.htm.

Recent Presentation:

"Integrated sedimentary, geochemical, and geomechanical evaluation of the Mancos Shale, Uinta Basin, Utah," by Lauren P. Birgenheier, Cari Johnson, Angela Kennedy, Brendan Horton, and John McLennan, all of the University of Utah, at the AAPG Annual convention and Exhibition in Houston, Texas, April 2011.

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Utica Shale (Ordovician), Appalachian Basin, U.S.

By Rich Nyahay

OVERVIEW:

The Ordovician Utica (Indian Castle), Dolgeville, and Flat Creek are the formations of interest. These shales and interbeded limestones range in TOC from 1- 5% in the dry gas window. They cover an area from Mohawk Valley south to the New York State boundary line with Pennsylvania and extend west to the beginning of the Finger Lakes region and east to the Catskill Mountain region. These three formations have a total thickness from 700 to 1,000 feet.

In Ohio and Pennsylvania the Utica is underlain by organic rich Point Pleasant Formation that is in part the lateral equivalent of the upper portion of the Trenton limestone and is in the gradational relationship with the overlying Utica shale which thickens into the Appalachian Basin. (Wickstom, 2011). The Utica – Point Pleasant interval is up to 300 feet thick in Ohio and over 600 feet thick in southwestern Pennsylvania. The TOC in this interval ranges from 1 to 4 % (Harper, 2011). In Ohio, gas prone areas will be found in the deeper parts of the basin well as appreciable amounts of oil (Ryder, 2008).

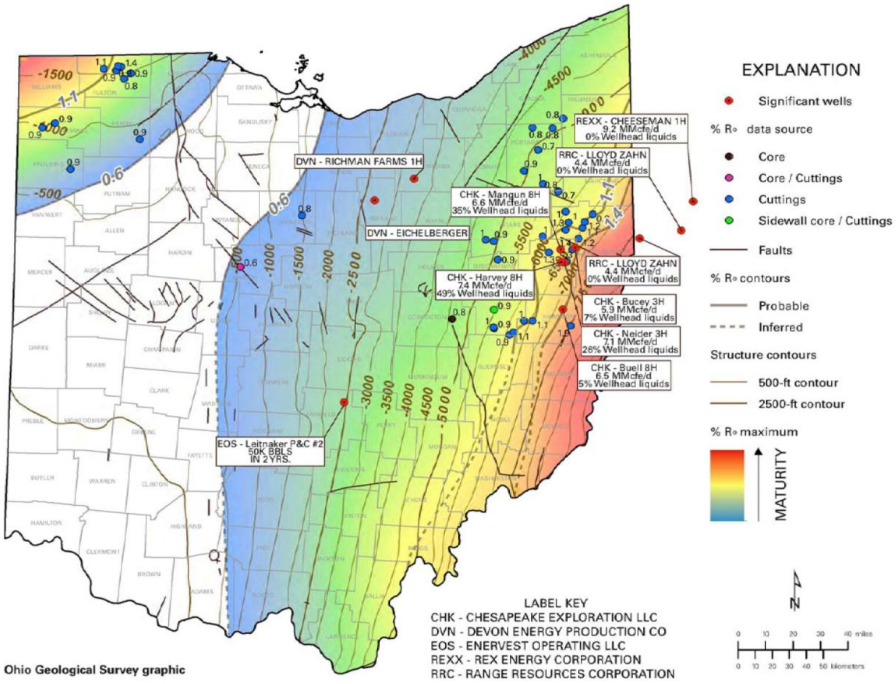
To date these formations have not been correlated from Ohio to New York, but a new consortium might be able to form a collaboration of industry partners and state geological surveys to spur a better understanding of these formations and their reservoir characteristics.

CURRENT:

With the current regulatory moratorium in place in New York, activity has been focused in eastern Ohio and western Pennsylvania. In March 2011, lease rates in the current active area were less than 2000.00 per acre, now the lease rates are reportedly in the range of 6000.00 per acre (Morris, 2012). According to the Ohio Department of Natural Resources Division of Oil and Gas Management website as of 3-18-2012 176 horizontal wells have been permitted and 53 have been drilled.
http://www.ohiodnr.com/portals/11/oil/Utica.xls

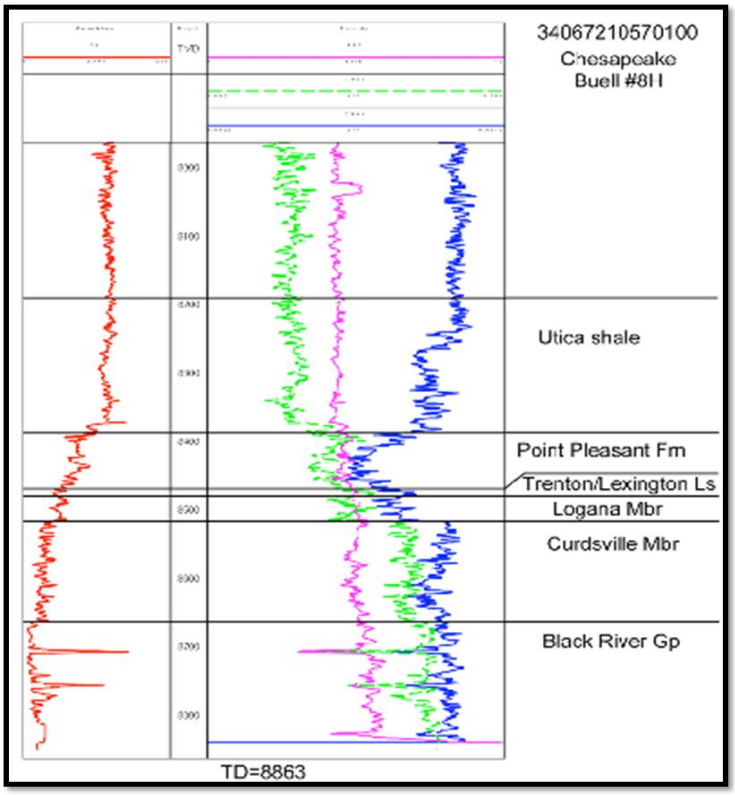
The Buell 10-11-5 8H in Harrison County, Ohio was drilled to a lateral length of 6,418 feet and achieved a peak rate of 9.5 million cubic feet (mmcf) per day of natural gas and 1,425 barrels (bbls) per day of natural gas liquids and oil (liquids), or 3,010 barrels of oil equivalent (boe) per day (Chesapeake Press Release 9/28/2011). Production report on this well is due to be released at the end of March, 2012. Rex Energy, in January, brought the first Pennsylvania Utica well into commercial production. The well in Butler County had a lateral length of 3551 feet completed in 12 fracture stages. The well yielded a stabilized 24 hour test rate of 9.2 million cubic feet a day of dry gas(Morris, 2012). Research in Ohio is moving forward to delineate the areas of oil, wet gas and dry gas by compiling all source rock analyses available in the state.

http://www.ohiodnr.com/Portals/10/Energy/Utica/Utica_SourceRock_Analysis_Data_12_13_2011.xls



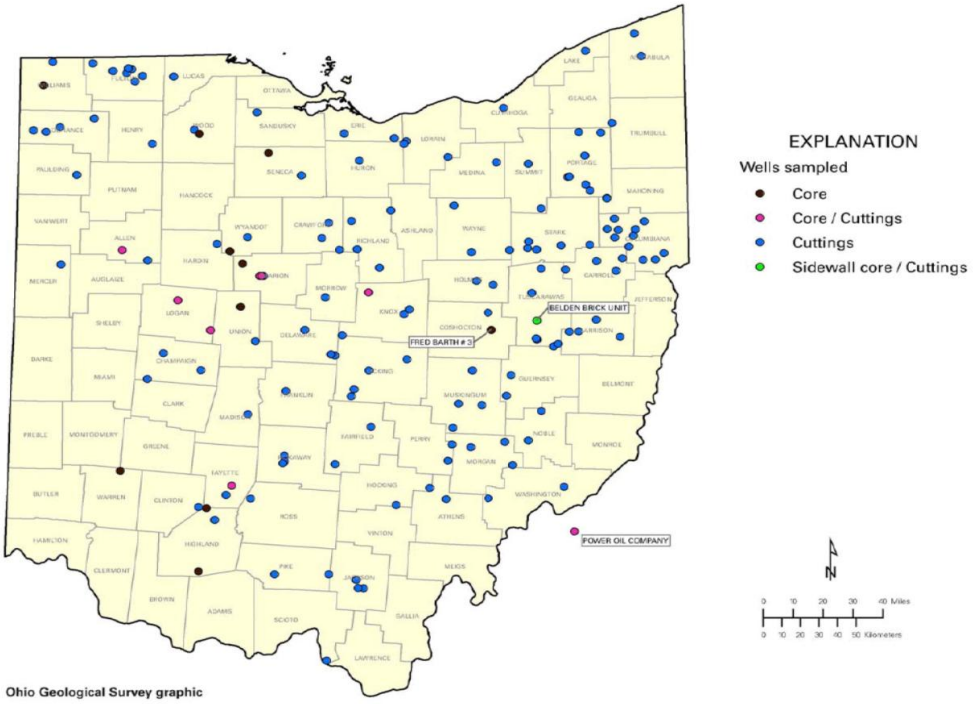
(Wickstrom et al. 2012)

Preliminary Map of Equivalent Ro Maximum per Well Overlain on Trenton Structure Contours & Significant Wells and IPs



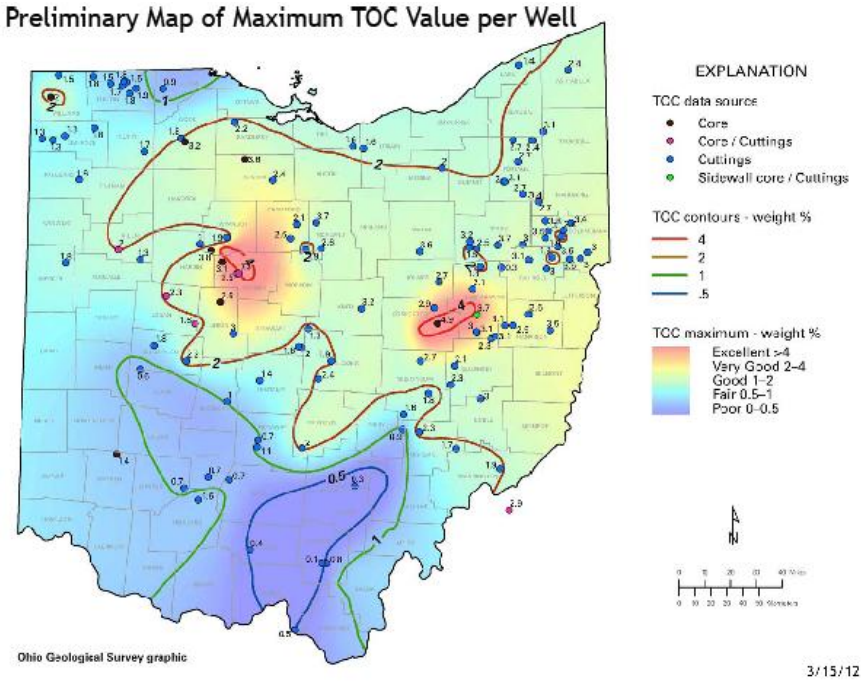
(Wickstrom et al. 2012)

Log of the Buell 8H well

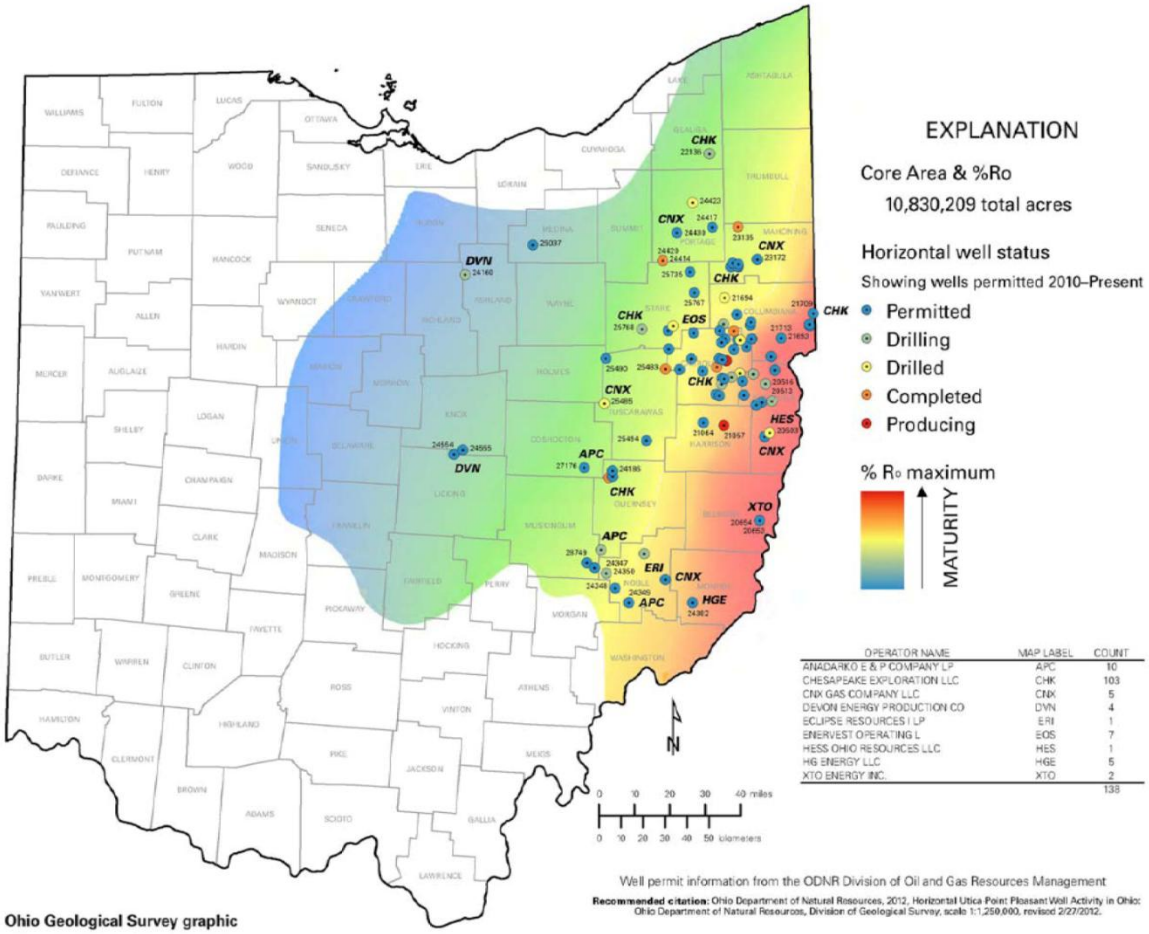


(Wickstrom et al. 2012)

All wells with Utica-Point Pleasant Source Rock Analyses in Ohio



(Wickstrom et al. 2012)



(Wickstrom et al. 2012)

Current Horizontal Well Permit and Completion Activity Overlain on Equivalent Ro Max Color Ramp and Defined Core Area

WEB SITES:

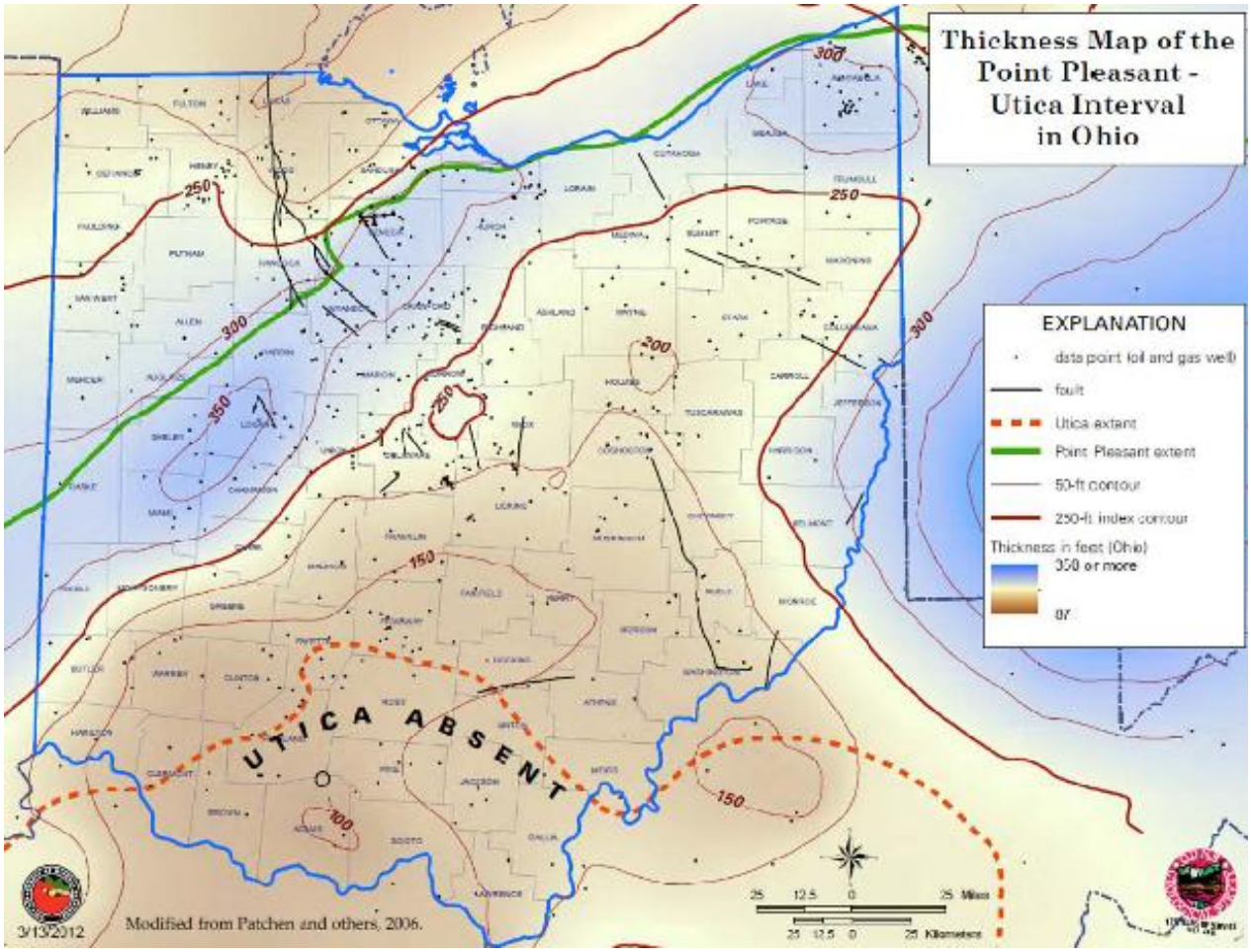
http://www.OhioGeology.com This website will lead you downloadable oil and gas data in Ohio as well as information on type logs, cores and instructions on how to download digital and raster geophysical logs.

http://esogis.nysm.nysed.gov This is the website to go for information on well logs, formation tops, core, and well samples. At this website many studies on New York reservoirs sponsored by NYSERDA can be downloaded for free.

http://www.dec.ny.gov/energy/205.html This is the website to find out information on wells being permitted, well spacing and all state regulations regarding oil and gas well drilling. This also the website to download the 1000 page draft Supplemental Generic Environmental Impact Statement.

ISSUES: On New Year's Eve a 4.0 earthquake shook Youngstown, Ohio and this followed nine months of seismic activity in the area. After an investigation the seismic activity was linked to an injection well the Northstar No1 which began operations in December of 2010. The well is one of 177 injection wells operating in Ohio(Columbus Dispatch, January 9, 2012). An unknown fault in the Pre Cambrian formation went unnoticed by regulators due to incomplete submittal of geophysical logs. As a result of this

investigation, future injection wells into the Pre Cambrian will be banned and existing Pre Cambrian injection wells will be plugged. State of the art pressure and volume monitoring will be required, including automatic shut off systems. Electronic tracking systems will be required that identify the makeup of all drilling wastewater fluids entering the state (Wall Street Journal, March 9, 2012).
In mid February New York Governor Cuomo stated in a Post Standard interview that a decision on hydrofracking could come down in a couple of months and the NYDEC commissioner also stated that a extremely limited number of fracking permits could be issued this year(Times Herald Record, February 12, 2012)



(Wickstrom et al. 2012)

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Woodford Shale (Late Devonian-Early Mississippian), Anadarko, Arkoma, and Ardmore Basins, U.S.

by Brian Cardott (Oklahoma Geological Survey).

The Oklahoma Geological Survey has a database of all Oklahoma shale gas and oil well completions. The database of 2,171 well completions from 1939 to the present contains the following shale formations and number of completions: Arkansas Novaculite (3), Atoka Group shale (1), Barnett Shale (1), Caney Shale or Caney Shale/Woodford Shale (96), Excello Shale/Pennsylvanian (2), Sylvan Shale or Sylvan Shale/Woodford Shale (8), and Woodford Shale (2,035). Shale wells commingled with non-shale lithologies are not included. Exceptions include 15 Sycamore Limestone/ Woodford Shale completions, 8 Mississippian/Woodford Shale, and 2 Hunton Group carbonate/Woodford Shale horizontal completions

where non-Woodford perforations were minimal. The database was originally restricted to shale gas wells. Shale oil wells have been added since 2004. Figure 1 illustrates 2,166 Oklahoma shale gas and oil well completions (1939–2011) on a geologic provinces map of Oklahoma.

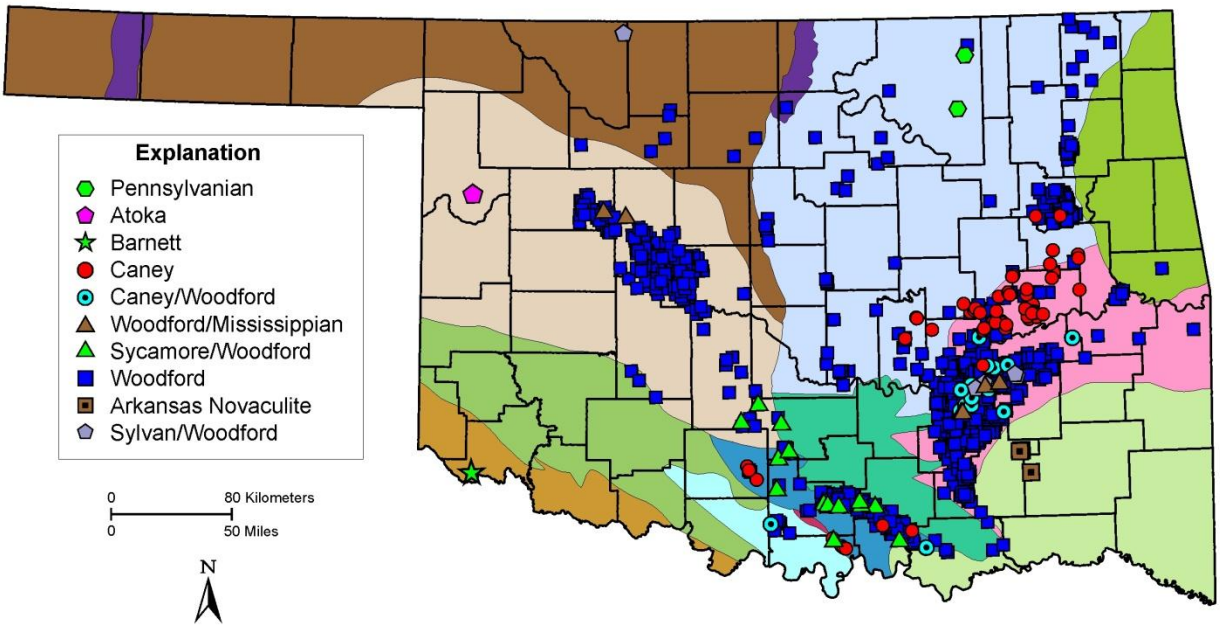


Figure 1. Map showing Oklahoma shale gas and oil well completions (1939–2011) on a geologic provinces map of Oklahoma.

Since 2004, the Woodford Shale-only plays of Oklahoma have expanded from primarily one (Arkoma Basin) to four geologic provinces (Anadarko Basin, Ardmore Basin, Arkoma Basin, and Cherokee Platform) and from primarily gas to gas, condensate, and oil wells (Figure 2). The recent low price of natural gas has shifted the focus of the plays more toward condensate ("Cana" play in the Anadarko Basin northeast shelf and western Arkoma Basin) and oil (northern Ardmore Basin) areas. Of the 2,005 Woodford-only well completions from 2004–2011, 123 wells are classified as oil wells and 1,621 wells are horizontal wells. Vertical depths range from 388 ft (Mayes Co.) to 15,321 ft (Caddo Co.). Initial potential gas rates range from a trace to 12 million cubic feet per day. Initial potential oil/condensate rates range from a trace to 418 barrels per day.

The annual peak of 534 wells occurred in 2008 (Figure 3). Following the drop in natural gas prices in 2008, the emphasis in the Woodford Shale plays is for oil- and condensate-producing wells. Figure 4, showing Woodford Shale wells from 2009–2011, illustrates the expansion of the Woodford Shale condensate play in the Anadarko Basin which began in Canadian County ("Cana") in 2007.

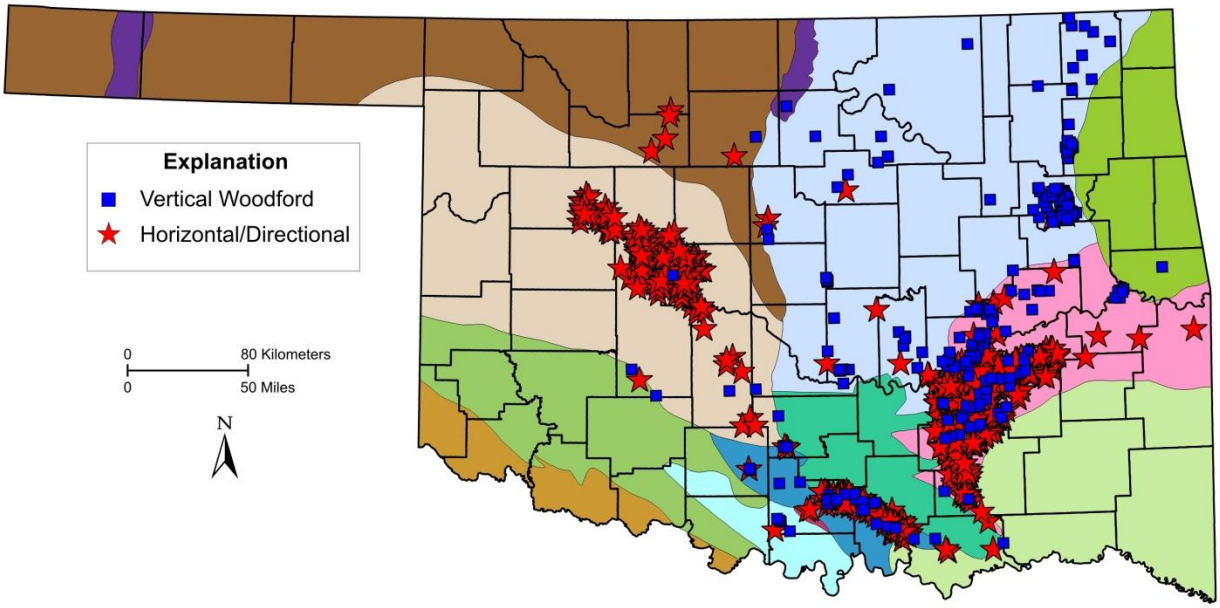


Figure 2. Map showing 2,005 Woodford Shale-only gas and oil well completions (2004–2011) on a geologic provinces map of Oklahoma.

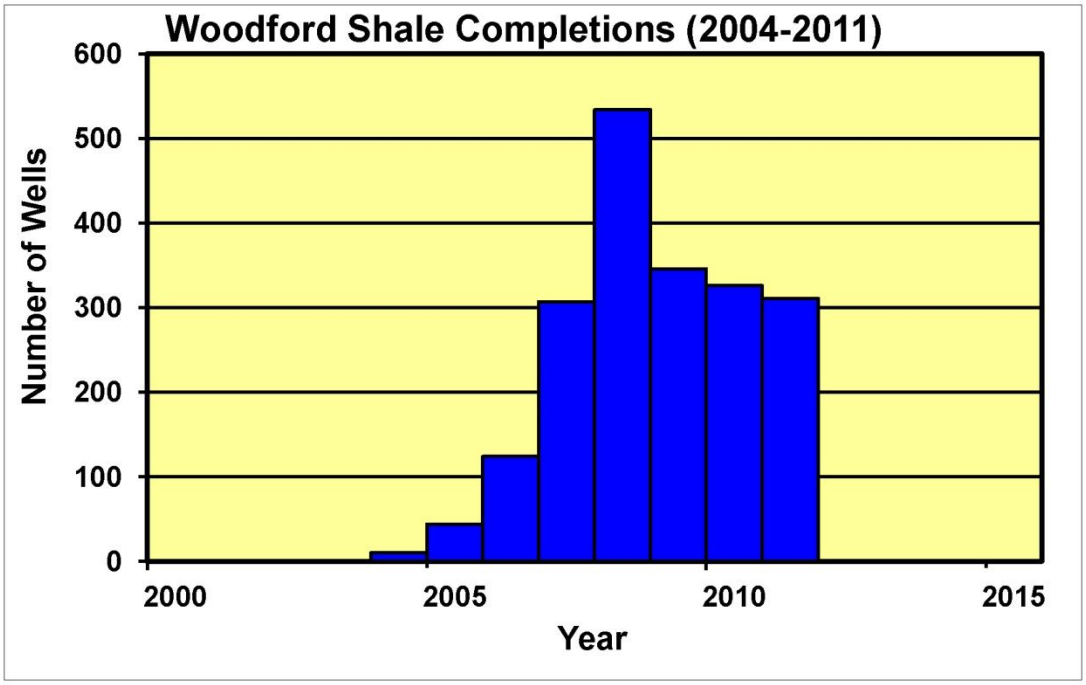


Figure 3. Histogram showing numbers of Woodford Shale-only well completions, 2004–2011.

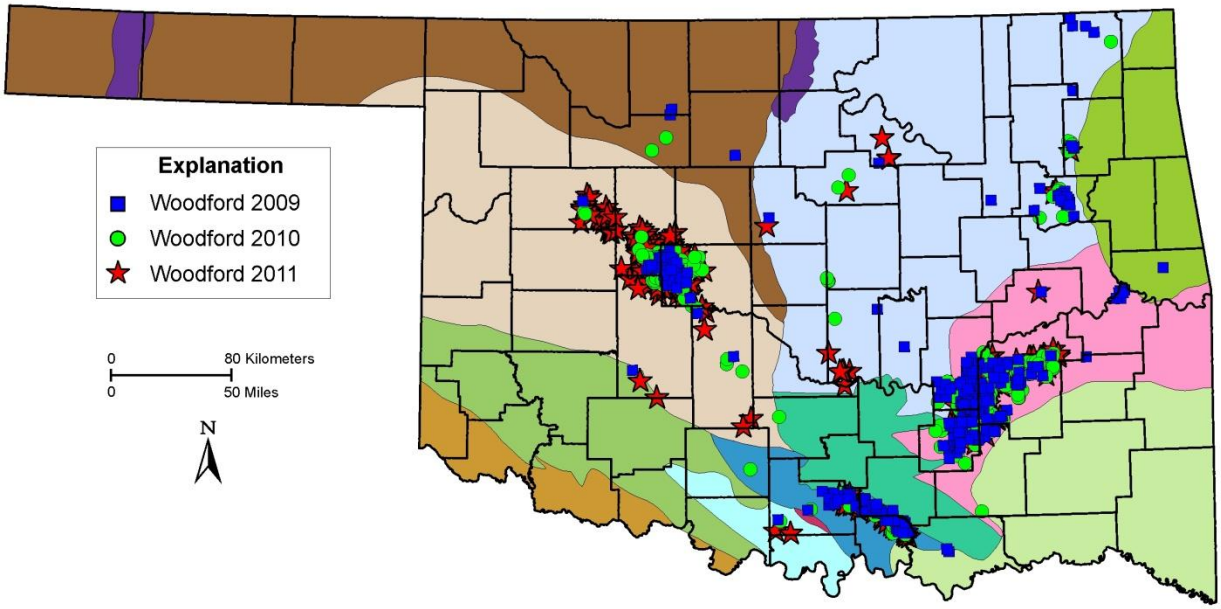


Figure 4. Map showing Woodford Shale-only gas and oil well completions (2009-2011) on a geologic provinces map of Oklahoma.

The four Woodford shale plays in Oklahoma are as follows:
1) western Arkoma Basin in eastern Oklahoma with thermogenic methane production at thermal maturities from <1% to >3% vitrinite reflectance (VRo) and condensate production up to @1.67% VRo;
2) Anadarko Basin shelf ("Cana" play) in western Oklahoma with thermogenic methane production at thermal maturities from 1.1% to >1.6% VRo and condensate production at thermal maturities up to @1.5% VRo;
3) Ardmore Basin in southern Oklahoma with oil and thermogenic methane production at thermal maturities in the oil window (<1.2% VRo);
4) Wagoner County (Cherokee Platform, northeast Oklahoma) with biogenic and thermogenic methane production at thermal maturities <1.2% VRo.

Of 37 operators active during calendar year 2011, the top nine operators (for number of wells drilled during 2011) are:

(1) Devon Energy Production Co. LP (90)
(2) XTO Energy (52)
(3) Cimarex Energy (26)
(4) Newfield Exploration Mid-Continent Inc. (23)
(5) Continental Resources (20)
(6) Petroquest Energy (20)
(7) BP America Production Company (16)
(8) QEP Energy Company(10)
(9) Range Production Company (9)

For additional information, visit the Oklahoma Geological Survey web site (http://www.ogs.ou.edu/level3-oilgas.php).

Canadian Shales

By Jock McCracken (Egret Consulting)

Even though Canada has an abundance of conventional oil and natural gas unconventional gas and oil dominate the headlines. Shale gas production in Canada is four years old after the announcement of new discoveries at the beginning of 2008. The state of development for the shale plays range from speculative to exploratory to emerging with only two giant plays, Horn River and Montney, in N.E. B.C. being considered developing and under increasing production. In most cases, the majority of these wells are still confidential so production numbers are unknown. Typically, production numbers from government websites are up to one year or more behind. Additional production numbers and exploration statistics for this report are therefore gathered from press releases and presentations from some of the key companies involved with the plays. As a result of the low gas prices operators have been focusing exploration and production into the liquids-rich hydrocarbons, if possible within their areas.

Recently there have been some new exciting discoveries in Alberta within the liquids-focused Duvernay and Alberta Bakken.

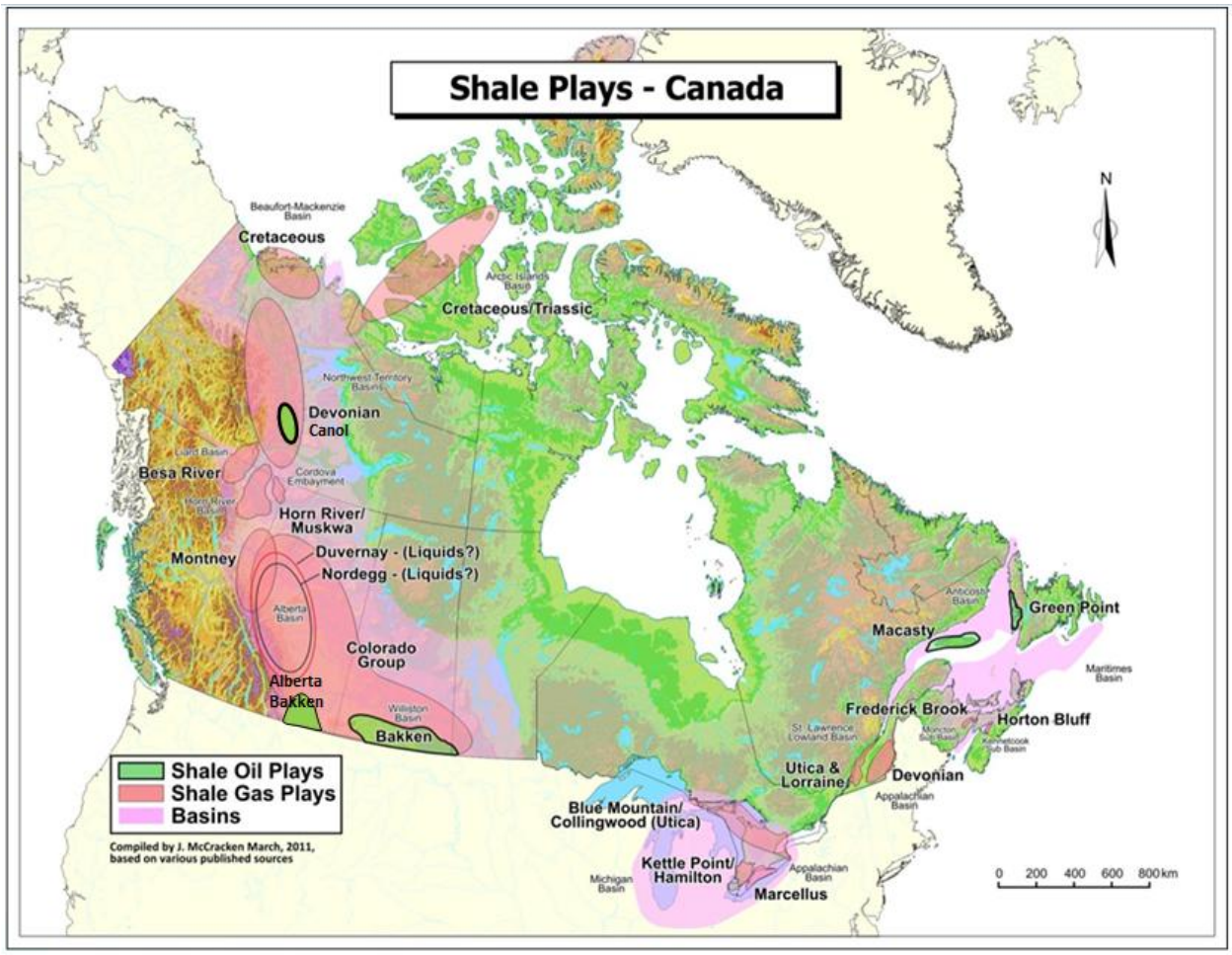
The Bakken oil play in Saskatchewan and Manitoba is still one of the hottest plays in Western Canada.

Significant shale gas wells have been drilled and tested in the St. Lawrence Lowlands of Québec but a government freeze on fracking because of about environmental concerns will slow down any future exploration and production. The positive announcements out of New Brunswick have been tempered by recent disappointing results and low gas prices.

To date there is shale exploration activity in 9 provinces of Canada out of the 10 with Prince Edward Island being the exception. One of the three Territories of Canada, the Northwest Territories, is just now seeing the drilling of their first wells into a possible oil-bearing shale section.

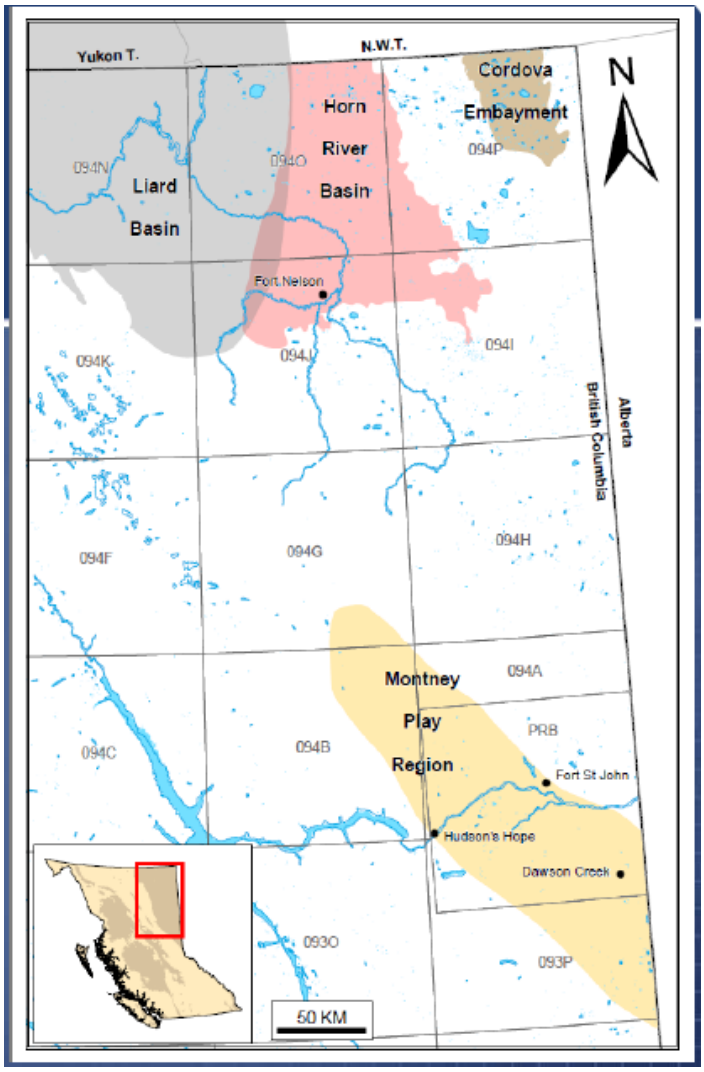
As a further note, there has been significant public concern in the press about hydraulic fracturing in various locations across Canada which is hindering or slowing down exploration and/or production. These concerns, especially in Provinces where there is limited oil and gas exploration and production, are being with by greater transparency and self-imposed industry guidelines.
http://www.capp.ca/aboutUs/mediaCentre/NewsReleases/Pages/GuidingPrinciplesforHydraulicFracturing.aspx

As well, a number of provincial governments are reviewing these practices (Nova Scotia and New Brunswick) as well as updated their regulations (Alberta). It is hopeful, at the end of this discussion, hydraulic fracturing will be managed such that it will minimize potential risks and allow the public to have a balanced and realistic sense of the costs and benefits.
http://www.montrealgazette.com/business/rules+practices+ease+fracking+concerns/6361034/story.html



NORTHEAST BRITISH COLUMBIA

Shale gas interest has dominated the sale of petroleum and natural gas (PNG) rights from the province in the last four years with the Horn River Basin, the Cordova Embayment and the Montney Play trend generating the most interest. Recently the Liard Basin or Beaver River Area has come on to the radar screen with most of the basin almost entirely licensed. Land sale bonuses for these NE BC areas accounted $4.6 billion since the record year in 2008. The bonuses have reduced somewhat since then as the available land is reduced with $223 million collected in 2011. These Cretaceous to Devonian British Columbia shales are estimated to have the capacity to hold over 1,200 trillion cubic feet (TCF) of original gas-in-place.


Yukon T.
N.W.T.
Cordova
Embayment
N
Horn
River
Basin
094N
094O
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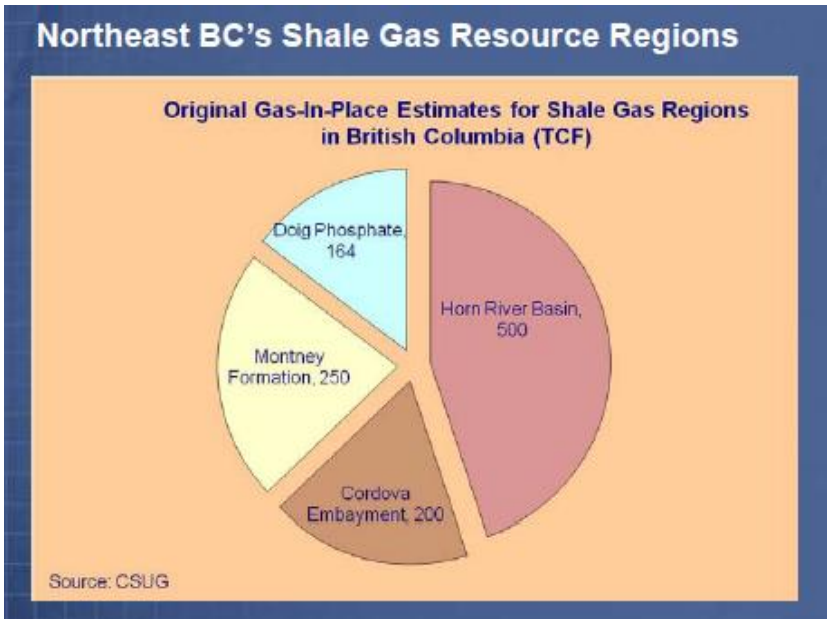
Liard
Basin
Fort Nelson
094K
094J
094I
British Columbia
Alberta
094F
094G
094H
Montney
Play
Region
094A
PRB
094C
094B
Fort St John
Hudson's Hope
Dawson Creek
093O
093P
50 KM

TABLE 1. POTENTIAL SHALE GAS FORMATIONS IN NORTHEAST BRITISH COLUMBIA

PROSPECTIVE HORIZONS

	Formations	Description	Depth	Average Thickness	Total Organic Carbon	Gas in Place
LOWER CRETACEOUS	Wilrich and Buckinghorse shales	Potential interbedded sand/siltstone	800 to 1,200 metres	100 metres	2.3%	**60 Bcf per section**
JURASSIC	Nordegg and Fernie shales	Recognized source rocks	1,200 to 2,500 metres	Up to 30 m organic rich section	up to 14%	**>20 Bcf per section**
TRIASSIC	Doig, Doig Phosphate and Montney	Montney turbidites may increase permeability Phosphate units have high TOC and are excellent source rocks	1,200 to 3,000 metres	300 to 500 metres	0.5 to >10%	**10 to 110 Bcf per section**
DEVONIAN	Exshaw, Besa River, Fort Simpson and Muskwa	Exshaw and Muskwa are widely distributed organic shales Fort Simpson and Besa River are thick basin-filling shales	1,800 to 3,500 metres	Huge thicknesses are common with some high TOC intervals	0.5 to >10%	**10 to 100 Bcf per section**



The chart below shows this activity in the NE B.C. The steep decline in 2009 reflects the economic downturn and the low gas price but despite this, activity is still proceeding.

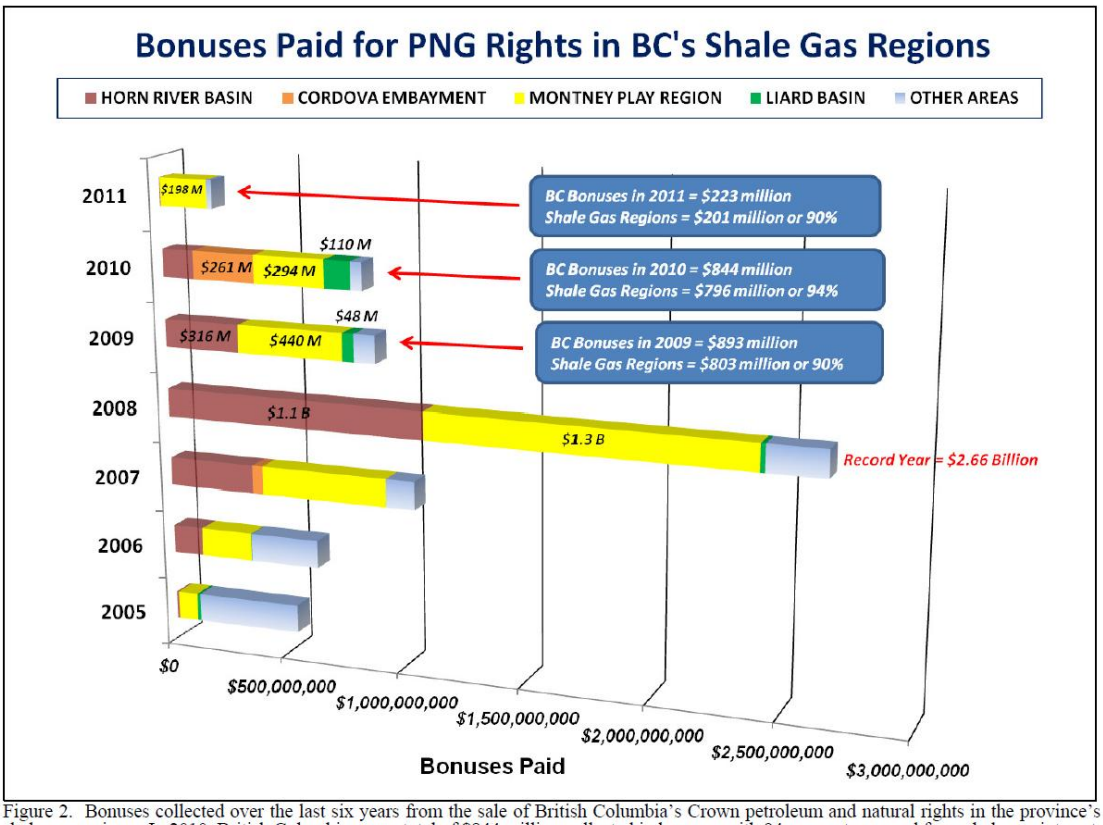


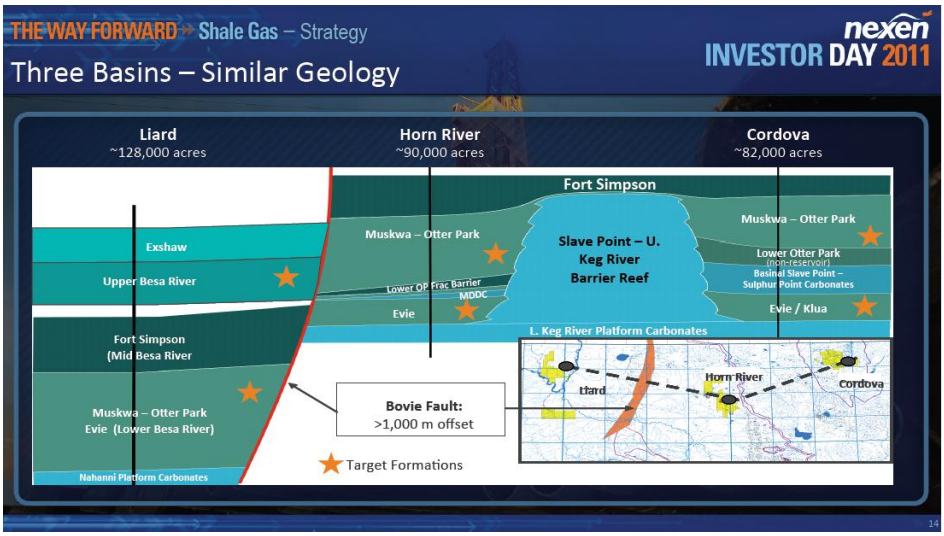
Figure 2. Bonuses collected over the last six years from the sale of British Columbia's Crown petroleum and natural rights in the province's shale gas regions. In 2010, British Columbia saw a total of $844 million collected in bonuses with 94 per cent amassed from shale gas interest. The Montney play region accounted for almost 89 per cent of the land sale bonus total in 2011.

Upper and Middle Devonian, Evie (Klua), Otter Park and Muskwa members of the Horn River Formation
Horn River Basin, Cordova Embayment and the Liard Basin

Of these very far north basins, the Horn River has the most activity. Recent government reports state that the Horn River production is, at year-end 2010, was approximately 392 MMCFD from 98 producing wells increasing from roughly 80 MMCFD at the end of 2009. The more recent 2011 wells are not published yet because of the confidentiality.

The following eleven operators form the Horn River Producers Group, which is a co-operative endeavor set up to share ideas and reduce the footprint: Apache, ConocoPhillips, Devon, EnCana, EOG Resources, Imperial Oil, Nexen, Pengrowth, Suncor, Quicksilver and Stone Mountain. There are another 15 companies working this area including SMR Oil and Gas, Taqa North, Storm Gas Resources, Canadian Natural Resources, Ramshorn Canada, Husky Oil and Delphi to mention a few.

The companies with the most acreage are Encana,260,000 ac, ExxonMobil, 250,000 ac, Apache, 220,000 ac, EOG, 157,000 ac, Quicksilver, 127,000 ac, Devon, 100,000 ac, Nexen, 88,000 ac, and Taqa North, 31,500 ac. (Hart E&P May 2011)



The five companies with the most drilling, as of end of 2011, are Apache, Encana, Nexen, EOG, Imperial Oil, Devon and Quicksilver.

Apache has been the most active since 2003. In 2010 they finished and started producing a 16 well pad with two more pads with another 42 wells coming on stream. Their production is 149 MMCFD as of Sept 2011.

Encana has drilled 68 shale wells since 2003 with 16 wells drilled in 2010. They lead the way with multiple fracture stimulations of up to 28 per well as well as the longest laterals of up to 3 kilometres long. Their forecast production for 2011, with 70 well online, is 100 MMCFD. Their forecast average production from this basin is expected to 600 MMCFD by 2014. Encana and Apache have entered into a partnership sourcing fracing water from the Mississippian Debolt Formation. Encana and Kogas Canada Ltd., a subsidiary of Korea Gas Corporation (KOGAS), have entered into a three-year exploration and production agreement with the first well pad expecting gas production this summer. Encana's $5.9 Billion partnership with PetroChina collapsed last June.

EOG completed 11 wells in 2010 but planning minimal drilling after that to hold the acreage. They recently drilled three wells testing and producing the Evie member at 16-22 MMCFD.

Nexen began fracture stimulation on eight wells in 2010 with production on stream. They also drilled a 9 well pad with that on stream as well. They expect to ramp up production to 50 MMCFD. They have a third pad with 18 wells coming on stream in late 2012. They could be producing 300 MMCFD by 2013. An agreement with the Japanese based INPEX and JGC Corporation to develop shale gas in the general Horn River area has recently been signed. Nexen have 128,000 acres of highly prospective shale gas lands in the Liard basin, with between 5 and 23 TCF of unrisked prospective resource.

Devon has the potential to produce up to 700 MMCFD based on its good land position and in the thickest part of the Basin. Seven horizontal wells were drilled in 2010 with nine wells producing currently at about 2 MMCFD. They are averaging about 1 MMCFD per frac stage.

ExxonMobil and its 50% partner Imperial Oil have been encouraged by their 10 plus wells over their large 320,000 acre position. They are therefore setting up a multi-well horizontal pad pilot development in one of their areas.

Quicksilver drilled 11 horizontal wells in 2011. Four of their wells are under production with one of them producing an average of 10 MMCFD since production was brought on in Oct of 2010. They are also planning to drill am oil rich horizontal leg into a section considered to be "Exshaw/Bakken zone" within the Horn River area.

The Laird Basin, which contains 3 million acres and a thick 5 kilometres of section from the Cambrian to the Upper Cretaceous, remains relatively unexplored. Apache drilled two experimental wells in this area but no reports of results yet. The only company where information is available is Transeuro Energy where they are proceeding to develop the pre-existing Beaver River gas field. They are continuing to develop this field with the hopes that the surrounding shales are feeding these reservoirs. Currently they are producing 2.7MMCFD. They plan to drill 6 more wells to target 14 horizons. Paramount has 125,000 acres of shale gas potential land.

The Cordova Embayment area, an area of 936,000 acres where most blocks of land were purchased in 2007, is now being drilled. B.C. has an experimental scheme ownership where operations are kept confidential for three years. Nexen, Penn West Trust and Canadian Natural Resources Ltd. have operations in this category with Nexen having drilled one vertical and one horizontal and Penn West Exploration planning 15 to 20 appraisal wells this year. Penn West just announced an $850 million Joint Venture with Mitsubishi to help develop their property in this area.

Recently, EnCana entered into an agreement with Enbridge Inc. for the sale of its majority stake at the Cabin Gas Plant in Horn River Basin for approximately $220 million. Phase 1 of the development will have 400 MMCFD of natural gas processing capacity. The plant is currently under construction and is expected to be in-service in the Sept 2012. Phase 2 will add an additional 400 MMCFD of capacity and has been sanctioned by producers and has received regulatory approval. The Phase 2 plant is expected to be ready for service in the third quarter 2014. Devon also has an interest in this facility.

Spectra Energy Corp. transportation system stretches from Fort Nelson, in northeast British Columbia and Gordondale at the British Columbia/Alberta border, to the southern-most point at the British Columbia/U.S. border at Huntington/Sumas. They have about 2,800 kilometres (1,700 miles) of natural gas transmission pipeline which can transport 2.4 BCFD.

TransCanada Corp. has filed an application for an Alberta pipeline extension subject to regulatory approvals, the approximate $310 million project is expected to be operational early in second quarter 2012 with commitments for contracted gas rising to approximately 540 MMCFD by 2014.

The Asian market is being targeted by Apache (40%), Encana (30%) and EOG (30%) with the building of an LNG terminal in Kitimat, BC, 643 kilometers north of Vancouver.

Plentiful supplies of gas have depressed North American gas prices below $3 per million BTUs where spot market LNG prices in Asia can be between $12 and $16 per equivalent unit. Kitimat LNG will source natural gas from the Western Canadian Sedimentary Basin and connect it with the dynamic liquefied natural gas (LNG) markets in Asia-Pacific, including South Korea, China and Japan, the largest importer of LNG in the world. Completion of the front-end engineering and design study and a final investment decision are targeted 2012. Construction is expected to commence in 2012, with commercial operations projected to begin in late 2015. The National Energy Board of Canada just granted this $15 Billion project a 20 year export license. This terminal will be fed by the proposed 300 mile (463 km) Pacific Trail Pipeline coming from N.E. B.C. Other proposals are slowly taking shape with more LNG terminals being proposed. Royal Dutch Shell Plc and partners Korea Gas Corp, Mitsubishi Corp and China National Petroleum Corp have also bought land for a potential LNG export terminal at Kitimat. Progress Energy Resources Corp and Malaysian joint-venture partner Petronas are carrying out a feasibility study for another project.

Triassic Doig and Montney

Fort St. John/Dawson Creek Area

The Montney is a tight gas/shale gas play and producing at approximately 1.38 BCFD at the end of October 2011. This Montney Play Trend, of 6.6 million acres, is now one of the most active natural gas plays in North America. The primary zones are the Upper Middle and Lower Montney as well as the Doig and Doig Phosphate. The major facies include fine-grained shoreface, shelf siltstone to shale, fine-grained

sandstone turbidites, and organic rich phosphatic shale. This play varies from the traditional distal shale facies along the Alberta/British Columbia border to a tight calcareous siltstone and sandstone in Central Alberta. The current trend for companies is to explore up dip towards the "oil window" in search of liquids-rich gas. The main Montney players in order of rig utilization are Shell Canada Ltd, Murphy Oil Co. Ltd, Talisman Energy Ltd., Encana Corp., Progress Energy Ltd., ARC Resources Ltd., Canadian Natural Resources Ltd, Tourmaline Oil Corp., Crew Energy Inc., Painted Pony Petroleum Ltd., Canbriam Energy Inc., Huron Energy Corp. as well as, at least, another 23 operators. This report will just cover the most active players.

Shell Canada Limited keeps expanding their program in the Sunset Prairie-Groundbirch area and has now reached 150 MMCFD from 225 wells on 40 pads. They believe that they have only tapped into 5% of their resource estimate of 8 TCF for the area.

Murphy Oil Corporation, in their Tupper Creek Area, has now reached a production level of over 250 MMCFD. They have almost 145,000 net acres in the Montney Trend and drilled 60 wells last year. Their Tupper West gas plant has the capacity of 180 MMCFD with the current production of 150 MMCFD from 59 wells.

ARC Resources Ltd. has now increased their daily production to 235 MMCFD and 1,800 barrels per day of liquids. They have stated that they could sustain rates of up to 800 MMCFD and 17,000 BPD of liquids for a period of 10 years based on their resource portfolio. The first two of three 60 MMCFD gas plants are on stream at full capacity. Some of their wells are producing 30 to 200 barrels per/MMCF. Another recent well of theirs is producing 4.7MMCFD from a 100 metre section in the Upper Montney.

Encana is one of the biggest players with 482 rig releases since 2005. They drilled 90 wells in 2009 with 8 to10 wells per section, 62 wells in 2010 and 43 in 2011. The horizontal section are up to 2400m long with up to 17 fracs per well with some recent IP at 10 MMCFD. They believe they have an estimated 70 TCF of gas in place in their trend. Their Montney, Cutbank Ridge area should be producing at the end of 2011 at 510 MMCFD with their current forecast for 2014 at 600 MMCFD. They have advanced their resource hub design to a new level with 8-12 wells per hub, 100-200 completions per hub, up to 17 stages per well, laterals of 650-100 ft., horizontals of 6500-10,000 ft. and completions every 450 ft. This has reduced their completion costs by approximately 60 % in the last 5 years. They have recently announced 40 % sale of some of their acreage in the area to Mitsubishi Corporation.

This play keeps expanding both aerially and stratigraphically as operators are searching for the more liquids-rich sections. Two other operators are partnering up with other international players where Progress Energy Resources Corp. created 50/50 partnership with the Malaysian PETRONAS and Talisman Energy Inc. partnered up with South Africa's Sasol Ltd. Other companies have reported liquid yields per MMCF of 20 BBL (Terra Energy Inc.), 30 BBL (Canadian Spirit Resources Inc.), 35 to 50 BBL (Tourmaline Oil Corp.), and 60 to 85 BBL Crew Energy Inc.) A very extreme gas rate of 24.5 MMCFD was announced by Painted Pony Petroleum Ltd.

The graph below shows the well production in the Montney from the Adams, 2012 report.

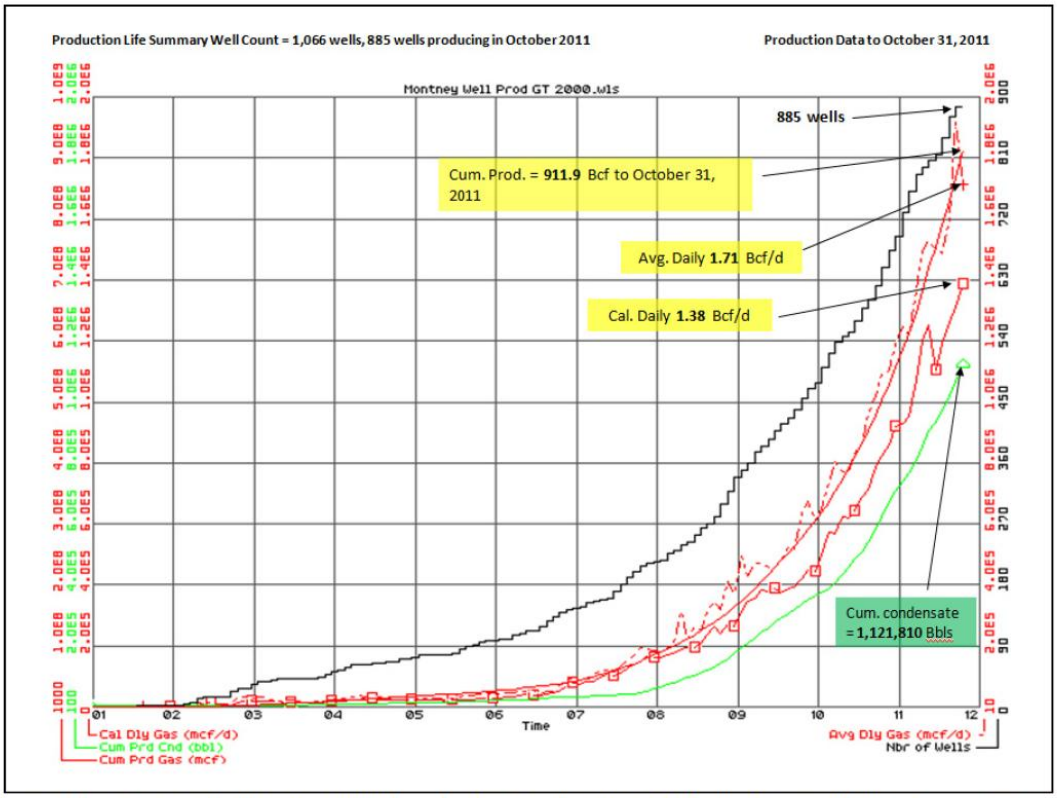


Figure 14. Approximately 912 Bcf of natural gas has been produced from the Lower Triassic Montney Formation from 2001 to October 2011. The average daily calendar rate in October 2011 was 1.38 Bcf per day from 885 producing wells. Cumulative condensate production to October 31, 2011 was 1,121,810 barrels.

Lower Cretaceous – Gething and Buckinghorse

N.E. British Columbia

Shale gas activity directed towards Cretaceous horizons is being assessed in several areas of the Fort St. John and Northern Foothills regions. The Blair Creek and Farrell Creek areas in the Northern Foothills region have seen a steady increase in the sale of petroleum and natural gas rights over the last four years. Lower Cretaceous sequences are the exploration focus in the Beg/Jedney areas and further south in the Blair Creek and Farrell Creek areas. Each of these areas has unique characteristics in terms of its shale gas potential. Companies currently operating in these areas are evaluating fracture stimulation programs and continue to optimize completion methods that could potentially increase well productivity.

Painted Pony Petroleum has 82,465 net acres of Buckinghorse potential with recompletion and testing of 3 wells and 2 more wells drilled. No production numbers announced yet as they experiment with drilling and completion techniques. Canadian Spirit is another player in the area, mostly with experimental schemes, on the Gething. No production volumes reported yet. Unconventional Gas Resources is experimenting with the Buckinghorse shale.

This link below summarizes news items concerning the Horn River area.

http://hornrivernews.com/

B.C Shale information link: There is a wealth of data on this website.

http://www.empr.gov.bc.ca/OG/OILANDGAS/PETROLEUMGEOLOGY/SHALEGAS/Pages/default.aspx

http://www.offshore-oil-and-gas.gov.bc.ca/OG/oilandgas/petroleumgeology/UnconventionalGas/Documents/C%20Adams.pdf

Adams, C. (2012): Summary of shale gas activity in northeast British Columbia 2011, BC Ministry of Energy and Mines, pages 1-19.
http://www.empr.gov.bc.ca/Mining/Geoscience/PublicationsCatalogue/OilGas/OGReports/Documents/2012/Summary%20of%20Shale%20Gas%20Activity%20in%20NEBC%202011%20Web.pdf

BC MEM/NEB Report, May 2011: Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin
http://www.em.gov.bc.ca/OG/Documents/HornRiverEMA_2.pdf
http://www.aapg.org/explorer/2010/10oct/regsec1010.cfm

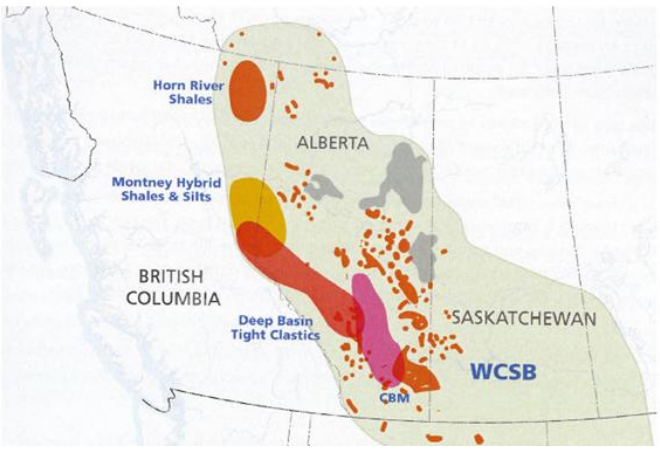
Geoscience BC

Geoscience BC is an industry-led, industry-focused, applied geoscience organization. Our mandate is to encourage mineral and oil & gas exploration investment in British Columbia though the collection, interpretation and marketing of publically available. Some of their major projects have been aquifer studies.

http://www.geosciencebc.com/s/AboutUs.asp

ALBERTA

Estimates of shale gas within the Western Canada Sedimentary Basin (see map below) vary from 86 to 1000 TCF. While there is a huge potential in Alberta, commercial shale gas production is at early stages but additional new plays have suddenly begun to emerge.



Alberta has extensive experience in the development of energy resources and has a strong regulatory framework already in place. Shale gas is regulated under the same legislation, rules and policies required for conventional natural gas. The Energy Resources Conservation Board (ERCB) regulates exploration, production, processing, transmission and distribution of natural gas within the province.

It is predicted that about two to eight shale wells will be drilled per section to effectively produce shale gas in Alberta. There can be multiple zones of potential in Alberta within a shale gas play, both from conventional and unconventional gas production. This could result either in commingling of gas zones or more than two to eight wells per section being drilled, subject to Energy Resources Conservation Board regulations

Cretaceous Colorado Group

Eastern Alberta

This play is potentially widespread but there has been limited shale gas activity and production within this interval mostly as a result of the gas price. The shale gas intervals are normally co-mingled so numbers are difficult to grasp for the shales. There have been small companies producing gas from this zone but they are limited and some are selling their interests. Some companies are now focusing on the liquids potential of the Second White Specs.

Lower Jurassic Nordegg (Gordondale)
West Central Alberta

Anglo Canadian Oil Corp. has been playing the potential of the Nordegg Member which is a source rock composed of basinal shales, silts and carbonates. They feel that the Nordegg Member contains a huge amount of oil. They are drilled a horizontal well to test this play producing limited liquids. Undoubtedly there are others in this play.

Triassic Montney Shale
Western Alberta

The Montney fairway extends in Alberta where this play is being picked up for both gas and liquids rich gas.

Devonian Duvernay/ Muskwa Shales
Western Alberta

The exciting new liquids play, Duvernay Shale is the stratigraphic equivalent to the Muskwa in N.E. B.C. Large land sale bids of $384 million at the end of 2009 triggered some speculation that the above shale may have been the target despite its 4000 m depth. This play may hold 25 TCF but infrastructure costs should be minimal since this area is just west of Edmonton. The government of Alberta has taken in lease payments exceeding $2 billion in the first 7 months of 2011.

Encana announced that their two wells produced 2 to 5 MMCFD and 158 to 390 bbl per day respectively. They have 5 wells planned for the first half of 2012. Talisman has two pilot wells in 2011 with two wells planned in 2012. They spent $510 million in June increasing their footprint to 360,000 acres. Chevron has picked up some acreage as well. Trilogy Energy completed two wells in the Duvernay Shale with test results from 2 to 5 MMCFD and 75 bbl of condensate per million cu ft.

Yoho Resources and Celtic Exploration are also playing this interval. Yoho sees 80-105 bcf/sq. mile of gas in place in shale 130-180 ft. thick with 7.1% average effective porosity and 1-4% total organic carbon. Other independents that hold Duvernay acreage include Mooncor Oil & Gas Corp., Galleon Energy Inc., Orleans Energy Ltd., and Delphi Energy Corp.

But while the Duvernay may be a rich resource, it is not cheap to produce. Fracking is very expensive being two-thirds or more of the cost of the $10 to $15 million per well. The wells are 3,000 m deep with a 2,000 metres horizontal leg, within a 100 metre thick zone. The Duvernay is liquids rich at approximately 75 BBL/MMCF.

In 2011, 17 horizontal and 13 vertical wells were drilled in the Duvernay and Peters and Company is forecasting 40 wells will be drilled in the play in 2012.

The small amount of drilling means producers haven't found the key yet, with Peters noting that the Duvernay's proximity to the foothills, the depths being drilled (anywhere from 2,200 to 3,800 meters) and higher than average fracture gradients and reservoir pressures means operators will continue to face drilling and completion challenges. "Overall, given the few Duvernay wells drilled to date, well completions for this zone are in the experimental phase," Peters writes.

Experimentation is also costly. Peters says well costs in the play have been between $10 million and $20 million per well. http://www.albertaoilmagazine.com/2012/03/duvernay-play-challenging-but-promising-peters-co-says/

Late Devonian and Early Mississippian Alberta Bakken - Exshaw
Southern Alberta

The Alberta Bakken (Exshaw) is an emerging tight oil resource play in SW Alberta to NW Montana consisting of three zones, Big Valley / Steller Carbonates, Bakken /Exshaw dolomitic siltstones and Banff carbonates. This play gained momentum south of the border in Montana and has recently emerged into Alberta and there is rush to get a position. There are a number of companies in this play. Over 30 horizontal wells have been drilled so far but with little publication of results. Crescent Point, Shell, Murphy, Argosy, Nexen, Bowood/Legacy, Rosetta and Newfield are some of the companies involved. Crescent Point Energy has 1,000,000 acres, drilled three wells and with 14 wells planned for 2011. Production of about 300 to 350 BOPD has been published. Murphy is drilling 6 to 9 wells with 5 drilled to date: 3 producers, one being evaluated and I awaiting completion.

http://www.primarypetroleum.com/pdf/PIE_Industry_News_2011-03-10.pdf

The Alberta Energy Resources Conservation Board (ERCB) just recently published a document to clarify the definition of shale for shale gas development and to identify the geological strata from which any gas production will be considered to be shale gas.

http://www.ercb.ca/docs/documents/bulletins/Bulletin-2009-23.pdf

Alberta Energy Shale Gas http://www.energy.alberta.ca/NaturalGas/944.asp

The Alberta Geological Survey (AGS) is active in publishing geological studies including a number of studies on shales.

AGS Shale Gas Section
http://www.ags.gov.ab.ca/energy/shale-gas/shale-gas.html

AGS Reports http://www.ags.gov.ab.ca/publications/pubs.aspx?tkey=shale%20gas

AGS Conference Papers and posters
http://www.ags.gov.ab.ca/conferences/geology-poster-ppt.html

Alberta Duvernay/Muskwa and Montney Formations Shale Analysis poster by the ERCB and Alberta Geological Survey.

http://www.ags.gov.ab.ca/conferences/shale_gas_cspg_2009_poster.pdf

The Alberta Geological Survey has this link with documents on the Colorado Play.
http://www.ags.gov.ab.ca/publications/pubs.aspx?tkey=colorado%20group

The ERCB is the regulator for Alberta. http://www.ercb.ca/portal/server.pt

SASKATCHEWAN

Upper Cretaceous Colorado Group – biogenic gas
Central Saskatchewan

As in Alberta the Colorado Group shales have been produced in Saskatchewan at low volumes for a 100 years but the recent gas price decline has kept this play minimized. In this province, the past exploration focus has been primarily on two types of biogenic shale gas potential within the Upper Cretaceous. The first type is a hybrid shale gas play along the Saskatchewan–Alberta border, where thin laminae of sand and silt lie within the shales of the Upper Colorado Group. Other intervals within the Colorado Group that were once lumped and dismissed as ‘non-productive shale’ are also now being re-evaluated. The second type of play currently being evaluated is the Colorado shale gas play in the eastern half of the province. These highly organic shales have been the focus of exploration in the past, prior to World War II, when gas seeps were reported near the towns of Kamsack and Hudson Bay. Several wells near Kamsack produced from the early 1930s to late 1940s with total gas production of 168 MMCF. From 2001 to September 2008, 59 new wells, licensed for gas, were drilled in the Hudson Bay and Kamsack areas.

There are still no major commercial discoveries and not much news out of Saskatchewan this year as a result of the lower gas price and the economy. There are however around 13 wells in SW Saskatchewan that under production from the Colorado shales.

Between 2004 and 2008 more than 50 test wells were drilled for shale gas in all areas in the province, including Watrous, Moose Jaw, Strasbourg, Foam Lake, Smeaton, Shell Lake and Big River but no commercial discoveries have been announced. Some players are still operating, but at reduced or no activity.

http://www2.canada.com/reginaleaderpost/news/business_agriculture/story.html?id=c41a6b5b-b892-40cc-8cb4-902156681111&k=18412

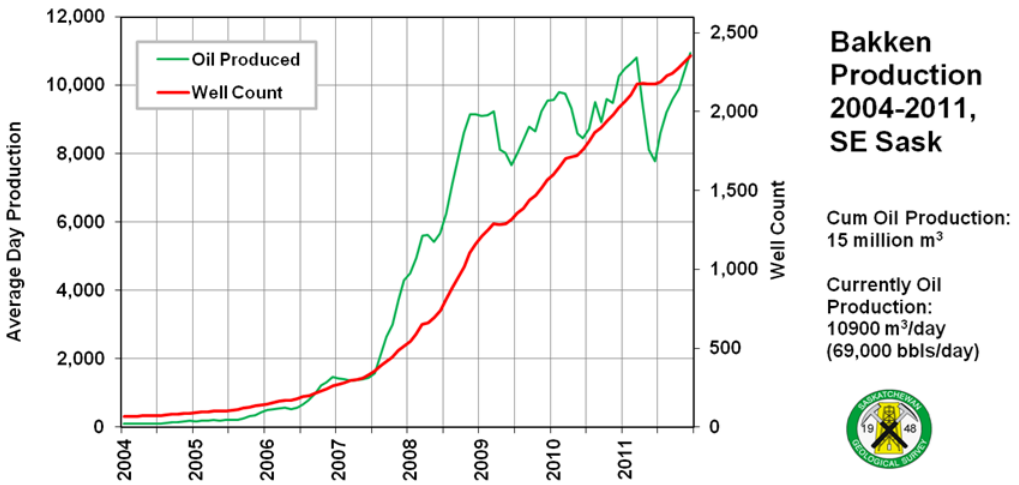
PanTerra Resource Corp. have drilled and cased thirty-six wells within their more than one million acres of land. They feel they have 3 TCF of recoverable gas. They had been coring, logging and fracture stimulating but no rates have been announced to date. Because of the low gas prices they have put this project on hold.

There has also been some activity in the Pasquia Hills in central east Saskatchewan. Pasquia Hills has a huge potential for Oil Shale in this area but there have been about 23 wells drilled by various operators with gas shows and some limited gas tests. Nordic announced recently that survey work has now commenced for a five-well drilling program on the Company's land in Preeceville. Nordic believes that with new drilling technology available, it will be successful in unlocking the enormous reserves of shale and natural gas. After drilling two unsuccessful wells they will be returning in the fall for another well. It is unclear whether this play is unconventional or conventional or both with both gas and oil as their targets.

Recently Questerre announced a Pasquia Hills program. They acquired 100% interest in over 100,000 acres at Crown land sales with a 2-year work program. Situated in one of Canada's largest oil shale deposits with plans of a 2012-2013 work program to include core holes and trenching to assess potential. They have partnered up with a USA firm uses the EcoShale In-situ capsule process which is an innovative approach that moves the machines to the rocks instead of moving the rocks to the machines to extract the oil.

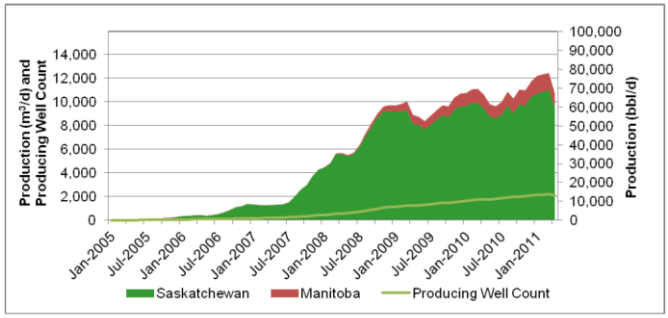
Upper Devonian- Lower Mississippian Bakken

Saskatchewan is also reaping the benefits of the boom in horizontal and fracturing techniques drilling, especially in the Bakken. Production has risen from about 1-2,000 BOPD in 2005 to about 50 to 60,000 BOPD at the beginning of 2010. The Bakken production comes from the tight siltstone and sandstone beds with in the shales (Kreis, L.K. and Costa, A. 2005) so it is not really a shale oil play. The Bakken wells tend to highly productive at 200 BOPD producing a t light sweet crude oil with 41 API gravity. There are many players in this zone. One of the two bigger players are Crescent Point with 704,000 net acres, 3,800 drilling locations, 154 wells to be drilled in 2012 and 4 Billion BOIP. Currently they are producing at 42,000 BPD. PetroBakken is the other one with 275,200 net acres, 750 net drilling locations and about 20,000 BPD.



The following chart came from the publication "Tight Oil Developments in the Western Canada Sedimentary Basin" by the NEB, Dec 2011.
http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/l/tghtdvlpmntwcsb2011/tghtdvlpmntwcsb2011-eng.pdf

Figure A.12. Bakken, Three Forks, and Torquay Tight Oil Production by Province.



Data Source: Divestco

Saskatchewan Government energy and resources is the regulator.
http://www.er.gov.sk.ca/Default.aspx?DN=4c585c56-193a-485a-91fd-7c49f0104a60
http://www.wbpc.ca/assets/File/2011%20Presentations/Tuesday/Nickel%20wbpc%2011%20Bakken%20Talk.pdf

MANITOBA

Cretaceous Colorado Group

There is the potential of shale gas in Manitoba, but no activity or production. There have been a number of publications on the shallow shale potential by Nicholas and Bamburak.
http://www.wbpc.ca/assets/File/Presentation/11_Nicolas_Manitoba.pdf and Nicholas 2011
http://www.wbpc.ca/assets/File/2011%20Presentations/Tuesday/Nicolas%20WBPC%202011_Shale%20gas%20to%20Three%20Forks.pdf

Upper Devonian-Lower Mississippian Bakken

The production of oil from the Bakken, which began in the mid-1980's, continues, with about 14,700 BOPD from the formation, a tenfold increase since 2005. Total oil production in 2010 was a record 1,871,207.8 m3 – 11.7 million Barrels. The month of Dec 2010 had the highest production on record – 190,595.7 m3 (1.2 million barrels) or 38,692 barrels per day. Total production for first quarter 2011 was 587,887 m3 - 3.7 million barrels or 41,108 barrels of oil per day.

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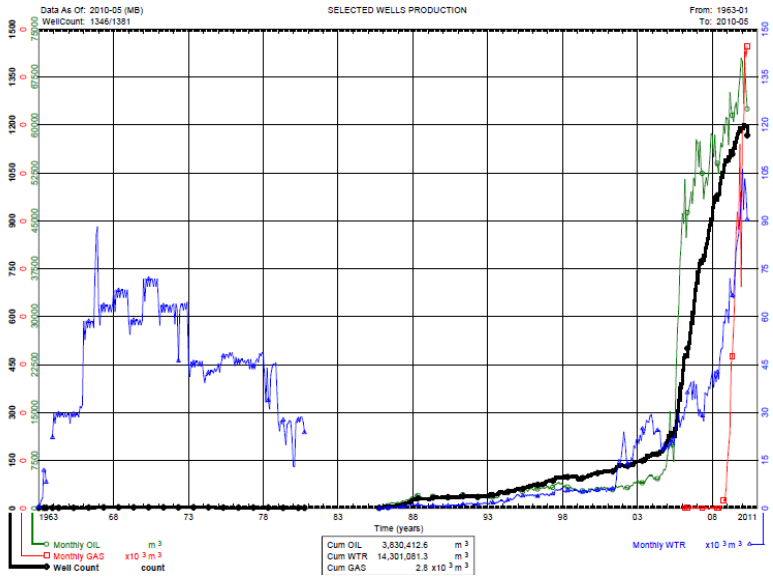


The Manitoba oil and gas is the regulatory agency. http://www.gov.mb.ca/stem/petroleum/index.html
Manitoba Mineral Resources
http://www.manitoba.ca/iem/mrd/index.html
Manitoba Geological Survey
http://www.manitoba.ca/iem/mrd/geo/index.html

ONTARIO

Upper Devonian Kettle Point Shale (Antrim Shale Equivalent)
Middle Devonian Marcellus Shale
Upper Ordovician Blue Mountain and Collingwood Shale (Utica Equivalent)

Exploitation of these shales has been very quiet with only a few operators discussing the evaluation of these shale targets. These shales are mostly considered secondary targets but only one well has been drilled to test these zones to date. Mooncor has just locked up about 23,000 acres of shale gas potential.

The only drilling activity is by the Ontario Geological Survey. They drilled two stratigraphic tests last year to assess the shale gas potential of the Kettle Point Formation. They have just released a request for proposals to drill two more stratigraphic test wells to test the Collingwood-Blue Mountain. No results have been published yet.

The Ministry of Natural Resources of Ontario is the regulator.
http://www.ogsrlibrary.com/government_ontario_petroleum.html
http://www.ogsrlibrary.com/downloads/Ontario_Shale_Gas_OPI_2009_Nov11.pdf
http://www.wnloilandgas.com/media/uploads/Carter_Presentation.pdf
http://www.ogsrlibrary.com/

QUEBEC – ST. LAWRENCE LOWLANDS

Ordovician Lorraine and Utica Shale

The other potential bright light in Canadian shale exploration in 2008 was in Quebec, within a 300 km by 100 km fairway between Montreal and Quebec. The Upper Ordovician Utica and Lorraine shales are the targets.

On March 8 2011, the Quebec Provincial Government effectively declared a temporary moratorium on the use of chemical fracturing during shale gas drilling pending stricter a full environment assessment audit. http://www.bape.gouv.qc.ca/sections/rapports/publications/bape273.pdf in French only.

As well, no new wells will be drilled without local approval. This review conducted by a 11 person committee could take up to 30 months. The government had previously awarded permits for 29 drilling sites where fracking has taken place on 18 locations.

A year ago, when Quebec Environment Minister Pierre Arcand announced the $7-million Strategic Environmental Assessment (SEA) on shale gas, he said it was in part to reassure the public that shale gas development will not go ahead in Quebec unless it is determined to be safe.

But a year into that process, opposition remains as fierce as ever. The committee's final report is to be submitted to the government by November 2013.

http://www.montrealgazette.com/technology/year+later+opposition+shale+exploration+still+fierce/6327547/story.html#ixzz1qkV4IfFA

Industry has drilled or evaluated 23 wells and spent $200 million. Assuming a green light after the environment review finishes industry is saying that it would take 3 to 4 years before the production stage is reached.

Both Forest Oil Corporation and their partners and Talisman and their partners have drilled to evaluate both the Lorraine (up to 6,500 feet thick) and the Utica (300 to 1,000 ft thick). Talisman with their partners and a 771,000 acre land position has drilled six vertical wells with tested rates at from 300 to 900 MCFD. In

2009 and 2010 they drilled or will be drilling five horizontals which were currently being evaluated. Forest, after drilling two vertical wells with production rates up to 1 MMCFD and three horizontals, is waiting for the rock work and the analysis before proceeding further. The horizontals rates range from 100 to 800 MCFD with 4 stage fracs. These are ten year leases. Forest estimated 4.1 TCF resource potential at 20% recovery. These black shales of 1 to 3% TOC are 500 ft thick within the gas window. Canbrian, Gastem, Junex, Questerre, Molopo, Intragaz, Petrolympic and Altai are among the other interest holders in this play.

Questerre Energy Corporation reported on the test results from the St. Edouard No. 1A horizontal well. The horizontal well was successfully completed with 8 stage fracture stimulations. Clean-up and flow back commenced January 29, 2010. During the test, the well flowed natural gas at an average rate of over 6 MMCFD.

http://www.questerre.com/assets/files/PDF/101121_QEC_Presentation-Update.pdf

Upper Ordovician Macasty Shale

In addition, the Upper Ordovician Macasty Shale (Utica Equivalent) drilled by Corridor and Petrolia on Anticosti Island in the Gulf of St. Lawrence has seen some interest, largely as a secondary target, with results from recent coring identifying shale oil potential. Corridor reported the results of an independent resource assessment of the Macasty Shale which resulted in a best estimate of the Total Petroleum Initially-In-Place 33.9 billion barrels of oil equivalent (BBOE) for Corridor's land holdings with the low estimate at 21.4 BBOE and the high estimate at 53.9 BBOE.

http://www.corridor.ca/investors/documents/March2011TechnicalPresentationonAnticostiIsland.pdf

http://www.corridor.ca/documents/Martel_Anticosti_NAPE_2012.pdf

http://www.corridor.ca/media/2011-press-releases/20110713.html

http://www.petroliagaz.com/imports/pdf/en/18168.Petrolia.FinalReport.pdf

Utica Emerges in Quebec Shale Play Extends to Canada by Susan Eaton

http://www.aapg.org/explorer/2010/01jan/shale0110.cfm

Quebec's natural gas royalty, which currently is 12.5%, has been described as attractive by some of the players. As well, shale gas plays in the province's St. Lawrence Lowlands enjoy another advantage in being close to the northeast U.S. gas market.

Quebec Shale Conference 2010 and 2009

The *Association pétrolière et gazière du Québec (*Quebec Oil and Gas Association)

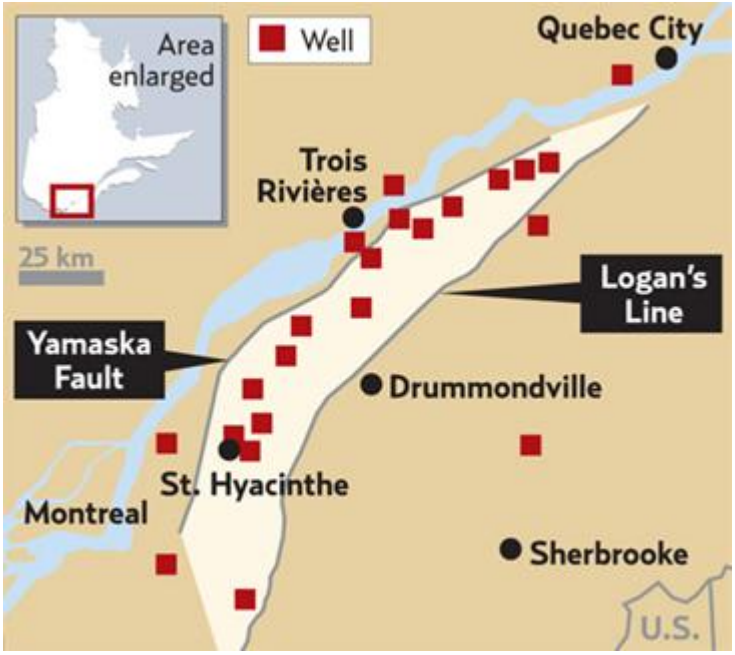
http://www.apgq-qoga.com/en/

http://www.apgq-qoga.com/en/2011/07/20/qoga-annual-conference/

Ministère des Resources naturelles et de la Faune de Québec is the regulator.

http://www.mrnf.gouv.qc.ca/english/energy/oil-gas/oil-gas-potential.jsp

Quebec Shale Gas Area



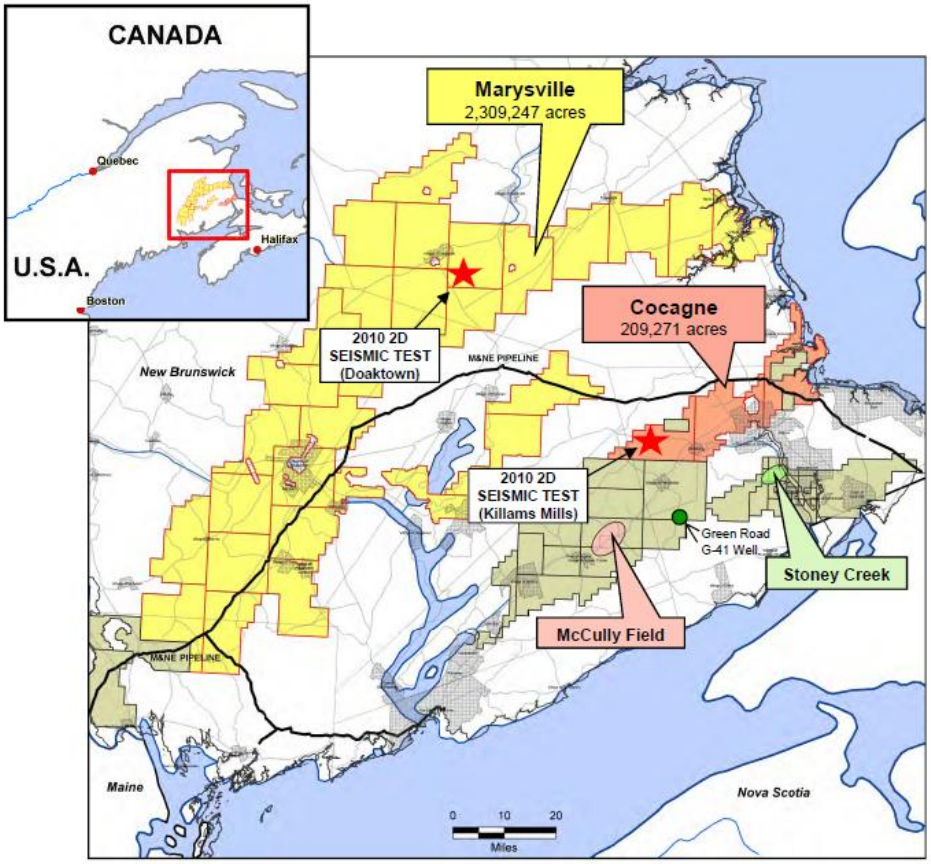
NEW BRUNSWICK

Lower Mississippian Fredrick Brook Shale
Moncton Basin

The Lower Mississippian Fredrick Brook Shale in the Moncton Basin has been the focus of thermogenic gas exploration in this province. The Green Road G-41 well was drilled by Corridor Resources in November, 2009 and tested in two zones in the Fredrick Brook, after fracing with propane. The lower black shale interval of the formation flowed at a rate of 0.43 MMCFD, whereas the upper silty/sandy shale zone of the formation tested at initial peak rates of 11.7 MMCFD with a final rate of 3.0 MMCFD. Corridor also announced the farmout of 116,018 acres this shale-potential land to Apache. Apache drilled their second well into this play and proceeded to run five slickwater stimulations per well with no gas recovery. Apache has left the project. Ten wells have been drilled into this play with seven completed and 6 testing gas. The rates have not been consistent. Another appraisal well has been recently spudded. Their plans are to try to develop this thick play of greater than 500 m vertically. During 2011 Corridor completed the drilling of the vertical Will DeMille O-59 shale gas appraisal well to a total depth of 3188 meters measured depth. Strong gas shows were encountered within Hiram Brook sandstones and the Upper Frederick Brook shale. Based upon initial analysis of well log information, the well intersected at least eight intervals with significantly elevated gas shows that are considered frac candidates. Corridor plans to evaluate these intervals with logs and sidewall cores in order to select the intervals for future fracture stimulation. The Will DeMille O-59 well is located north of Elgin, New Brunswick. Details of their play can be found at http://www.corridor.ca/documents/CorridorOverviewMemorandumFB.pdf

Contact Exploration and PetroWorth Resources are also re-evaluating their shale gas potential in the Fredrick Brook.

On March 16, 2010, Southwestern Energy Company bid $47 million for 2.5 million acres in two areas for both conventional and non conventional resources of the Mississippian Horton Group. The company has completed airborne magnetic and gravity acquisition and is in the second phase of surface geochemical sampling and the acquisition phase of approximately 250 miles of 2-D data. Interpretation of the data is underway. $10.7 million was invested in 2010 with $14.2 million investment planned for 2011and then $14.2 million in 2012 with possible well(s).



"Frederick Brook Shale spurs Canadian exploration," by Susan Eaton *AAPG Explorer*, August 2010, p.6-10.
http://www.aapg.org/explorer/2010/08aug/fredrick0810.cfm

New Brunswick Natural Resources, Minerals and Petroleum is the regulator for this province.
http://www.gnb.ca/0078/minerals/index-e.aspx
http://www.gnb.ca/0078/minerals/GSB_Hydrocarbon_Basin_Analysis-e.aspx#Objective
Shale Gas Website
http://www2.gnb.ca/content/gnb/en/corporate/promo/natural_gas_from_shale.html

Update on New Brunswick by Steven Hinds
http://www.wnloilandgas.com/media/uploads/Hinds_Nfld2011.pdf

NOVA SCOTIA

Upper Devonian/Lower Mississippian Horton Bluff
Kennetcook Basin

The Upper Devonian-Lower Mississippian Horton Bluff Shale in the Kennetcook Basin has been the primary target for thermogenic shale gas exploration in the province by Triangle (Elmworth) Petroleum since May 2007. A 2D and 3D seismic program was initiated and a total of 5 vertical exploration wells have been drilled since May 2007. Various fracture treatments have been performed although none have successfully produced gas so far. On April 16, 2009, Triangle executed a 10-year production lease on its Windsor Block in Nova Scotia which covers 474,625 gross acres (270,000 net acres) with a potential of 20 TCF recoverable. They have agreed to drill at least 7 more wells in this block before 2014. In 2009 they conducted a 30 km 2D seismic program to try to pinpoint areas with structure for future shale targets. Currently there has been no work this year as they are looking for partners.

The Government is appointing an internal committee of officials from the Departments of Energy and Environment to examine the environmental issues associated with hydraulic fracturing in shale gas formations and make recommendations on any additional required regulatory measures to be finished in early 2012. Given that there are currently no applications for hydraulic fracturing of shales in Nova Scotia and none are anticipated this year, it is a good time to complete this work.

This abstract is from "The Horton Bluff Formation Gas Shale Opportunity, Nova Scotia, Canada, Adam MacDonald, 2012 AAPG Search and Discovery
http://www.searchanddiscovery.com/abstracts/html/2011/annual/abstracts/MacDonald.html?q=%2BtitleStrip%3Acanada+%2ByearSort%3A%5B2011+TO+2012%5D

The Horton Bluff Formation gas shale's are within the Carboniferous lacustrine Horton Group of the Maritimes Basin. Gas in place (GIP) estimates are 69 TCF and leading indicators of a prospective shale gas play such as TOC at >5.5 % , Maturity (Ro) of 1.6, thickness of >500 meters and estimates of 100 Bcf per section across an area of > 2 million acres, have generated an increased interest in the Horton Bluff Formation within this frontier basin. Comparison of this shale play characteristics to many others (mineralogy, gas filled porosity, pressure gradient, adsorbed gas) across North America ranks the Horton Bluff shale as among some of the most prospective.

The Nova Scotia Department of Energy (NSDOE), working closely with industry, has recently undertaken the task of trying to understand the resource potential. GIP or "size of the prize" is determined by the shales' gas generating potential, the mineralogy which may dictate the fracing techniques and lead into the engineering solutions that need to be achieved through the drilling and piloting phase to reach commercial producabilty. Good seismic coverage (2-D and 3-D data) and well control is available to help define the shale's reservoir quality or "sweet-spots". Seismic interpretation linked to well data has given an understanding of the depositional system and structural evolution of the basin which then can be linked to predicted production variability. To date five wells have been drilled and two successful wells have shown volumes of gas to surface post completion and stimulation. The analogous shale reservoirs to the north (in New Brunswick) are currently in the evaluation pilot phase for scalable production by Apache Canada and attractive tight sands within the same formation are producing at approximately 25 mmcf/day through vertical wellbore at the McCully gas field.

The Nova Scotia Department of Energy is the regulator for the province.
http://www.gov.ns.ca/energy/oil-gas/onshore/

NEWFOUNDLAND

Ordovician Green Point Shale
Western Newfoundland

The Cambro-Ordovician Green Point Formation is the focus of exploration activity for oil bearing shale in the western parts of the province. This Green Point interval has been studied in outcrop by the Geological Survey of Canada and is summarized in Hamblin (2006). Oil seeps have been documented along the entire coastline. A well drilled in 2008 from the onshore to the near offshore by Shoal Point Energy and partners encountered about 500 m of shale with siltstone stringers with high gas and oil shows throughout the formation but no testing was attempted then. The geochemistry analysis indicates that this zone is in the oil window. Further drilling of the shale oil potential in this formation is underway by reentry of the previous well bore by the same companies in Jan 2011 with testing planned in Q2 2012. These companies have recently locked up contiguous blocks of land to the north stretching more than 160 km encompassing about 720,000 acres.

The Newfoundland Department of Natural Resources is the regulator for the onshore portion of the province. http://www.nr.gov.nl.ca/mines&en/oil/

http://www.nr.gov.nl.ca/nr/energy/petroleum/onshore/onshore.html

The Canada-Newfoundland Labrador Offshore Board is the regulator for the offshore portion. http://www.cnlopb.nl.ca/

TERRITORIES

NORTHWEST TERRITORIES

Devonian Canol Shale

The Northwest Territory Geoscience Office commissioned Dr. Brad Hayes of Petrel Robertson Consulting Ltd. of Calgary to undertake a regional-scale study of the unconventional shale gas and shale oil potential of the southern and central Northwest Territories. His report assembles available outcrop and subsurface data to systematically assess shale gas and oil potential and is available as NWT Open File 2011-08 (See below). The work follows on an earlier unconventional natural gas scoping study for the NWT also authored by Dr. Hayes (NWT Open File 2010-03)(See below).

Last summer Canada's Northern Oil & Gas Directorate held a lease sale in which all 11 Mackenzie Valley blocks offered were awarded for work commitment bids totaling more than C$530 million. It was speculated the Canol Shale play was the main target.

Currently Husky is drilling two vertical exploratory wells into the oil mature Devonian aged Canol and Hare Indian/ Bluefish Shales south of the community of Norman Wells in the Central Mackenzie Valley. Calgary-based MGM Energy has also announced plans for shale oil exploration, although it will not begin drilling until the 2012-2013 winter season. According to MGM, the Canol/Hare Indian shale is 30-170 metres thick at a depth of 1,000-2,500 metres. In addition, the Bluefish Shale is 15-25 metres thick at a depth of 1,000-2,700 metres. Both are highly brittle, which is a key attribute for successful fracturing. The Enbridge Norman Wells to Alberta pipeline runs through the area flowing 40,000 barrels of oil per day. The Norman Wells oil field discovered in the 1920s, has been in decline for decade and the pipeline is running at 33% capacity http://www.ihs.com/products/oil-gas-information/source-newsletter/international/jan2012/canadian-alaskan-exploration.aspx

Geoscience Office
http://www.nwtgeoscience.ca/petroleum/

http://www.nwtgeoscience.ca/petroleum/unconventional_gas.html

YUKON

Currently, the Yukon Geological Survey is conducting studies to determine the potential of shale gas in the territory. Shale gas has not been explored for or produced in Yukon; however, future oil and gas projects will most likely consider shale gas reservoirs as potential targets. Shale is likely found in all of Yukon's oil and gas basins. Whether or not the shale formations contain natural gas in sufficient quantity to produce has yet to be determined. The Yukon Geological Survey is currently conducting a scoping study to identify the presence of shale gas and other unconventional oil and gas resources in the Yukon. The results of this study are expected in the spring of 2012 and will be published on both the Yukon Geological Survey and Oil and Gas Resources websites.

Yukon Energy, Mines and Resources
http://www.geology.gov.yk.ca/
http://www.emr.gov.yk.ca/oilandgas/

NUNAVUT

There are 12 Basins with potential and discovered hydrocarbons through to the Paleozoic. Nothing is being worked on but shale plays would exist within the many source rock intervals. It is too isolated to be commercial at present.

Canada-Nunavut Geoscience Office
http://cngo.ca/

Societies, Conferences and Courses

Canadian Society for Unconventional Gas (CSUR)
http://www.csur.com/

Presentations and Publications
http://www.csur.com/index.php?option=com_content&view=article&id=71&Itemid=117

14th Annual Unconventional Resources Conference
October 3 & 4, 2012 Calgary TELUS Convention Centre
120 - 9th Avenue SE, Calgary
https://event-wizard.com/14UGCIntro/0/pages/48310/

Canadian Society of Petroleum Geologists (CSPG)
http://www.cspg.org/

GeoConvention 2012: Vision, Calgary, TELUS Convention Centre May 14 – 18, 2012
And Core Conference May 17th and 18th at the ERCB Core Research Centre in Calgary.
http://www.geoconvention.com/

Other Meetings

CI Energy Group's Shale Gas & Oil Symposium Jan 24 and 25 2012 Hyatt Regency Hotel Calgary Alberta

http://www.shalegassymposium.com/

Tight Oil Canada 2012 February 28-29, 2012 Calgary, Canada
http://www.tight-oil-canada-2012.com/

Reserve Estimations For Tight Oil & Shale Gas, Canada 2012
March 27 - 28, 2012 Calgary Telus Convention Centre
http://www.reserve-estimations-canada.com/

Unconventional Gas Technical Forum – Victoria, B.C.
The Ministry of Energy and Mines, in collaboration with the B.C. Oil and Gas Commission, is proud to host the 6th B.C. Unconventional Gas Technical Forum on April 2–3, 2012 at the Victoria Conference Centre
http://www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/UnconventionalGas/Pages/default.aspx

CI Energy Group's Tight Oil
How to Capitalize on Technological Advances and Market Changes
Wednesday, April 25 to Thursday, April 26, 2012
Calgary Marriott Downtown, Calgary, Alberta http://www.canadianinstitute.com/2012/365/tight-oil

2012 Williston Basin Petroleum Conference & Expo May 22-24, 2012
Bismarck Civic Center, 315 South 5th Street
Bismarck, North Dakota, 58504
https://www.wbpcnd.org/

Hart Energy's Developing Unconventionals (DUG™) Canada conference and exhibition, June 18-20, at the TELUS Convention Centre, in Calgary, Alberta, Canada. The event is presented jointly with the Canadian Society for Unconventional Resources.
http://www.dugcanada.com/

Exploration, Mining and Petroleum
New Brunswick 2012, November 4-7, Fredericton, New Brunswick - Delta Hotel
http://www.gnb.ca/0078/minerals/Exmin_Home-e.aspx

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Carter, Fortner and Béland-Otis; Ordovician and Devonian Black Shales and Shale Gas in Southwestern Ontario, Canada, 2009
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Shale Gas and Shale Liquids Plays in Europe

By Ken Chew

Summary of past six months

In Europe, the six months from October 2011 to March 2012 have seen more action in the political / environmental sphere than in exploration activity. Apart from a shallow biogenic shale gas program in central Sweden and a combination coal seam gas / shale gas exploration well in England, the only new drilling took place in Poland, where at least 11 shale gas exploration wells were spudded.

Opposition to shale gas exploration and hydraulic fracturing has spread to Austria, the Czech Republic, Northern Ireland and Romania, while Bulgaria has introduced a ban on fracing which resulted in the cancellation of a licence award to Chevron which was due to take place,

Shale gas in Europe

Europe is particularly well-suited to gas resource play exploitation on account of its large market, established pipeline infrastructure, increasing demand and current dependence on gas imports. Relatively high natural gas prices add to the attraction.

Shale gas exploration in Europe is in its infancy. The first exploratory well was spudded in Germany in 2008 and since then shale-specific exploratory drilling has been limited to five countries. As a consequence, little is known about Europe's ultimate potential.

Rogner's 1996 estimate of the in-place shale gas resource of Europe (including Turkey) was 550 Tcf. More recent studies indicate significantly larger in-place resources. In their assessment of the world's shale gas resource, the U.S. Energy Information Administration (EIA) estimated the European shale gas in-place resource for 10 countries (excluding Ukraine) at 2,390 Tcf with a combined technically recoverable resource of 582 Tcf (U.S. EIA, 2011).

Nevertheless, these estimates must be treated with caution. Much of the detailed information required to make accurate assessments is simply not available in many areas and so the assessments are still relatively speculative. To give two examples which indicate the caution that must be exercised when using the data, the EIA report provides an estimated technically recoverable resource of 41 Tcf for Sweden's Alum Shale, which Shell's recent three wells found to have very limited content of natural gas which it was not possible to produce. Another noteworthy example is in Poland where the EIA report estimated the risked technically recoverable resource at 187 Tcf while a study published in March 2012 by the Polish Geological Survey, in conjunction with the USGS, placed estimated recoverable resources in the range 12 – 27 Tcf.

By way of contrast, the Midland Valley of Scotland, where Europe's first certification of recoverable shale gas resources has taken place, is considered by the EIA report to be non-prospective.

OMV has suggested a potential recoverable shale gas resource of 15 Tcf in the Vienna Basin, Austria, from an in-place resource of 200-300 Tcf. TNO's "best estimate" for "producible gas in place" in "high potential" areas of the Netherlands is 198 Tcf from an estimated in-place resource of 3,950 Tcf.

Given the potential size of the in-place resource it is not surprising that investigations have been proposed in at least sixteen countries. Company interest extends from super-majors, such as ExxonMobil and Shell, through majors (Chevron; ConocoPhillips; Eni; Total) and major independents (e.g. Marathon; Talisman) to small niche players (e.g. Cuadrilla Resources) and coal seam gas explorers who may have some shale gas potential on their acreage (e.g. IGas Energy).

Major shale gas plays in Europe

There are three potentially major regional shale gas plays in Europe plus a number of others with local potential.

Lower Paleozoic

The oldest is a Lower Paleozoic play that occurs in northwest Europe running from eastern Denmark through southern Sweden to north and east Poland. The organic-rich shales with shale gas potential lie on the south western margin of the Baltica paleocontinent and tend to thicken towards the bounding Trans-European Suture Zone.

A second Lower Paleozoic play occurs on the composite Saxothuringian-Barrandian-Moldanubian terranes (Bohemia) that probably detached from Gondwana at around the time of the Ordovician-Silurian boundary.

Czech Republic

BasGas (now Hutton Energy) has applied for acreage in the Prague and Intra-Sudetic basins of the composite Bohemian terranes. The Trutnov application in the Intra-Sudetic Basin was approved on 21st December 2011. The Silurian pelagic shale is reported to be the target in both basins.

The remaining Lower Paleozoic plays occur on or adjacent to the Baltica terrane. In Denmark and Sweden the principal target is the kerogenous Alum Shale of Middle Cambrian to Early Ordovician (Tremadoc) age.

Denmark

Licences have been awarded over the Fennoscandian Border Zone and Norwegian-Danish Basin onshore Denmark. Total has been awarded two licences and in March 2012 applied for a third area

relinquished by Schuepbach Energy in November 2011. Total and the Danish North Sea Fund (Nordsøfonden) plan to commence exploration of the Alum Shale in the Jutland area (Fennoscandian Border Zone) during 2012.

Sweden

On 28th November 2009 Shell spudded the first well in a three-well test program in Sweden's Colonussänkan permit (Fennoscandian Border Zone, southern Sweden). Lövestad A3-1, Oderup C4-1 and Hedeberga B2-1 ranged in depth from 2,457' to 3,133'. In May 2011, Shell announced that its investigations had been completed, that the rock samples from the three wells found only very limited gas traces which are not producible, and that the licences would not be renewed when they expire at end-May 2011 (Svenska Shell 2011).

In October 2012, Aura Energy, an Australian uranium exploration company that is investigating the uranium potential of Sweden's Alum Shale, commenced a three to five hole drilling programme at its Motala shale gas project in Östergötland, south-central Sweden, on the east shore of Lake Vättern near the town of Linköping. The Alum Shale at this location occurs at shallow depth and is thermally immature but with high TOC contents of up to 20%. It is therefore considered to be an analogue to the biogenic-sourced shale gas of the Antrim Shale in the Michigan Basin. Gas flows are known from water wells and seeps in the area and flow rates of up to 40,000 cf/d have been reported from wells. Local farmers use the gas as a heating source and the Linköping commune has a processing concession, valid until 2033. In total, four companies own 19 concessions in the Östergötland Lower Paleozoic Basin. Further north, AB Igrene has 19 concessions with Alum Shale potential in the Siljan Ring, where Lower Paleozoic rocks have been preserved around the margin of a depression formed by a major Late Devonian meteor impact. Gripen Gas also has five (5) concessions in the Baltic Depression on the island of Öland.

Poland

Further to the southeast, in Poland, the main Lower Paleozoic target is Silurian-age graptolitic shale, with the Upper Cambrian to Upper Ordovician a secondary target. The Silurian in particular thickens towards the southwest in the area of the Gdansk Depression (Baltic Depression) and the Danish-Polish Marginal Trough which defines the southwest margin of the Baltic Depression. In parts of the Trough, such as the Warsaw Trough and Lublin Trough, more than 10,000' of Silurian section may be present.

To date, this play has been the most sought after in Europe. Some 35 concessions have been awarded in the Baltic Depression, of which 7, operated by LOTOS Petrobaltic, are offshore in the Baltic Sea and 28 lie onshore in the Gdansk Depression. Some of the most easterly concessions, such as the four held by Silurian Energy Services, are considered to be more prospective for shale liquids than for shale gas. Another 39 concessions have been awarded in the Danish-Polish Marginal Trough and 15 on the East European Platform Margin, northeast of the Marginal Trough.

Twelve different companies are active in the onshore Gdansk Depression including a number of small niche players, but of the 54 concessions on the Platform Margin and Marginal Trough, 21 are operated by one of ExxonMobil, Chevron or Marathon and a further 16 by PGNiG, the Polish state company, or PKN Orlen, another Polish company.

Baltic Depression

The first tests of the Polish Lower Paleozoic commenced in the Gdansk Depression of the Baltic Depression. Between June and October 2010, Lane Energy (a subsidiary of 3Legs Resources) drilled two vertical wells, Lebien LE-1 (Lębork concession) and Legowo LE-1 (Cedry Wielkie concession). A 3,300' horizontal leg drilled in a second Lebien well (LE-2H) in May 2011 was the first horizontal shale gas well drilled in Poland. After a 13-stage hydraulic frac the well flowed an unstabilised 2.2 mmscf/d on 8th September 2011 using coiled tubing and N_2 lift. It was recompleted with a tubing string on 17th September and flowed from 380 up to 520 mscf/d on N_2 lift, plus frac fluid. 15% of the total frac fluid had been recovered by the end of the test. The productive intervals in all three wells were in the Lower Silurian and Upper Ordovician.

In July 2011 Lane spudded Warblino LE-1H, in a third concession (Damnica). A vertical pilot was drilled to 10,570'. This was followed by a horizontal leg of 4,088' within the top 16' of a new deeper prospective interval (Lower Ordovician?; Cambrian?), then redrilled with a 1,650' horizontal leg (12,610' MD) because of hole stability issues. A 7-stage hydraulic frac test was suspended after 5 days during which flow declined from 60-90 mscfd to 18 mscfd. Lane's initial seismic and drilling program on its six Gdansk Depression concessions is being funded by ConocoPhillips (see *4.3 Ownership Transactions: Farm-ins*). The companies plan one vertical well on the Lębork concession in the second half of 2012.

The drilling contractor, NAFTA Pila, which drilled the first two Lane wells spudded Wytowno S-1 (Slawno concession) in December 2010 on behalf of Saponis (BNK; RAG; Sorgenia: LNG Energy). The US$ 6 million well reached TD at 11,745' in mid-February 2011. The well encountered gas shows in a shallower 130' Lower Silurian section and over a deeper 300' Lower Silurian hot shale section. The well appears to have been drilled on a localised paleo-topographic high which accounts for the absence of a Cambro-Ordovician section. The strongest shows were recorded in the deeper Lower Silurian interval (124 scf/ton), while the shallower interval averaged 77 scf/ton. Wytowno S-1 was followed by a 11,780' well, Lebork S-1, on the Slupsk concession which encountered gas shows over a 935' interval from Lower Silurian to Cambrian Alum Shale. The Lower Silurian averaged 40 scf/ton while the 155' Cambro-Ordovician interval averaged 268 scf/ton. Total Organic Carbon is also significantly higher in the Cambro-Ordovician interval.

In July 2011 Saponis spudded a third well, Starogard S-1 which had reached a TD of 11,560' by early September. The well encountered a similar Lower Silurian to Cambrian section to that of Lebork S-1 with a gross thickness of some 820'. Gas contents (Lower Silurian: 38 scf/ton; Ordovician: 17 scf/ton) were lower than in the first two wells. Completion of the first two wells commenced in mid-September 2011 with fracing of the Cambrian interval in Lebork S-1 commencing on 30th September. The fracturing of the Cambrian and Ordovician intervals did not permit an effective test to take place as insufficient proppant was injected as a result of higher than expected overpressures. The gas that did flow and was flared contained methane, ethane and propane. The fracture test has now been rescheduled for spring 2012 at which time weather conditions should be suitable and a high pressure stimulation string will be available. Testing of Wytowno S-1 and Starogard S-1 has also been postponed till this time

BNK announced that it would commence the drilling of three wells on its wholly-owned blocks to the south of the Saponis Slawno and Slupsk concessions in February 2012 and on 28th February spudded Miszewo T-1 in the Trzebielino concession.

San Leon / Talisman commenced a two vertical well Gdansk Depression drilling program with the spudding of the Lewino 1G2 well in the Gdansk-W concession in late September 2011. Strong gas shows were encountered over an interval in excess of 3,300' ranging from Middle Silurian to Upper Cambrian. After reaching a TD of 11,810' the rig moved to the Rogity-1 location on the Braniewo concession. This well drilled to 9,147', encountering shows of rich gas over a 1,600' interval from Lower Silurian to Middle Cambrian. Oil shows were also recorded in Lower Silurian shale, Ordovician limestone and shale and Middle Cambrian sandstone.

A promising gas flow was also reported by PGNiG from a frac test of the Silurian and Ordovician on its Lubocino-1 well on the Wejherowo concession, completed in March 2011. Gas quality was good with heavier hydrocarbons reported, no H_2S and low N_2. A second, horizontal, well is planned for this location. The company has indicated that it may start production from the area in 2014.

Eni is also understood to have commenced an initial 3-well program planned for its Gdansk Depression acreage. Total commitments are 6 wells.

An interesting feature revealed by sampling and gas shows from the three Lane Energy, three Saponis and two San Leon / Talisman well locations is that thermal maturity appears to decrease in an east to northeast direction leading to an increase in the content of NGLs. The Starogard well produced hydrocarbons up to pentane and Rogity 1 produced C1 – nC8 while the western wells in general produced only methane, ethane and propane. This does suggest that there is the potential for significant liquids production from some concessions.

Danish-Polish Marginal Trough & East European Platform Margin

The first wells in the Podlasie Depression of the East European Platform Margin (Siennica-1) and Lublin Trough of the Danish-Polish Marginal Trough (Krupe-1), were drilled by ExxonMobil in Q4-2010 and Q1-2011. The wells were fracced in September / October 2011 but the wells failed to flow commercial volumes of gas.

Despite the disappointing results from the ExxonMobil wells, the East European Platform Margin and Danish-Polish Marginal Trough are very much the focus of current drilling activity, with at least 8 wells spudded in the past six months.

On 24th October 2011 PKN Orlen commenced its drilling program in the Lublin Trough of the Danish-Polish Marginal Trough spudding its first well at Syczn (Wierzbica concession). This was followed by a second well spudded in mid-December at Berejow (Lubartów concession).

Chevron also commenced its Lublin Trough program in Q4-2011 with a well in the Grabowiec concession at Lesniowice, spudded on 31st October. A second well at Andrzejow on the Frampol concession was spudded in March 2012.

In Q4-2011 and Q1-2012 Marathon drilled two wells on the East European Platform Margin, Cycow-1 (Orzechow concession) and Domanice-1 (Siedlce concession). Drilling activity has now moved to the Danish-Polish Marginal Trough where Lutocin-1 (Rypin concession) will spud in early April to be followed by three other wells in 2012, all four located in the Pommeranian and Warsaw troughs.

San Leon / Talisman spudded Szymkowo-1, the final well in their 3-well drilling program, on the Szczawno concession, Danish-Polish Marginal Trough (Pomeranian Trough), in early March 2012.

PGNiG spudded the Lubycza Królewska-1 well on the Tomaszów Lubelski concession, Lublin Trough on 26th March 2012.

It has been reported that ExxonMobil plans to drill six (6) wells between Q3-2012 and Q3-2013.

The Polish Treasury Ministry is said to be targeting commercial production from at least one pad by late 2014 or early 2015. It is assumed that the initial production of 20 – 30 million cf/d will come from the Lower Paleozoic play. PGNiG has indicated that it would like to provide local supply from its Lubocino well in the second half of 2012.

Lithuania

The Cambrian to Lower Silurian succession is also thought to have potential in south-west Lithuania. Local oil producer Minijos Nafta has indicated that it intends to drill an exploration well on its existing

acreage in 2012 to test the Ordovician and Silurian. It may also frac an existing well prior to drilling the exploration well. Polish Group Lotos SA, which owns Lotos Geonafta, also plans to drill in 2012.

The Lithuanian Geological Survey plans to open two areas to tender for exploration in spring 2012. Applicants will have four months in which to submit bids with awards expected by end-year. The larger area (Silute-Taurage – 540 sq mi) will require experience in shale gas exploration.

Romania

Chevron has acquired a concession (Barlad) on the platform margin in northeast Romania where the Silurian foredeep shales that are prospective in Poland and Ukraine are also believed to occur. The first well in a multi-well drilling program is planned for late 2012.

Carboniferous

The second major play is a Carboniferous basinal marine shale play that extends eastwards from western Ireland and includes the East Irish Sea / Cheshire Basin in northwest England, the Anglo-Dutch Basin, the Northwest German Basin, the Fore-Sudetic Monocline (Northeast German-Polish Basin) in southwest Poland, and the Culm Basin in eastern Czech Republic. The age of the most prospective shales appears to young westwards from the Visean (Middle Mississippian) Kulm facies of Poland, the Czech Republic and northeast Germany to the Namurian (Upper Mississippian to Lower Pennsylvanian) of northwest Germany, the Epen Formation of the Netherlands, the Bowland Shale in northwest England and the Clare Shale in western Ireland. Visean (Middle Mississippian) shale may also be prospective in Scotland and northwest Ireland.

Czech Republic

Cuadrilla Resources has received preliminary notification of the award of the Mezerici licence in which the target is considered to be deep marine sediments present in the Lower Carboniferous of the Culm Basin, where the Variscan foreland basin reaches its most easterly extent on the eastern flank of the Bohemian Massif.

Germany

The nature of German E&P reporting is such that it can be difficult to establish the activity taking place on long-held licences. It is assumed that ExxonMobil, both directly and indirectly through the BEB ExxonMobil / Shell joint venture, will be examining the potential of Visean (Middle Mississippian) shale in eastern Germany and Namurian (Upper Mississippian to Lower Pennsylvanian) shale in the west. Some at least of BNK Petroleum's six concessions are also targeting Carboniferous shale gas, as are Winterhall's Rhineland and Ruhr permits.

Ireland (Republic of Ireland & Northern Ireland)

Enegi Oil has taken out option ON11/1 to evaluate the shale gas potential of the Namurian (Upper Mississippian – Lower Pennsylvanian) Clare Shale in western Ireland. The Clare Shale is known to have high levels of thermal maturity so the issue here may be whether it is over-mature for gas. In the Northwest Ireland Carboniferous Basin (Lough Allen Basin), which straddles the border between the Irish Republic

and Northern Ireland, Tamboran Resources and the Lough Allen Natural Gas Co. have taken out licences on both sides of the border to evaluate the potential of the Visean (Middle Mississippian) Bundoran and Benbulben shales, both of which yielded strong gas shows in wells drilled in the mid-1980s.

Netherlands

Cuadrilla Resources has been awarded a license (Noord Brabant) on the margin of the London-Brabant High and West Netherlands Sub-basin of the Anglo-Dutch Basin. It is assumed that the Namurian (Upper Mississippian to Lower Pennsylvanian) Geverik Member of the Epen Formation shale is one of the targets in this location. Two wells, at Boxtel and Haaren, are planned. Drilling of the first well is now planned for 2013 as a result of additional drilling planned on Cuadrilla's UK Bowland Shale acreage (below) and permitting delays. It is also possible that one of these wells may be targeting shale oil in the Lower Jurassic Aalburg and Posidonia formations in the Roer Valley Graben while another also targets tight gas in the Triassic. Cuadrilla's other Netherlands licence (Noordoostpolder) in the Northwest German Basin is a Namurian gas shale play.

Poland

Lane Energy, the 3Legs Resources subsidiary, has interests in the Fore-Sudetic Monocline in southwest Poland but unlike the Gdansk area, this activity is not funded by ConocoPhillips. San Leon has also acquired some concessions covering this play, as have PKN Orlen, Silurian Energy Services, Strzelecki Energia (Hutton Energy) and Eco Energy. Although all of these 16 concessions are considered to have some shale gas prospectivity, some are also being investigated for their conventional oil and gas prospects. On behalf of the Polish state company, PGNiG, Halliburton frac tested Upper Carboniferous shale in Markowola-1 in the Lublin Trough in July 2010 but the flow rates are said to have been lower than expected.

The next test of the Carboniferous, Siciny-2, was spudded on 10th November 2011 by San Leon in the Gora concession. This well was located close to Siciny 1G-1, drilled in the 1970s, which had encountered a 3,266' Carboniferous section and was still in Carboniferous at TD. Siciny-2 was drilled to a depth of 11,550', encountering some 3,300' of Carboniferous. Continuous gas shows were encountered across four prospective shale intervals and a fractured tight sandstone interval encountered below 10,500'.

United Kingdom
England

Cuadrilla Resources, through its Bowland Resources subsidiary, has interests in the onshore portion of the East Irish Sea Basin in PEDL 165 in Lancashire, northwest England. Spudded on 16th August 2010, the company's Preese Hall-1 well targeted a Visean-Namurian (Middle Mississippian to Lower Pennsylvanian) interval with the Bowland Shale the primary target. Drilled to a depth of 9,098', the vertical well encountered over 4,000' of shale between 4,400' and 9,004'. The shales contained both vertical and horizontal fractures and produced "substantial gas flows". The well encountered three prospective shale formations with a net thickness of 2,411': Sabden Shale of Arnsbergian (Late Mississippian) age (approximately 170'); Bowland Shale of Brigantian (Middle to Late Mississippian) age (1,685'); Hodder Mudstone of Visean (Middle Mississippian) age (554'). Preese Hall-l was the first known test of the Carboniferous shale gas play in Europe.

The well was due to have a 12 frac-stage completion over an interval from 5,260' to 9,000' but after 5 fracs, fracing was suspended due to two small earthquakes in the vicinity of the well (2.3 and 1.5 Richter Local Magnitude). The company commissioned a study to determine the relationship, if any, between the fluid injection and seismicity (see *5. Above-ground issues: United Kingdom*). The first three fracs (perforated intervals from 8,420' – 8,949' in the Hodder Mudstone) were tested on comingled flow and produced satisfactory amounts of gas and frac flow-back water. Fracs 4 and 5 (7,810' – 8,259' in the base of the Lower Bowland Shale) were being flowed in mid August 2011.

Between January and August 2011 the rig drilled a second well 3 km NE of Preese Hall-1 at Grange Hill-1, where top Lower Bowland Shale was forecast at ~ 6,500', slightly shallower than in Preese Hall-1. Preliminary core analyses suggest similar gas contents to Preese Hall-1 but over a thicker series of possible pay zones, as indicated by the final TD of 10,775' compared with the forecast TD of 9,500'. The rig then moved to a third location in the area, which represented a substantial step-out from the locations of the first two wells. Becconsall-1, 15 km south of Preese Hall-1, spudded on 16th August 2011. Top Lower Bowland Shale was forecast at ~ 8,000', significantly deeper than in the previous two wells. On 13th October a vertical sidetrack, 1Z, was spudded and the well was completed on 21st December 2011. No results have been announced other than the TD of 10,500'. Drilling will commence shortly on a fourth well (Anna's Road-1), some 5 km southwest of the Preese Hall-1 location.

Based on gas desorption and geochemical studies undertaken at the Preese Hall well and a net shale thickness of 2,411' in that well, original gas in place at the Preese Hall location was estimated at 538.6 Bcf / square mile. On 22nd September 2011, Cuadrilla Resources announced a preliminary gas in place estimate of 200 Tcf for its 1,130 km^2 (436 square miles) PEDL 165 licence in Lancashire. The uncertified estimate is based on the two wells drilled to date by Cuadrilla plus historical data from three wells drilled between 1987 and 1990 by British Gas.

On 4th November 2011, IGas Energy spudded a joint coal seam gas / shale gas exploration well on PEDL 190 south of the River Mersey opposite Liverpool, in the Cheshire Basin. The well was completed on 21st January 2012 having encountered about 1,000' of Bowland Shale in which gas indications were observed throughout. The well was still in shale at TD. Previous independent analysis suggested 4.6 Tcf gas in place in this area.

The Bowland Shale may also be prospective east of the Pennine High in the East Midlands Sub-basin, where it is a known source rock for oil and gas. In Q4-2012, eCorp is scheduled to drill one vertical well in the Gainsborough Trough area to test the Bowland Shale and to a depth of 14,750', or to sufficient depth to test the Dinantian shale. Dart Energy has bought into this acreage through its acquisition of Greenpark Energy's unconventional gas assets (see *4.2 Licence Acquisitions: United Kingdom*).

On PEDL 252 on the southern margin of the Wales – Brabant High near Woodnesborough in Kent (north of the Kent Coalfield), Coastal Oil & Gas has received planning permission for a well to take core samples of some 8 Westphalian (Middle Pennsylvanian) coal seams and the Lower Limestone Shales of the Tournasian (Lower Mississippian) Avon Group. It is not known when this well will be drilled.

Wales

IGas Energy has identified 1.14 Tcf of 2P contingent resources of gas in place in the Bowland Shale equivalent on its acreage in North Wales.

In South Wales Coastal Oil & Gas applied for permission to drill the Llandow gas shale exploration well to a depth of 2,130' to log and core the Namurian Millstone Grit Shale Group, the Dinantian Upper Limestone Series and Lower Limestone Series, and possible gas shale in the Ordovician, in addition to Devonian tight gas. Despite this well being drilled on the same basis as previous coal seam gas exploration

wells drilled in the area by Coastal in 2007/8, the company was obliged to withdraw the application in the face of local opposition to the drilling. When resubmitted the application was rejected by Vale of Glamorgan Council (see *5. Above-ground issues: United Kingdom*). Although the principal shale gas target in the Llandow well appears to have been the Lower Limestone Shales of the Courceyan (Lower Mississippian) Avon Group, Coastal's partner, Eden Energy has identified the Namurian as the principal target over its acreage. The most prospective unit is presumed to be the Pendleian (basal Namurian or Upper Mississippian) Aberkenfig Formation. Eden has reported a gross unrisked P90 estimate of 34.2 Tcf shale gas in place in the Namurian of its seven South Wales licences.

In August / September 2011, U.K. Methane (a company with similar management to Coastal Oil & Gas) spudded St Johns-1 and Banwen-1, targeting Namurian shale. The target depths are believed to be relatively shallow, about 2,000' in the case of St Johns-1.

Scotland

In June 2011, Australia's Dart Energy (formerly Composite Energy) announced the results of an independent assessment of shale resources in PEDL 133 in the Midland Valley of Scotland by Netherlands Sewell & Associates. This indicates an estimated gas-in-place of 0.8 Tcf in the Namurian (Upper Mississippian to Lower Pennsylvanian) Black Metals Member (Limestone Coal Formation) of the Kincardine Basin at depths of 1,000' to 4,000', and with a potential resource of 0.1 Tcf. The deeper Visean (Middle Mississippian) shales of the Lawmuir and Lower Limestone formations are estimated to contain 3.6 Tcf gas in place with a gross resource of 0.5 Tcf. Dart Energy owns 100% of the Namurian prospect but BG has a 51% interest in the Visean prospect. Dart and BG plan a shale gas exploration well in 2012.

Liassic (Lower Jurassic)

The third major regional play comprises Lower Jurassic bituminous shales that are being targeted in the Weald Basin (southern England), Paris Basin, the Netherlands, northern Germany and Switzerland's Molasse Basin. In continental Europe, the principal target is the Lower Toarcian Posidonia Shale. In eastern Germany and Poland the Lower Toarcian grades into a terrestrial facies and loses its source potential. In southern England the principal bituminous shales are older and occur in the Lower Lias.

These bituminous shales are clearly oil-prone. The principal limitation regarding their shale gas potential therefore lies in finding locations in which they have been sufficiently deeply buried to have entered the gas window. Locations where this may have occurred include the flexural foreland basin of the Swiss Molasse and the Mesozoic depocentres of the Lower Saxony Sub-basin (Northwest German Basin) and the offshore Broad Fourteens Basin and Central Graben of the Netherlands.

A number of companies are thought to be investigating Lower Jurassic shale gas potential. These include Cuadrilla Resources in *England*'s Weald Basin and Schuepbach Energy in *Switzerland*'s Molasse Basin. Whether the Liassic shales will be within the gas window in the Weald Basin remains to be seen though it is possible that they may have generated biogenic gas at shallow depths.

Germany

The ExxonMobil / Shell co-venture (BEB) commenced shale gas exploratory drilling in 2008 in the Lower Saxony Basin, drilling Damme-2/2A and 3 in the Munsterland concession and Oppenwehe-1 in Minden. Schlahe-1 was drilled in 2009 and Niedernwöhren-1 was spudded in the Schaumburg permit in October 2009. Damme-3 is known to have been frac tested (3 fracs). Posidonia Shale is presumed to have been at least one of the targets for these wells. ExxonMobil is believed to have spudded Lünne-1

(Bramschen concession, Emsland) around 17th January 2011 and reached the Posidonia Shale at about 4,720'. The well is planned to have a 1,600' horizontal leg. In March 2011 Lünne-1A (the horizontal leg) was drilling. BNK Petroleum (six concessions) and Realm Energy, a wholly-owned subsidiary of San Leon (one concession) have also announced the Posidonia Shale as a target.

Other plays with shale gas potential

Austria

OMV is investigating the potential of the Upper Jurassic Mikulov Formation in the Deep Vienna Basin. The company estimates that the formation contains 200 – 300 Tcf of gas in place of which 15 Tcf may be recoverable. The target occurs at depths greater than 14,700' and a temperature of 160° C. Two initial wells are planned near Poysdorf in the Mistelbach District of Lower Austria.

Bulgaria

The Lower to Middle Jurassic of the Moesian Platform, especially the basal Stefanetz Member of the Middle Jurassic Etropole Formation, is a target in northern Bulgaria, where both Direct Petroleum (TransAtlantic Petroleum) and Chevron now have licences. Direct Petroleum / LNG Energy spudded the 10,500' Goljamo Peshtene R-11 well in the A-Lovech exploration licence in late September 2011. The well (TD 10,465') encountered 375' of net pay in the Etropole Formation with numerous gas shows in the C1 – C3 range. TransAtlantic has estimated the gross unrisked prospective undiscovered recoverable resource at 11 Tcf (best estimate).

Croatia

Hungary's MOL and its part-owned subsidiary INA have indicated that the Miocene of the Mura and Drava sub-basins (Pannonian Basin) of eastern Croatia has shale gas potential.

France

Permo-Carboniferous basins in the Languedoc such as the Stephanian-Autunian (Upper Pennsylvanian – Lower Permian) Lodève Basin may have some potential in bituminous Autunian (Lower Permian) shale. Schuepbach Energy was awarded two permits in the Landguedoc-Provence Basin, one of which also incorporated part of the Lodève Basin. Total was awarded the Montélimar permit. The Schuepbach and Total permits have since been cancelled (see *5. Above-ground issues: France*). A number of other companies have also applied for permits in Languedoc-Provence, many of them overlapping. Realm (San Leon) has identified Stephanian-Autunian potential in the Bresse-Valence Basin, where it has submitted an application. Elixir Petroleum is exploring for shale gas (and tight gas) in the Permo-Carboniferous of the Moselle concession in the eastern Paris Basin, where in the past at least two wells have produced gas to the surface from the target interval (probably Carboniferous). In the main Paris Basin many conflicting applications have been filed. While the main focus of these is probably Liassic shale oil, a number are presumably also targeting shale gas potential in underlying Permo-Carboniferous half-grabens.

Germany

The Upper Devonian Kellwasser shale has been touted as having potential in northern Germany, as have Wealden paper shales of Berriasian age in the Lower Saxony Sub-basin, where ExxonMobil / Shell encountered 2,000' of Wealden sediment in Oppenwehe-1 in 2008. Realm Energy (San Leon) also sees the Wealden as a potential target on its Aschen concession. In the Bodensee Trough, north of the Swiss-

German border, Parkyn Energy, another 3Legs Resources subsidiary, has taken out two licences in which the principal prospect appears to be lacustrine shale of Permian age.

Hungary

The shale gas exploration situation in Hungary is unclear. In September / October 2009, Falcon Oil & Gas / ExxonMobil / MOL tested an Upper Miocene basin-centred gas prospect in the Makó Trough (Pannonian Basin) with only limited success, after which ExxonMobil and MOL exited the project. But Falcon has suggested that its acreage holds a "potential fractured oil and gas play". MOL and its part-owned subsidiary INA have indicated that the Miocene of the Mura and Drava sub-basins (Pannonian Basin) of eastern Croatia has shale gas potential and it can be assumed that this extends into western Hungary.

In September 2009, Austria's RAG (Rohöl-Aufsuchungs Aktiengesellschaft) acquired Toreador Hungary Ltd. Toreador had just drilled the Balotaszallas-E-1 (Ba-E-1) well in the Kiskunhalas Trough of the Pannonian Basin. Ba-E-1 encountered an over-pressured 1,840' gross gas-bearing interval in an interbedded Karpatian (Lower Miocene) sequence of siltstone, shale and sandstone below 10,000'. The two lowest zones were fractured and are believed to have produced gas-condensate. At that time, the tested lithology was reported as tight sandstone (Shaoul et al., 2011).

In July 2011, the Delcuadra Kft consortium (Delta Hydrocarbons 53%; RAG 25%; Cuadrilla 22%) recompleted an additional 3 zones of the Lower Miocene reservoir in Ba-E-1. At the Global Shale Gas Plays Forum in September 2011, RAG reported this as a shale gas frac and has subsequently confirmed that the completions were carried out in "a thick heterolithic sequence of shales and (very) fine clastics". Testing produced a gas flow rate of 1 million cfg/d plus small amounts of condensate. Both are being sold and a long term production test commenced in August 2011 and full gas-condensate production should commence before end-2011. Cuadrilla has the option to earn a further interest by drilling and completing a second well in the Ba-IX Mining Block. This well, Ba-E-2, is planned for the second half of 2012.

Italy

A shale gas / coal seam gas combination play is being investigated by Independent Resources in the Ribolla Basin, Tuscany. Upper Miocene (Messinian) gas shale straddles a coal seam of up to 20' thickness over a distance of tens of kilometers along the basin axis. Farm-out discussions are under way with companies which have experience of analogous plays. In-place and recoverable 2C contingent resources are estimated at 300 Bcf and 160 Bcf, respectively.

Netherlands

The Upper Jurassic Kimmeridge Clay is sufficiently deeply buried in the Central Graben in the northern Netherlands offshore to have reached the gas window. In view of the high well cost and drilling density likely to be required, it seems unlikely that offshore shale gas development will be economic in the foreseeable future unless an existing platform and wells happen to be fortuitously located in an optimal location for shale gas development.

Romania

Chevron and Sterling Resources / TransAtlantic Petroleum have acquired a number of licenses in the Moesian Platform of the East European margin in the south of the country, along the Bulgarian border. The

targets are believed to be shale of Silurian to Lower Devonian age (Tandarei Formation) and Middle Jurassic age (Bals Formation).

Sterling Resources / Transatlantic Petroleum are reprocessing existing 2D seismic to identify a drillable location and evaluate re-entering a legacy well on a Silurian prospect in Sud Craiova Block EIII-7.

Spain

Applications that are presumed to be for shale gas exploration have been submitted in the Basque-Cantabrian Basin (BNK; Realm Energy), Pyrenean Foothills (Cuadrilla Resources) and the Campo de Gibraltar (Schuepbach Energy / Vancast).

The focus of interest appears to be the Basque-Cantabrian Basin. Trofagas Hidrocarburos (BNK) has been awarded two concessions in the basin, Realm (now San Leon) has seven awards plus three applications, Leni Oil & Gas has interests in four and while SHESA (owned by the Basque Energy Board, the regional government of the Basque Country) has interests in a substantial number of permits it seems to be focussing on the Enara permit. There does however appear to be a divergence of opinion regarding the most prospective targets. BNK and Leni believe that the Jurassic is most prospective (probably the Lower - Middle section) while SHESA and Realm are targeting Albian – Cenomanian shales with Realm also indicating that the Eocene and Carboniferous could be prospective.

SHESA and its partners, HEYCO Energy and True Oil, plan to drill two vertical wells, Enara 1 and 2, during the latter half of 2012 to evaluate the Middle Albian – Lower Cenomanian Valmaseda Formation.

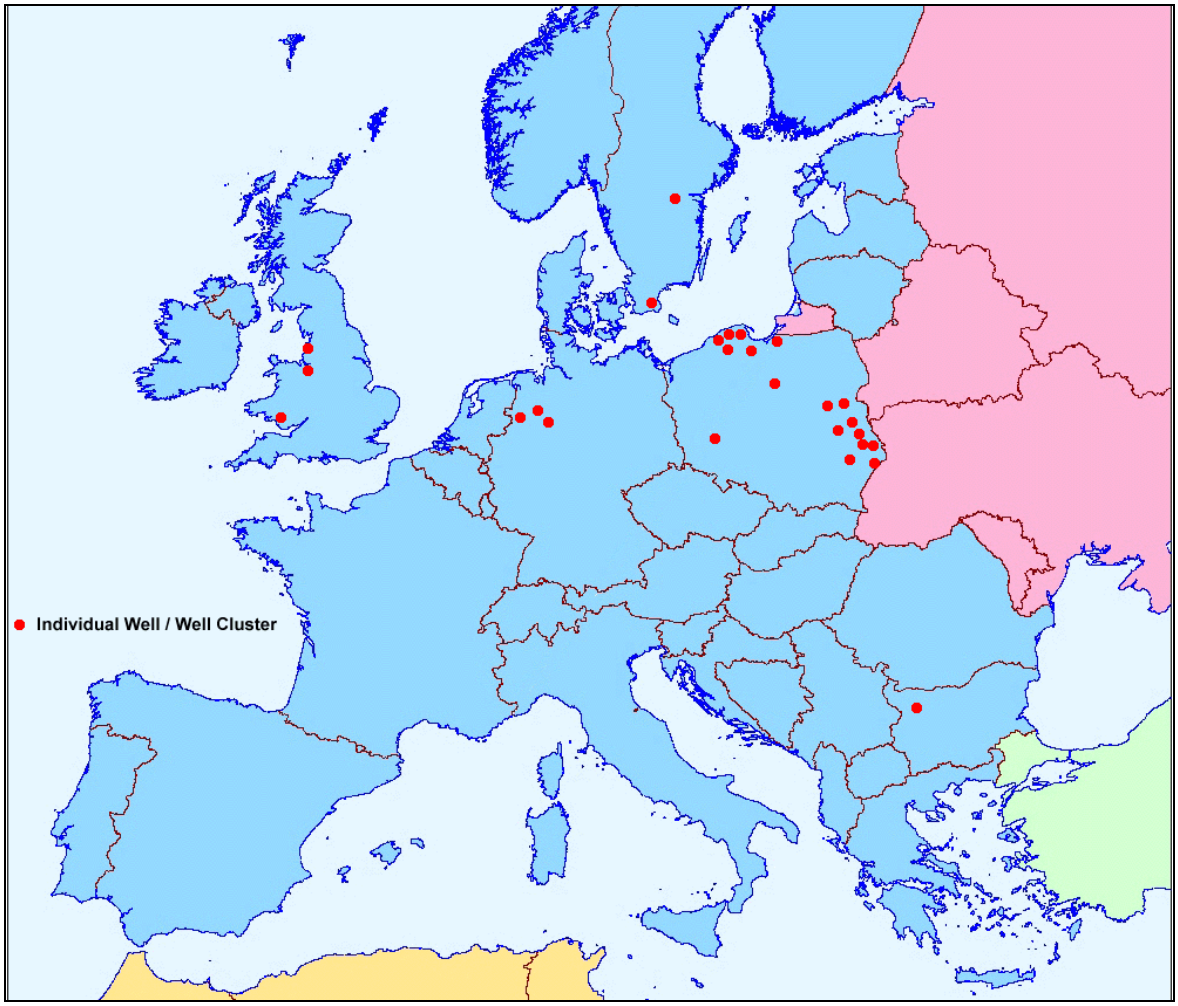
BNK also plans the first well on its Jurassic target in 2012.

Switzerland

In addition to the Lower Jurassic Posidonia Shale, Schuepbach has also targeted the Aalenian (Middle Jurassic) Opalinuston in the Molasse Basin. It is understood, however, that the cantonal authorities in Fribourg will not renew the Fribourg licence when it expires at end-2011, over environmental concerns. Schuepbach still hopes to explore for shale gas in Canton Vaud, to the south of Fribourg.

United Kingdom

The Upper Jurassic Kimmeridge Clay has been proposed as a possible target in the Weald Basin, *England*, but there is considerable doubt that it will be mature for significant gas generation in this basin, although biogenic shale gas may be a possibility. Cuadrilla's interest in the Kimmeridge Clay is for shale oil rather than shale gas. If there is shale gas potential in the basin it seems more likely that it will come from older shales (Rhaetic or older). For example, Esso's 1963 Bolney 1 well is reported to have found a marine Middle Devonian interval within the gas window.



Distribution of known shale gas drilling in Europe. *Base map courtesy of IHS*.

Geological Province	Sub-Province	Concession	Well Name	No	Operator	Companies	Spud	Completed
Bulgaria								
Moesian Platform		A-Lovech	Goljamo Peshtene	R-11	LNG Energy	LNG En; Transatlantic Pet	27-Sep-11	TD end-Nov-1
Germany								
Northwest German Basin	Lower Saxony Basin	Münsterland	Damme	2/2A	ExxonMobil	ExxonMobil; Shell	2008	n/a
Northwest German Basin	Lower Saxony Basin	Münsterland	Damme	3	ExxonMobil	ExxonMobil; Shell	2008	n/a
Northwest German Basin	Lower Saxony Basin	Minden	Oppenwehe	1	ExxonMobil	ExxonMobil; Shell	Jun-08	n/a
Northwest German Basin	Lower Saxony Basin	Schaumberg	Niedernwöhren	1	ExxonMobil	ExxonMobil; Shell	2009	n/a
Northwest German Basin	Lower Saxony Basin	Scholen-Barenburg II	Schlahe	1	ExxonMobil	ExxonMobil; Shell	2009	n/a
Northwest German Basin	Lower Saxony Basin	Bramschen	Lünne	1	ExxonMobil	ExxonMobil; Shell	17-Jan-11	n/a
Northwest German Basin	Lower Saxony Basin	Bramschen	Lünne	1A	ExxonMobil	ExxonMobil; Shell	Mar-11	n/a
Poland								
Baltic Depression	Gdansk Depression	Trzebielino	Miszewo	T-1	Indiana Investments	BNK Petroleum	28-Feb-12	
Baltic Depression	Gdansk Depression	Slawno	Wytowno	S1	Saponis	BNK; RAG; Sorgenia; LNG En	Dec-10	14-Feb-11
Baltic Depression	Gdansk Depression	Slupsk	Lebork	S1	Saponis	BNK; RAG; Sorgenia; LNG En	11-Mar-11	25-Apr-11
Baltic Depression	Gdansk Depression	Starogard	Starogard	S1	Saponis	BNK; RAG; Sorgenia; LNG En	16-Jul-11	Sep-11
Baltic Depression	Gdansk Depression	Lebork	Łebień	LE-1	3Legs Resources	Lane Energy; ConocoPhillips	Mid-Jun-10	28-Jul-10
Baltic Depression	Gdansk Depression	Lebork	Łebień	LE-2H	3Legs Resources	Lane Energy; ConocoPhillips	10-May-11	Jun-11
Baltic Depression	Gdansk Depression	Cedry Wielkie	Łęgowo	LE-1	3Legs Resources	Lane Energy; ConocoPhillips	27-Aug-10	Q4-2010
Baltic Depression	Gdansk Depression	Damnica	Warblino	LE-1H	3Legs Resources	Lane Energy; ConocoPhillips	17-Jul-11	Sep-11
Baltic Depression	Gdansk Depression	Gdansk-W	Lewino	1G-2	Talisman Energy Poland	Oculis / Talisman	26-Sep-11	17-Nov-11
Baltic Depression	Gdansk Depression	Braniewo	Rogity	1	Talisman Energy Poland	Oculis / Talisman	12-Dec-11	14-Feb-12
Baltic Depression	Gdansk Depression	Wejherowo	Lubocino	1	PGNiG	PGNiG	Q4-10	Mar-11
Danish-Polish Marginal Trough	Lublin Trough	Grabowiec	Lesniowice (?)	G6	Chevron	Chevron	31-Oct-11	Q1-2012
Danish-Polish Marginal Trough	Lublin Trough	Frampol	Andrzejow (?)	1	Chevron	Chevron	Mar-12	
Danish-Polish Marginal Trough	Lublin Trough	Chelm	Krupe	1	ExxonMobil	ExxonMobil	03-Dec-10	Q1-2011
Danish-Polish Marginal Trough	Pomeranian Trough	Rypin	Lutocin	1	Marathon	Marathon Nexen / Misui	Early Apr-12	
Danish-Polish Marginal Trough	Pomeranian Trough	Szczawno	Szymkowo	1	Talisman Energy Poland	Oculis / Talisman	07-Mar-12	
Danish-Polish Marginal Trough	Lublin Trough	Pionki-Kazimierz	Markowola	1	PGNiG	PGNiG	Apr-10	Jun-10
Danish-Polish Marginal Trough	Lublin Trough	Tomaszów Lubelski	Lubycza Królewska	1	PGNiG	PGNiG	26-Mar-12	
Danish-Polish Marginal Trough	Lublin Trough	Wierzbica	Syczyn		PKN Orlen	PKN Orlen	24-Oct-11	n/a
Danish-Polish Marginal Trough	Lublin Trough	Lubartów	Berejow		PKN Orlen	PKN Orlen	Mid-Dec-11	
East European Platform Margin	Podlasie Depression	Minsk Mazowiecki	Siennica	1	ExxonMobil	ExxonMobil	20-Feb-11	Apr-11
East European Platform Margin	Podlasie Depression	Orzechow Area A	Cycow	1	Marathon	Marathon Nexen / Misui	Q4-11	n/a
East European Platform Margin	Volhyno-Podolian Monocline	Siedlce	Domanice	1	Marathon	Marathon Nexen / Misui	Q1-12	n/a
Fore-Sudetic Monocline		Gora	Siciny	2	Gora Energy Resources	San Leon	10-Nov-11	Mid Feb-12
Sweden								
Fennoscandian Border Zone		Colonussänkan	Lövestad	A3-1	Shell	Shell	28-Nov-09	n/a
Fennoscandian Border Zone		Colonussänkan	Oderup	C4-1	Shell	Shell	n/a	n/a
Fennoscandian Border Zone		Colonussänkan	Hedeberga	B2-1	Shell	Shell	n/a	n/a
Östergötland		Motala area	3-5 wells		Aura Energy	Aura Energy	Early Oct 11	n/a
United Kingdom								
Cheshire		PEDL 190	Ince Marshes	1	Igas	Igas	04-Nov-11	21-Jan-12
East Irish Sea Basin	West Bowland Basin	PEDL 165	Grange Hill	1	Cuadrilla	Cuadrilla	15-Jan-11	15-Apr-11
East Irish Sea Basin	West Bowland Basin	PEDL 165	Grange Hill	1Z	Cuadrilla	Cuadrilla	15-Apr-11	Early Aug 201
East Irish Sea Basin	West Bowland Basin	PEDL 165	Becconsall	1	Cuadrilla	Cuadrilla	23-Aug-11	13-Oct-11
East Irish Sea Basin	West Bowland Basin	PEDL 165	Becconsall	1Z	Cuadrilla	Cuadrilla	13-Oct-11	21-Dec-11
East Irish Sea Basin	West Bowland Basin	PEDL 165	Preese Hall	1	Cuadrilla	Cuadrilla / A J Lucas	16-Aug-10	08-Dec-10
South Wales Carboniferous		PEDL 148	Banwen	1	UK Methane	UK Methane	07-Sep-11	n/a
South Wales Carboniferous		PEDL 149	St Johns	1	UK Methane	UK Methane	26-Aug-11	n/a

Shale gas exploration wells drilled in Europe

Some general gas resource play issues

Most plays are "statistical" in nature. Every coal unit and shale unit is "different" and also generally displays inhomogeneity. Statistical distributions can be obtained for parameters such as estimated ultimate recovery (EUR) and peak production from analagous wells. With a large enough sample size (number of wells) the geology of the play and the best drilling and completion strategies can be understood sufficiently well to make performance of a play and its recoverable resources predictable. European exploration is still some considerable way from achieving these levels of understanding.

To convert recoverable resources into reserves requires good technology: smart wells; fracture and stimulation; real-timer micro-seismic mapping.

Shale oil in Europe

The principal shale oil (tight oil) target in Europe is the Liassic (Lower Jurassic) which is considered by many to be an analogue to the Bakken Formation of the Williston Basin. It is being investigated in France, Germany, The Netherlands and Portugal. The Upper Jurassic is understood to be a target in the south of the United Kingdom and central Poland, while a liquids-rich area has also been identified in the Polish Lower Paleozoic play.

France

In the Paris Basin, Toreador Resources is investigating the fractured shale oil potential of a Liassic (Lower Jurassic) interval. The Liassic section is similar to the Bakken Formation in that the bituminous shales also contain a middle calcareous member (Banc de Roc). Shows have previously been detected in 11 conventional exploration wells drilled from the 1950s onwards and 6 wells have produced oil on test. On 10th May 2010 Toreador signed an investment agreement with Hess whereby each partner will hold a 50% interest in Paris Basin unconventional oil exploration and production (see *4.3 Ownership Transactions: Farm-ins*).

There are four Liassic targets in the basin: Schistes Carton (Toarcian); Banc de Roc (Pliensbachian); Amaltheus Shale (Pliensbachian); Sinemurian-Hettangian Shale.

Toreador / Hess had planned to drill six wells in 2011, at least two of them horizontal, but as a result of the French government study into the economic, social and environmental impact of shale gas and shale oil drilling and the introduction of the resultant legislation, the program was suspended. A three (3) vertical well drilling program, operated by Hess, is now expected to commence in 2012 but it is unclear whether this will test the Liassic play.

In spring and autumn 2010 Vermilion Energy fracture tested two vertical wells in the Toarcian Schistes Carton, producing 32 - 38° oil from both wells. In February 2011 these wells were believed to be producing about 63 bbl/d. Vermilion had planned to drill another two vertical wells in 2011 to evaluate all four zones and to drill a horizontal well in 2012 based on 2011 results but it is understood that Vermillion has now suspended all Paris Basin shale oil evaluation activity. On 22nd September 2011, Vermillion withdrew three permit applications in the Paris Basin, possibly as a consequence on the ban on hydraulic fracturing introduced on 13th July 2011 (see *5. Above-Ground Issues: France*).

Realm Energy (now wholly-owned by San Leon), although focused on shale gas, has shale oil potential on the nine permits for which it has applied in the Paris Basin. If awarded, ConocoPhillips will farm into the permits but Realm will remain operator initially (see *4.3 Ownership Transactions: Farm-ins*). Realm has indicated that the Toarcian Schistes Carton may also have shale oil potential within the area of its Blyes permit application in the Bresse-Valence Basin.

Germany

Outcrop work by BNK Petroleum has identified samples of the Toarcian-age Posidonia Shale with thermal maturities ranging from below the oil window to within the gas window. It therefore seems probable that over some of BNK's acreage the Posidonia Shale will fall within the oil window and have potential for tight shale oil. Although BNK has not indicated which of its six German concessions have shale oil potential, the most likely candidate seems to be the Wolfsburg concession in Lower Saxony.

Netherlands

Cuadrilla Resources, in partnership with Dutch state company EBN, is targeting multiple unconventional hydrocarbon prospects on its Noord Brabant concession. The first well to be drilled (Boxtel-1) will evaluate the shale oil potential of the Posidonia Shale (Lower Toarcian) in the Roer Valley Graben at a depth of about 11,500'.

Poland

Silurian Energy Services, a subsidiary of Silurian Hallwood, has four of the most easterly concessions in the Gdansk Depression, along the border with the Russian enclave of Kaliningrad, where Lukoil has been producing conventional oil for some time. As is noted above, these concessions appear to be situated in a more liquids-prone part of the basin (see *2.1.1 Lower Paleozoic: Poland*). In addition to tight shale oil, Silurian Hallwood expects there to be conventional prospects in Cambrian and Ordovician carbonates.

In 2011, Hutton Energy's Polish subsidiary Strzelecki Energia acquired three concessions in the Mogilno-Łódź Trough of the Northeast German-Polish Basin in central Poland. In addition to conventional traps in Jurassic and Triassic sandstone, the company considers that the concessions have unconventional oil and gas potential in Jurassic shale, most probably of Late Jurassic age.

Portugal

On 1st March 2012, Porto Energy Corp., holder of five licences on and offshore the Lusitanian Basin, announced that it had entered into a definitive joint venture agreement with Sorgenia International of the Netherlands and Austria's Rohöl-Aufsuchungs Aktiengesellschaft (RAG) to evaluate the unconventional resource potential of the Lower Jurassic (Liassic) basal Brenha Formation within Porto's concessions. The organic-rich Lias is the source of oil seeps along the coast and has historically been surface mined for bitumen.

United Kingdom

Cuadrilla Resources plans to investigate the shale oil potential of the Upper Jurassic Kimmeridge Clay in its Bolney project on PEDL 244 in the Weald Basin, southern England, where Esso found gas shows at shallow depth in Bolney-1 (1963). In April 2010 Cuadrilla received planning permission to drill the Lower

Stumble test of the Kimmeridge Clay using the well pad of Balcombe-1, drilled by Conoco in 1986 on the Bolney (Lower Stumble) anticline. Top Kimmeridge Clay is estimated to occur at a depth of around 1,800' at this location.

In May 2011, AJ Lucas reported that Cuadrilla had fracced the Cowden 2 gas discovery well in the Weald Basin. The well was drilled by Independent Energy in August 1999 on a separate licence, EXL 189. The results were said to be inconclusive. It is not known if this was a test of the well's shale oil or shale gas potential since an oil discovery, Lingfield-1, was also made within the EXL 189 licence area in 1999. AJ Lucas indicated that a further well would be drilled later but it is unclear whether this refers to the Lower Stumble shale oil test on PEDL 244 or a well on EXL 189.

Ownership transactions

There have been a substantial number of business deals in Europe as late entrants try to gain a foothold in promising acreage and smaller companies seek additional financing. Full company M&A activity has been relatively slight with most transactions taking the form of licence purchases or farm-ins.

Company mergers, acquisitions and restructuring

On 28th February 2011, Dart Energy Ltd. of Australia announced that it would acquire with immediate effect the 90% of the shares in the UK's Composite Energy Ltd. that it did not already own. Although primarily a coal seam gas explorer, Composite Energy had acreage with shale gas potential in both Scotland and Poland. On takeover, Composite Energy became Dart Europe Ltd.

On 10th August 2011, Toreador Resources Corp. announced a merger with ZaZa Energy LLC of Houston, TX, combining ZaZa's Eagle Ford and Eagle Ford/Woodbine ("Eaglebine") interests with Toreador's Paris Basin interests. The new company will be called ZaZa Energy Corp.

On 26th August 2011, the UK's San Leon Energy plc and Canadian company Realm Energy International Corp. announced an agreement whereby San Leon will acquire all of the shares of Realm, resulting in Realm becoming an indirect subsidiary of San Leon. The acquisition was completed on 10th November 2011. On completion of the deal, San Leon acquired 3 licences in Poland, 1 in Germany and 7 in Spain. In addition Realm had 10 outstanding licence applications in France and 3 applications in Spain. With the exception of 9 applications in the Paris Basin focused on shale oil, the primary target of the Realm licences and applications was shale gas.

Eden Energy Ltd. has announced that it plans to spin out Eden Energy (UK) into a new proposed Australian Stock Exchange listing, Adamo Energy Ltd., when market conditions are suitable. Adamo will have an unrisked shale gas in place resource of 24.9 Tcf (net to Adamo) in South Wales / southern England.

On 16th January 2012, Dart Energy announced the formation of Dart Energy International Shale. This wholly-owned subsidiary will manage and develop the company's growing portfolio of shale gas interests. At present these are held entirely in Europe.

Licence acquisitions

Germany

On the 23rd December 2011, in the course of acquiring BG's UK coal seam gas interests, Dart Energy obtained an exclusive three month option to acquire for no additional consideration a 100% interest in two

licence areas in Germany (Saxon I and Saxon II) currently held 100% by BG Group, which are prospective for both CBM and shale gas.

Poland

On 15th November 2010, the UK's San Leon Energy plc announced that it had agreed to acquire Mazovia Energy Resources (a EurEnergy Resources Corp. subsidiary), holder of three concessions in the Fore Sudetic Monocline, southwest Poland. The concessions are thought to have Carboniferous shale gas potential.

On 10th December 2010, Eni S.p.A. announced that it had agreed to acquire Minsk Energy Resources (a EurEnergy Resources Corp. subsidiary), holder of three concessions in the Baltic Depression.

On 28th December 2011, Dart Energy announced that it had secured an exclusive option over a 20% interest in the Szczawno concession in the Baltic Depression held by Greenpark Energy Ltd.

Spain

On 28th December 2011, Dart Energy announced that it had secured an exclusive option over a 90% interest in the Pisuergo licence held by Greenpark Energy Ltd.

United Kingdom

On 28th December 2011, Dart Energy announced that it had agreed to acquire all of the unconventional gas assets of Greenpark Energy Ltd., comprising 22 onshore licences in the UK. Seven of these licences are considered to have shale gas potential.

Farm-ins

Bulgaria

On 29th August 2011, LNG Energy Ltd. announced that it had entered into an agreement with TransAtlantic Petroleum Ltd. to earn a 50% interest in the A-Lovech exploration licence in northwest Bulgaria. LNG Energy will provide up to US$ 7.5 million to drill, core and test a 10,500' Middle Jurassic shale gas exploration well. Closure of the deal was announced on 22nd September.

France

On 10th May 2010, Toreador Resources Corp. and Hess Corp. announced an agreement, whereby Hess will make a $15 million upfront payment and invest up to $120 million in a two-phase work program on Toreador's awarded and pending shale oil exploration permits in the Paris Basin. Phase 1 will consist of an evaluation of the acreage and drilling of six wells. Depending on the results of Phase 1, Phase 2 is expected to consist of appraisal and development activities. Following Phase 2, provided contractual obligations have been met, Hess will hold a 50% share of Toreador's working interest in the covered permits.

On 15th July 2011, Realm Energy International Corp. (now San Leon) announced that it has entered into a farm out agreement with ConocoPhillips covering its nine exploration licence applications in the Paris Basin. The agreement provides Realm with a limited carry on exploration expenditure conditional on actual

acreage acquired and required activity commitments. Realm is designated operator for the initial exploration phase with ConocoPhillips having an operatorship option thereafter. The nine licences are considered to be primarily prospective for tight oil.

Poland

In August 2009, ConocoPhillips reached an agreement to farm into 3Legs Resources' six Baltic Depression concessions. ConocoPhillips is funding the initial exploration and evaluation programme but 3Legs Resources remains the operator. ConocoPhillips had until 20th March 2012 to determine whether to exercise an option to take a 70% interest in the concessions. If exercised, operatorship would transfer to ConocoPhillips.

On 20th March 2012, 3Legs Resources announced that ConocoPhillips will exercise its option in respect of the three western concessions. Completion of the option exercise must take place no later than September 2012, whereupon operatorship of the three western concessions will pass to ConocoPhillips. It was also announced that the two companies are considering options for the three eastern Baltic Depression concessions which are situated in a more liquids-prone part of the basin (see *2.1.1 Lower Paleozoic: Poland*). In order to develop an appropriate strategy for the three eastern concessions, they will be divested into a separate Polish legal entity, which will be a wholly-owned subsidiary of 3Legs Resources. ConocoPhillips will retain an option to acquire a 70% interest in the three eastern concessions, exercisable by giving six months' notice at any time up until 30 September 2012.

On 1st March 2010, Irish company San Leon Energy Ltd. disclosed that it had entered an agreement with Talisman Energy Inc. whereby Talisman will acquire a 60% interest in San Leon's three Baltic Depression concessions in exchange for covering 60% of the cost of a seismic programme and drilling one well on each of the three concessions with an option to follow up with a further three wells. If the second three wells are not drilled, Talisman's interest will reduce to 30%.

On 26th April 2011, Marathon Oil Corp. announced that Nexen Inc. will take a 40% interest in 10 of Marathon's 11 concessions in the Lower Paleozoic play, eastern Poland. On June 9th 2011, Mitsui & Co. Ltd. reported that it had agreed to acquire a 9% interest in the 10 concessions, reducing Marathon's interest to 51%. Marathon remains operator. The one concession excluded from the farm-outs is Plonsk SE in the Danish-Polish Marginal Trough.

On 13th May 2011, Total SA announced an agreement with ExxonMobil to farm in to two concessions in the Lublin Trough, Danish-Polish Marginal Trough. Total will acquire a 49% interest while ExxonMobil retains a 51% interest and operatorship. The farm-in was approved in July 2011.

On 14th August 2011, Hutton Energy plc (formerly BasGas Pty Ltd.) announced that through its Polish subsidiary Strzelecki Energia it intended to take a 49% interest in four ExxonMobil concessions in the Podlasie Depression of the East European Platform margin. ExxonMobil would retain 51% and operatorship. Although the deal was approved subsequently by the Polish Office of Competition and Consumer Protection, the deal was never closed.

Unconfirmed reports suggested that Polish independent PKN Orlen was at one time in discussions with Encana with a view to exchanging an interest in some of Encana's North American shale gas acreage for access to PKN Orlen's Polish shale gas concessions. Orlen has seven shale gas concessions in Poland plus one with tight gas potential.

It has also been reported that Italian major Eni was considering taking an interest in LOTOS Petrobaltic's seven offshore shale gas concessions.

Above-ground issues

There are a number of issues that face most gas resource play developments. Per-well reserves and productivity can be low and benefit from an established gas compression and distribution infrastructure.

To convert resources into reserves also requires large numbers of wells. Some North American resource plays employ 10-acre spacing as opposed to the 640-acre spacing typical of conventional wells. This could pose a problem in densely populated areas of Europe but horizontal wells drilled from a single pad can be used to reduce the well footprint. In British Columbia's Horn River Basin, Apache Corp.'s well design concept should recover gas from two different stratigraphic intervals over an area of 7 km^2 from a single 28-well pad.

Other environmental issues such as water availability and water disposal capacity may also impact on ultimate recovery.

Almost inevitably, the concerns that have been raised in the U.S. about potential contamination of groundwater supplies from chemicals used in hydraulic fracturing of shale gas reservoirs are being echoed in Europe. In addition, the potential of fracing to induce local seismicity has also been raised. A major public misconception appears to be that the word "unconventional" implies new, untested, and therefore risky, drilling and completion technology.

Public disquiet has manifested itself in a number of countries, most notably Bulgaria, France and Germany. The issues have now entered the political realm, creating a further condition of uncertainty. While vested commercial interests (e.g. the coal, nuclear and renewable energy industries; importers of conventional gas; natural gas storage operators) are almost certainly a factor, populism in advance of elections is undoubtedly playing a part and environmental groups are using the controversy to advance their own agendas. Until there is public recognition that the drilling and fracturing technology that is in use has been applied for decades in hundreds of thousands of wells and that all that is "unconventional" is the mode of subsurface occurrence of the natural gas, there are likely to be deferrals and delays in the evaluation of shale gas potential in a number of countries. It remains a problem of perception. "People overestimate the dangers of what is new and underestimate those of what they're used to" (Rudolf Huber, CEO of NeXtLNG Ltd.).

The commissioning on 8th November 2011 of the first of two 1,224 km (760-mile) Nord Stream gas pipelines across the Baltic Sea from Portovaya Bay in Russia to Lubmin in Germany, effectively created a divergence of interests between the western European countries served by Nord Stream (e.g. Germany; Denmark; U.K.; The Netherlands; Belgium; France; Czech Republic) and those countries still dependent on Russian gas from the overland route transiting through Ukraine (e.g. Poland; Bulgaria; Romania). Gazprom's announcement that it is considering a third Nord Stream pipeline and its downbeat remarks about European shale gas exploitation suggest that it sees shale gas development in Europe as a threat to its position as largest gas supplier to the continent and is keen to divert governments away from shale gas and back towards Russia as a guaranteed supplier.

International Energy Agency

Conscious of the impact that negative publicity has on realizing the potential of unconventional gas, on 29th May the Paris-based International Energy Agency plans to release in London a World Energy Outlook special report on "Golden Rules" that are needed to support a potential "Golden Age of Gas". The report will provide insight into the environmental challenges linked to unconventional gas production and how best to deal with them.

European Union

On 4th February 2011, the European Council announced a number of priority actions in its Conclusions on Energy (PCE 026/11). Priority 7 stated "In order to further enhance its security of supply, Europe's potential for sustainable extraction and use of conventional and unconventional (shale gas and oil shale) fossil fuel resources should be assessed."

In September 2011, the EU Energy Commissioner, Guenther Oettinger of Germany, said that he hopes to put forward proposals in spring 2012 to standardise regulations on hydraulic fracturing. This followed a report published in July for the European Parliament by six German authors entitled *Impacts of shale gas and shale oil extraction on the environment and on human health*. Herr Oettinger's announcement produced a strong reaction from the Polish Treasury Minister who stated that exploration for unconventional hydrocarbon resources is already adequately regulated and that the possibility of European Union wide regulation is not provided for in the Lisbon Treaty (Treaty on the Functioning of the European Union or TFEU). (Both the Lisbon Treaty and the Energy Treaty Charter recognise state sovereignty in the use of a county's energy resources.) On 22nd September 2011, Herr Oettinger's spokeswoman, Marlene Holzner, said that the commission is studying whether the current European Union environmental laws would apply to shale gas production, but isn't planning to propose any new legislation.

On 13th October 2011 EU Climate Action Commissioner, Connie Hedegaard, said that she was not inclined towards a moratorium on shale gas drilling based on the information that she had heard so far.

The Commission selected a Brussels law firm, Philippe & Partners, to analyse how the relevant applicable European legal framework, including environmental law, is applied to the licensing, authorisation and operation of shale gas exploration and exploitation, using a sample of four Member States, France, Germany, Poland and Sweden. The 104-page report was published on 8th November 2011. On 27th January 2012 Energy Commissioner Oettinger stated that "the legal study confirms that there is no immediate need for changing our EU legislation."

Separately from the European Commission, however, the German chairman of the European Parliament's committee on the Environment, Public Health and Food Safety indicated in July that he wants a new "energy quality directive" that would introduce stringent regulations to cover fuels with what are deemed to be adverse environmental impacts – tar sands oil and shale gas among them.

Background comment. Individual EU member states have the right to determine exploitation of energy resources and their energy mix (TFEU Article 194). Member states are also free to set more stringent environmental protection measures than required by EU legislation (TFEU Article 193). Most aspects of hydrocarbon exploration and production are covered by existing EU legislation: Hydrocarbon Directive; Water Framework Directive; Groundwater Directive; Environmental Impact Assessment; Registration, Evaluation, Authorisation and Restriction of Chemical substances (REACH); Natura 2000 (protected areas); and other regulations covering waste, noise etc.

Austria

OMV's plans to drill one or two shale gas exploratory wells in the wine quarter of Lower Austria have run into substantial opposition. Despite seeking community support, the company's plans were resisted not only by environmental and community groups but also by politicians, including the Environment Minister and Governor of Lower Austria. On 2nd March OMV announced that it would suspend drilling plans pending the completion of a comprehensive environmental and social study by the Federal Environmental Agency and TÜV Austria Group, a technical and environmental safety consultancy.

Bulgaria

The shale gas debate featured in the October 2011 presidential elections with the two principal opposition candidates both indicating that they opposed shale gas development. The election was won, however, by the candidate of the ruling party (Citizens for European Development of Bulgaria). Environmental organisations and opposition parties wished to impose a temporary moratorium on shale gas exploration and have called for a referendum on allowing such activities. Although the Ministry of Economy, Energy and Tourism has indicated that it plans a thorough assessment of the risks involved in shale gas development it appears to be broadly supportive of shale gas exploration. On 19th October 2011, a delegation representing a number of ministries and regional governors visited Poland to learn from the Polish experience.

In the face of massive public protests, on 18th January 2012 parliament placed an indefinite ban on the use of hydraulic fracturing. The previous day, prior to final execution of the licence agreement, the government announced the withdrawal of a permit for shale gas exploration awarded to Chevron in June 2011. Chevron continues in discussions with the government to provide assurances that hydrocarbons can be produced safely from shale.

The Minister for Economy and Energy has said that he believes powerful financial interests were behind the mass protests. The pro-Russian Centre Left party played a leading role in opposing shale gas research. (Gazprom provides 98% of Bulgaria's gas.) Since the moratorium was imposed a Movement for Energy Independence has been established and has called for cancellation of the moratorium.

Czech Republic

The Náchod District assembly and some 50 local administrations have submitted formal objections to the Ministry of Environment's award of the Trutnov permit to Basgas Energia Czech, a subsidiary of Hutton Energy.

France

In February 2011, shale gas and shale oil drilling in France was suspended by the authorities pending a progress report on the environmental consequences of shale exploitation. The ultimate outcome of this process was the passing of a law on 13th July 2011 that prohibited the exploration for, and production of, liquid or gaseous hydrocarbons by hydraulic fracturing. Permit holders had two months in which to advise the administrative authorities of the techniques that they use or intend to use in their exploration activities. Failure to respond or an intention to use hydraulic fracturing would result in withdrawal of the permit. A national commission will also be established to evaluate the environmental risks associated with hydraulic fracturing and to set out the conditions under which scientific research under public control can take place. The government will report annually to parliament on the evolution of exploration and production technology in France, Europe and internationally and also on the results of the scientific research undertaken.

In September 2011, major French E&P company Total S.A. announced as part of its report to the authorities that it would continue the evaluation of its Montélimar exploration licence but that the work programme does not envisage the use of hydraulic fracturing. Other companies were expected to adopt a similar approach.

On 3rd October the ministers of Ecology, Sustainable Development, Transport & Housing and Industry, Energy & the Digital Economy announced in a joint press release that the three permits issued specifically

for exploration for shale gas would be cancelled. These are the Total S.A. Montélimar exploration and the Schuepbach Villeneuve-de-Berg and Nant licences. Total expressed surprise as it had undertaken not to use hydraulic fracturing and was awaiting the government's notification to understand the legal basis for the cancellation. The official confirmation of the repeal of the three licences was gazetted on 13th October 2011. On 26th November the CEO of Total S.A. announced that the company would appeal against the revocation of the Montélimar licence and on 12th December the company filed an appeal in the Paris Administrative Court in order to clarify the situation, on the grounds that the company had complied with the Act of July 13th 2011.

The French Union of Petroleum Industries declared that the cancellation decisions will send a negative signal to international investors and are prejudicial to an economy which imports 99% of its oil and 98% of its gas consumption. The CEO of French company GDF Suez said that while it was appropriate that the government evaluate technology and processes, closing the door forever to shale gas development would be "a major mistake".

On 11th October 2011 the National Assembly rejected a bill submitted by the parliamentary opposition which set out to prohibit exploration for, and exploitation of, unconventional hydrocarbons irrespective of the techniques used. The proposed bill was deemed to contain several flaws and to be incompatible with the law of 13th July 2011.

It remains possible that the shale gas debate will be renewed once the April / May 2012 French presidential election has taken place.

Background comment. In 2007, 78% of all French electricity production came from nuclear power. Two new European pressurised water reactors (EPRs) are due to be commissioned by 2017, so it can be assumed that the nuclear industry will not be supporting shale gas development!

Germany

Fracing was first used in conventional wells in 1955 (Schleswig-Holstein) and 1977 (Lower Saxony). Between 1977 and 2010 some 140 frac operations were conducted in Germany. The first fracing of unconventional gas wells (tight gas) occurred in the mid-1990s in the Söhlingen Field, Lower Saxony, and fracing was conducted in at least three other tight gas fields in Lower Saxony in the period 2005-2010. Despite a 55-year history of fracing, there was no public interest in the application of the technology in Germany until 2010.

Unlike France, where governance is highly centralised, the German Länder (constituent states of the Federal Republic of Germany) have a high degree of autonomy. The political strength of the Grüne (Green environmental party) is at an all-time high both federally and at state level, and environmental groups have exerted considerable pressure on politicians in areas where shale gas development is proposed. In March 2011 the state Environment minister of North Rhine-Westphalia, a member of the Grüne, introduced a moratorium on shale gas exploration. To date, however, most shale gas exploration has taken place in Lower Saxony, which has not introduced such a moratorium.

The Minister for Environmental Protection in the federal government announced on 29th July 2011 that an expert survey on the environmental impact of shale gas production will be ordered and that changes to the geological and mining laws are likely. On 4th August 2011 the Federal Environment Agency published an opinion entitled *Einschätzung der Schiefergasförderung in Deutschland* (Assessment of shale gas production in Germany). The report is generally negative towards shale gas and appears to selectively quote, for example, sources such as the Tyndall Centre for Climate Change at the University of Manchester and Robert Howarth at Cornell University that are generally considered to exaggerate the impact of natural gas as a source of greenhouse gas emissions. If the planning and legislative requirements proposed in the

report are implemented, they will probably have the effect of making shale gas production uneconomic in Germany.

Background comment. The German unconventional hydrocarbons industry is not well developed and domestic companies lack the necessary technology. These companies are focused on the production, importation and storage of conventional gas. Germany also has a substantial renewable energy industry. All of these interests would be threatened by large volumes of low-cost indigenous natural gas. It is therefore in the interests of German industry not only to make shale gas production as unprofitable as possible in Germany but to use its influence to restrict large-scale gas production elsewhere in Europe (see the direction of the German strategy in the *European Union* above).

Ireland (Republic of Ireland)

The principal prospect in Ireland lies in the Northwest Ireland Carboniferous Basin (Lough Allen Basin), which straddles the border between the Irish Republic and Northern Ireland but most of the opposition has come from the Republic side. At a company information meeting in early September 2011, the operator, Tamboran Resources, offered to conduct fracing without chemical additives but this did nothing to soften the opponents of the scheme. The government subsequently asked the Environmental Protection Agency to conduct a study on the effects of fracing. The major environmental trust, An Taisce, has called for fast track regulation to clarify the currently uncertain regulatory position regarding onshore drilling.

Netherlands

Although the provincial authorities in Noord Brabant were opposed to Cuadrilla Resources' plans to drill two wells, in early 2011 the Dutch Minister for Economic Affairs, Agriculture and Innovation granted a licence for drilling to proceed. (The Dutch state, through its wholly-owned company EBN, has a 40% interest in the licence.) On June 29th, however, the ministry indicated that shale gas exploration in the Netherlands will not move ahead until the results of the UK's inquiry into hydraulic fracturing have been assessed. "If it appears that there are unacceptable risks, no drilling for shale gas will occur," the Minister, Maxime Verhagen, said in a letter to parliament. "Concerns regarding shale gas are understandable and I take them very seriously."

In October 2011, Cuadrilla encountered another setback when a court ruled that Boxtel town council was wrong to grant a temporary exemption from zoning for its Boxtel-1 well since that was based on activities concluding within five years and, if commercial production had been established, it was likely that operations would exceed this time span. Cuadrilla must now return to Boxtel council to resolve the situation and their spokesman expected a few months' delay to a well that was due to spud early in 2012. The most recent company estimate is that this well will not now spud until 2013.

Poland

Unlike most other countries the major political debate in Poland has been about maximising the benefit of shale gas exploitation to the state. In advance of the October 2011 parliamentary election, the opposition Law and Justice Party prepared draft legislation covering Polish shale gas. In the election, however, the ruling Civic Platform–Polish People's Party coalition won sufficient seats to continue in government. There are moves to create a new Energy and Environment Ministry but removing Energy from the Economy Ministry would be resisted and the Polish People's Party, the junior partner, therefore favours incorporating

Environment into the Economy Ministry. Changes to government seemed unlikely until Poland's six-month term as President of the European Union ended on 31st December 2011.

Draft proposals regarding a hydrocarbon extraction tax should be available in Q2-2012 but will take some time to be implemented.

More contentious, however, has been the licensing regime and the process of granting shale gas concessions, with six persons, three Ministry of Environment officials and three company employees, detained and released on bail on suspicion of offering or receiving bribes for the allocation of licences. *The Economist* has noted that the existing rules were designed for a system in which a small number of state-controlled companies were operating, and not for the current exploration environment. With most of the prospective shale gas acreage now under licence, however, any changes will be taking place after the horse has bolted.

Romania

The protests in Bulgaria (above) have been echoed in Romania. Bulgarian activists demonstrated outside the Romanian embassy in Sofia (capital of Bulgaria) and have been in contact with like-minded groups in Romania. The Barlad municipality, where Chevron plans to drill later in 2012, opposed shale gas exploration and some members of the parliamentary opposition have filed a legislative initiative which, if passed, would ban hydraulic fracturing. Upcoming local elections are doubtless an additional factor in creating a forum for opposition.

Sweden

In the September 2010 parliamentary election campaign the opposition centre-left alliance comprising the Social Democrats, the Left Party and the Green Party pledged to oppose large-scale fossil fuel production in Sweden, including Shell's planned exploitation of shale gas in southern Sweden. In the event, the ruling centre-right Alliance coalition was re-elected.

Switzerland

In Switzerland, the cantons have a substantial degree of independence and E&P is solely a cantonal responsibility. The Swiss Federation could have an indirect influence on shale gas through its responsibility for environmental legislation but there is no legislation specifically targeted at shale gas at the present time. The federal government's environmental focus is currently on carbon capture and storage (CCS).

In April 2011 the cantonal authorities in Fribourg suspended all shale gas prospecting activities and refused the renewal of Schuepbach's exploration licence, due to expire at end-2011. The explanation given was that the environmental impact and pollution risk accompanying drilling had not yet been clearly identified and that the canton preferred to focus on renewable energies. In the canton of Jura, the Green party has questioned the authorities on their policies regarding shale gas. In Neuchatel the Grand Council has decided that in the event of a discovery, in principle an exploitation concession will be awarded to Celtique Energie and that shale gas is not specifically excluded from this decision. The Celtique Energie web site, however, suggests that their only unconventional prospects (shale oil and shale gas) are in the Weald Basin in southern England.

United Kingdom

On 24th November 2010, the House of Commons Energy and Climate Change Committee launched an evidence-based enquiry into the prospects for shale gas in the UK, the risks and hazards associated with shale gas, and the potential carbon footprint of large-scale shale gas extraction. The committee visited Fort Worth and Austin, Texas, Washington, DC, and two Cuadrilla Resources drilling sites near Blackpool, Lancashire.

The voluminous report (223 pages in two volumes) which was published on 23rd May 2011 produced a number of conclusions and 26 recommendations. In its summary, however, the committee stated that "on balance, we feel that there should not be a moratorium on the use of hydraulic fracturing in the exploitation of the UK's hydrocarbon resources, including unconventional resources such as shale gas" (House of Commons Energy and Climate Change Committee, 2011).

Nevertheless, a number of issues have arisen in the United Kingdom.

On 21st October 2011, the Vale of Glamorgan Council (south Wales) rejected a planning application submitted by Coastal Oil & Gas to drill Llandow-1, a shallow (2,600') conventional and shale gas exploratory well situated on an industrial estate. Despite Environment Agency Wales indicating that it had "no objection to the application as submitted", the Welsh Government declining to get involved as the issues were "not of more than local importance" and the application itself stating "This application does **not** include fracing", the local environmental group "The Vale says No" supported by the local member of the UK Parliament put sufficient pressure on the councillors to ensure that all 17 members of the planning committee opposed the application. Although in debate the councillors spoke of their concerns about pollution if fracing followed a positive exploration outcome, this does not represent a valid reason for rejection. The official reason given was therefore that "the applicant has submitted insufficient information to satisfy the Local Planning Authority that the quantity and quality of groundwater supplies in the vicinity of the site, would be protected". The council leader indicated subsequently that better guidelines were required from the Welsh Assembly (regional government) for test drilling and fracing.

As was indicated above (*2.1.2 Shale gas in Europe: Carboniferous*), fracing operations at Cuadrilla Resources' Preese Hall drilling site were halted after two small earthquakes (2.3 and 1.5 Richter Local Magnitude) were reported on 1st April and 27th May 2011. The British Geological Survey (BGS) has subsequently determined that the earthquakes at depths of 12,000' and 6,500' were within a few thousand feet of the drilling site and that the correlation between the earthquakes and their proximity to and the timing of hydraulic fracing operations pointed to the earthquakes being the result of the fracing process. On 2nd November 2011, Cuadrilla presented a geomechanical report on the causes of the seismicity and future mitigation procedures to the Department of Energy and Climate Change (DECC). The report concluded that the repeated seismicity resulted from direct injection of fluid into the same critically-stressed fault zone and that this can be avoided in future by rapid flowback after treatment and reduction in treatment volume, accompanied by real time seismic monitoring to initiate appropriate action when seismic magnitude exceeds pre-defined thresholds. The DECC sought input from the BGS and other expert sources before taking any decision (expected April / May 2012) on the resumption of fracing operations. A BGS spokesman has however indicated that earthquakes of the magnitude reported in Lancashire have been occurring for hundreds of years as a result of coal mining and generally go unnoticed.

On December 6th 2011, the Northern Ireland Assembly passed a motion calling for a moratorium on hydraulic fracing. But no legislation exists to compel a Northern Irish Minister to act upon a moratorium and as the Minister for Enterprise, Trade and Investment has pointed out, no application has been submitted. She will, however, be in a difficult position if one is submitted.

Background comment. A more general concern on the part of United Kingdom environmentalists, including the DECC's government minister Chris Huhne, is that development of an extensive low-cost shale gas industry threatens the development of renewable energy within the country, by rendering the latter uneconomic. There is also the argument on the one side is that gas provides the most sustainable bridge to

a low-carbon future while others see that ready availability of gas will simply result in increasing use of fossil fuel-based energy. As there are divisions even within the British government on these issues we can expect that, in the UK at least, this debate is set to run for some time!

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China Shale Gas and Shale Oil

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Technological innovations in rock characterization, horizontal drilling, and well stimulation (hydraulic fracturing) have transformed shale formations from marginal producers to substantial contributors to the energy supply portfolio. The successful development of shale gas (e.g. Barnett gas play) and shale oil (e.g. Bakken oil play) in the US drove many Chinese companies e.g. PetroChina, Sinopec, CNOOC, Yanchang Petroleum, China Huadian, Henan Provincial Coal Seam Gas Co., etc. and foreign companies e.g. Shell, ExxonMobil, BP, HESS, Chevron, ConocoPhillips, Statoil, Total, etc. to explore the vast China shale resources. In 2010, The Strategic Research Center of Oil and Gas, Ministry of Land and Resources and China University of Geosciences at Beijing used an analog assessment regime to announce that China Shale Gas resource is predicted to be about 30 BCM (1050 TCF). In 2011, the US Energy Information Administration (EIA) assessed that China could have 1275 trillion cubic feet (TCF) technically recoverable shale gas, in March 2012, China Ministry of Land and Resources announced China had 25.08 trillion cubic meters (886 TCF) of recoverable onshore shale gas reserve. Either number indicates China's shale resource can weigh against US's 862 TCF recoverable shale gas resources. Figure 1 illustrates temporal and spatial distribution of the potential major shale gas and shale oil plays spanning from Pre-Cambrain Sinian shale in South China to Quaternary shale in Qaidam Basin.

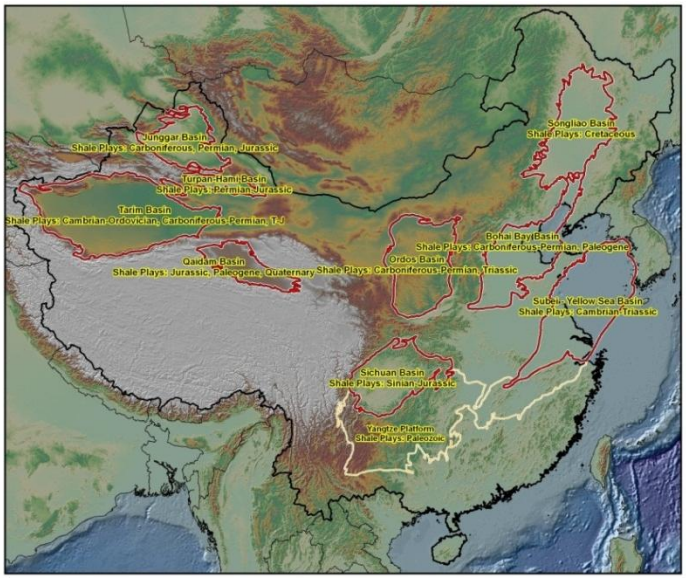

Figure 1 The potential major China shale gas and shale oil plays, the scale is around 800 miles in width

No shales in the world are the same. Hydrocarbon related shales formed in diverse paleo-depositional settings in China distribute in different kinds of basins, these basins underwent different tectonic activities. China has many hydrocarbon producing and potential basins. The hydrocarbons were generated from source rocks deposited marine, lacustrine and transitional (coastal swamp associated with coal) settings, so the gas or oil potential shales in China can be classified into these three types, the typical marine shale, transitional shale and lacustrine shale can be represented by Paleozoic Sichuan Basin, Carboniferous to Permian Ordos Basin and Cenozoic Bohai Bay Basin respectively (Figure 2).

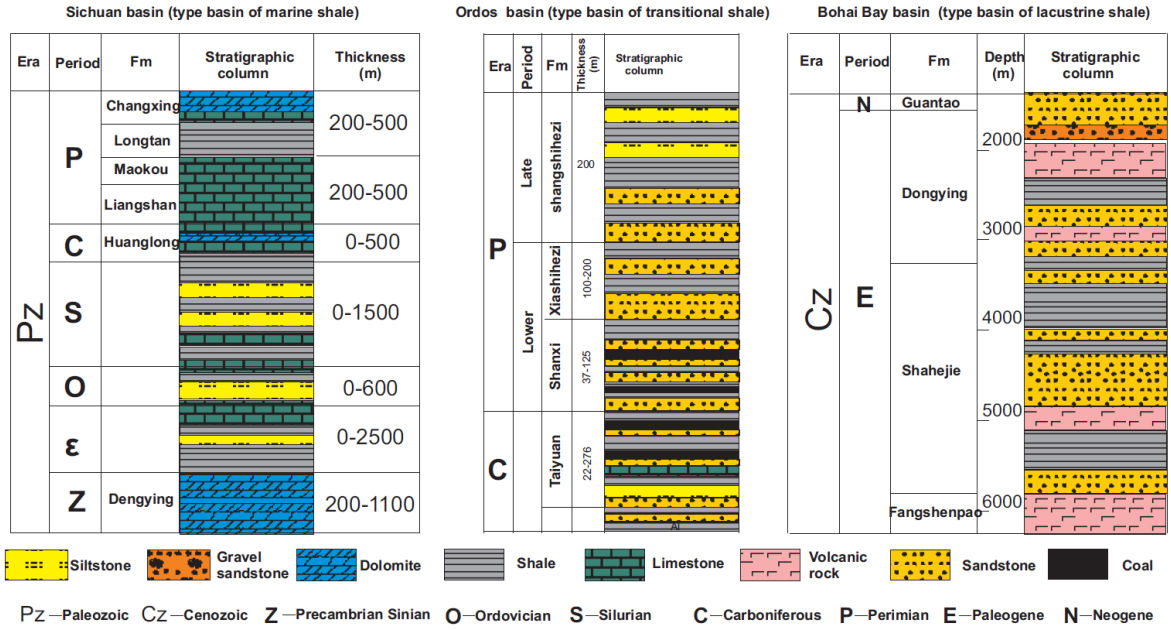

Figure 2 Three kinds of potential shales (marine, lacustrine and transitional/coastal setting) and their type basins

During the Pre-Cambrian Sinian period, 30-300m thick Doushantuo marine shale was mainly distributed in South China in shelf and slope setting, TOC of the Doushantuo shale ranges from 1 to 6% and Ro is around 2.5-4%. The Cambrian Qiongzhusi, Ordovician Wufeng and Silurian Longmaxi marine shales or their equivalent shales were vastly deposited in the ancient passive margin (mainly), cratonic and foreland setting in South China Yangtze platform. These shales are thick (40-500m), widely distributed and have high TOC (1-8%), Ro (1.5-4%), brittle mineral composition (40-60%) and decent portion of intra-organic nano-porosity by using FIB/SEM analysis (Figure 3). Meanwhile, favorable Cambrian and Ordovician shales were mainly deposited in restricted platform to basin setting in Northwest Tarim basin. The thickness for Lower Paleozoic shales in Tarim basin is about 100-800m and the shales have TOC of 0.5-5% and Ro of 0.4-3%. The kerogens in these marine shales are mainly type I and type II. During the Carboniferous and Permian period of marine regression, the shales associated with coal were mainly deposited in transitional (coastal) setting in north China, Tarim basin in Northwest China and Yangtze platform in South China, e.g., the typical transitional shales of Benxi, Taiyuan and Shanxi shales in North China with main gas prone type III kerogen in North China have high TOC of 2-20% and variable Ro of 0.6-2.5%. Since the late Triassic, the organic rich shales are dominated by pro-delta shales in lacustrine setting, e.g., the Triassic Yangchang shale in Ordos basin in North China, Triassic to Jurassic shales in Tarim basin, Jurrassic Badaowan and Xishanyao shales in Junggar and Turpan-Hami basins in Northwest China, Jurrassic Ziliujing shales in Sichuan basin in Southwest China, Cretaceous Qingshankou and Nenjiang shales in Songliao Basin, Cenozoic shales in East China (e.g. Shahejie shale in Bohai Bay basin, Hetaoyuan shale in Nanxiang basin, Xingouzui and Qianjiang shales in Jianghan basin), Quaternary shale in Qaidam basin in Northwest China, etc. They are mainly featured by type I and type II kerogen, low maturity (typically <1.2%) and high TOC (up to 30%).

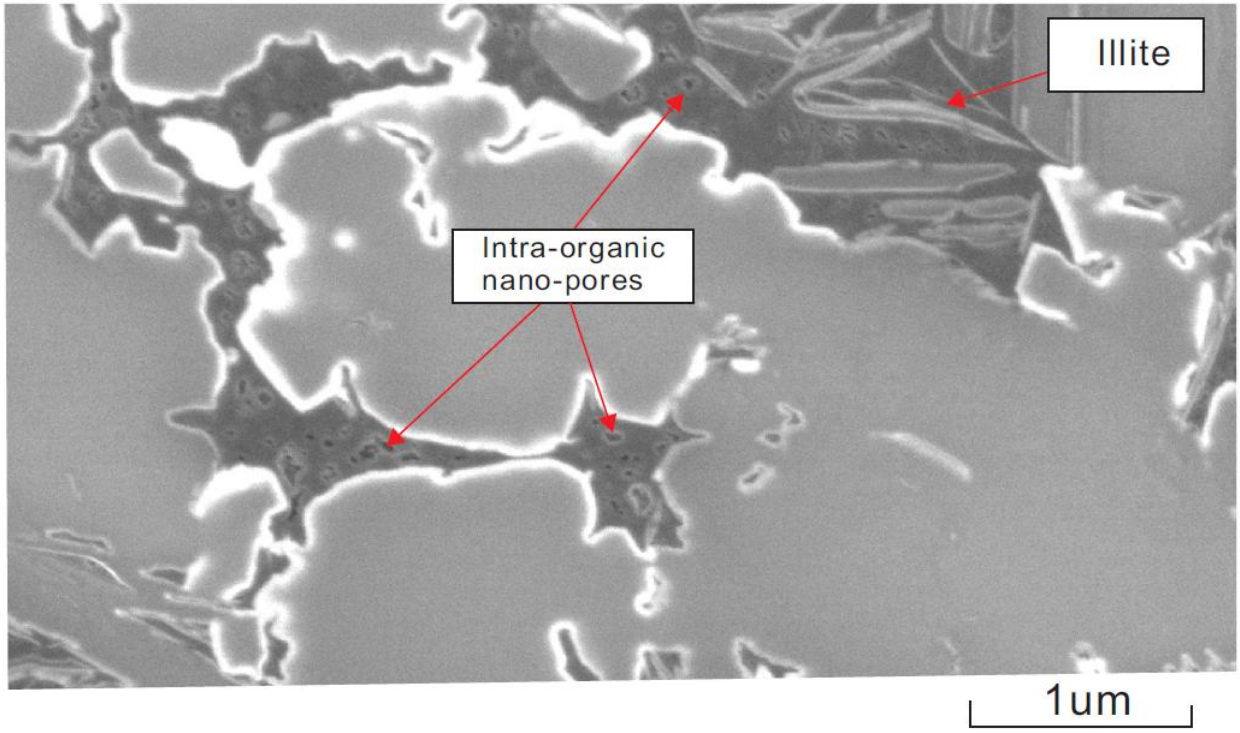

Figure 3 FIB/SEM slice showing intra-organic nano-pores of Silurian shale in East Sichuan Basin

These above-mentioned shales have been known for their potential as source rocks for hydrocarbons that migrated into other formations, but have not been considered as in-situ gas reservoirs before. These shales in the three depositional settings represent the primary potential shale plays in China as showed in

figure 1. The Paleozoic deep buried marine shales with high TOC and Ro are emerging thermogenic shale gas plays and the Meso-Cenozoic medium buried lacustrine shales with very high TOC and medium or low Ro are emerging shale gas or shale oil plays respectively, while the shallow Quaternary organic rich lacustrine shales are usually biogenic shale gas plays. Also, when compared with Europe, most potential shale plays in China are located in thinly-populated areas. When compared with US producing shales, the shales in China spanned longer time period from Pre-Cambrian, the Paleozoic potential marine shales in China have higher maturity; also there are more potential lacustrine shales with low maturity and oil producing potential in China (Table 1).

Table.1 Comparison of properties between typical potential shales in China and US

Basin	Formation	Age	TOC (%)	Ro (%)	Thickness(m)
Qaidam	Qigequan	Quaternary	0.3-0.6	0.2-0.5	0-800
Baohai Bay	Shahejie 3	Paleogene	0.3-33	0.3-1	230-1800
Songliao	Qing and Nenjiang	Cretaceous	0.5-10	0.7-1.3	>100
Songliao	Shahezi	Cretaceous	0.7-1.5	1.5-3.9	100-350
Turpan-Hami	Shuixigou	Mid and Early Jurassic	1.3-20	0.4-1.1	50-600
Junggar	Xishanyao	Mid Jurassic	0.2-6.4	0.6-2.5	350-400
Sichuan	Ziliujing	Jurassic	0.2-2.4	0.8-1.6	40-240
Ordos	Yanchang	Trassic	0.6-5.8	0.7-1.1	50-120
Ordos	Shanxi	Carboniferous-Permian	2.0-20.0	0.6-2.5	50-180
Sichuan	Xujiagou	Late Triassic	1.0-4.5	1-2.2	150-1000
Yangtze(including Sichuan)	Longtan	Late Permian	0.4-22	0.8-3	20-2000
Yangtze(including Sichuan)	Longmaxi	Early Silurian	0.5-3	2.0-3.0	30-100
Yangtze(including Sichuan)	Qiongzhusi	E Cambrian	1.0-8.0	1.5-4.0	40-500
Tarim		Cambrian,Ordovician	0.5-5	0.4-3	100-800
Fort Worth	Barnett	Mississippian	2.0-5.0	1.1-1.4	60-90
Appalachian	Marcellus	Devonian	2.0-6.0	0.6-1.9	90-600

So far, there is still no real commercial production of shale gas and shale oil. But Chinese have been working on the regional shale gas assessment for almost all the current conventional producing basins and other marginal basins and platforms. The current most studied areas include Sichuan Basin and its surrounding margin, Ordos Basin, East Liaohe Sub-basin, Bohai Bay Basin, Yangtze platform. A lot of drilling activities in these areas for both marine and lacustrine shales have been conducted (Figure 4). PetroChina picked Weiyuan, Changning, Zhaotong and Fushun-Yongchuan blocks in Southern Sichuan, Northern Yunan and Guizhou areas.. More than 10 wells have been drilled and one well was horizontally fraced. The so called “commercial gas flow” were reported from 7 wells, e.g., Yang101 (joint well of Shell and PetroChina) was reported to tap shale gas with output of 60,000 cubic meters/day (2,118,880 cubic feet/day). Sinopec has drilled more than 10 wells in Southeast Guizhou, Southeast Chongqing, West Hubei, Northeast Sichuan, Jianhan basin in Hubei and South Anhui areas. 6 wells were reported to encounter the “commercial gas or oil”. For example, Sinopec was reported to tap the Jurassic Ziliujing lacustrine shale gas in East Sichuan Basin and Daanzhai lacustrine shale gas in Yuanba area in NE Sichuan Basin, and shale oil from Tertiary Bohai Bay Basin and Nanxiang Basin. One well was horizontal well and hydraulicly

fractured in the horizontal lateral. The Pengshui, Jiannan and Huangping blocks were already selected as favorable areas. CNOOC conducted preliminary work on shale gas in Anhui and Zhejiang provinces. Yanchang Petroleum made discoveries in 5 wells from Yanchang 7 hot shale of Triassic lacustrine setting in Yan'an area of Ordos basin. So far, China has succeeded in carrying out hydraulic fracturing on vertical shale gas wells and has been starting to drill and frac horizontal wells.

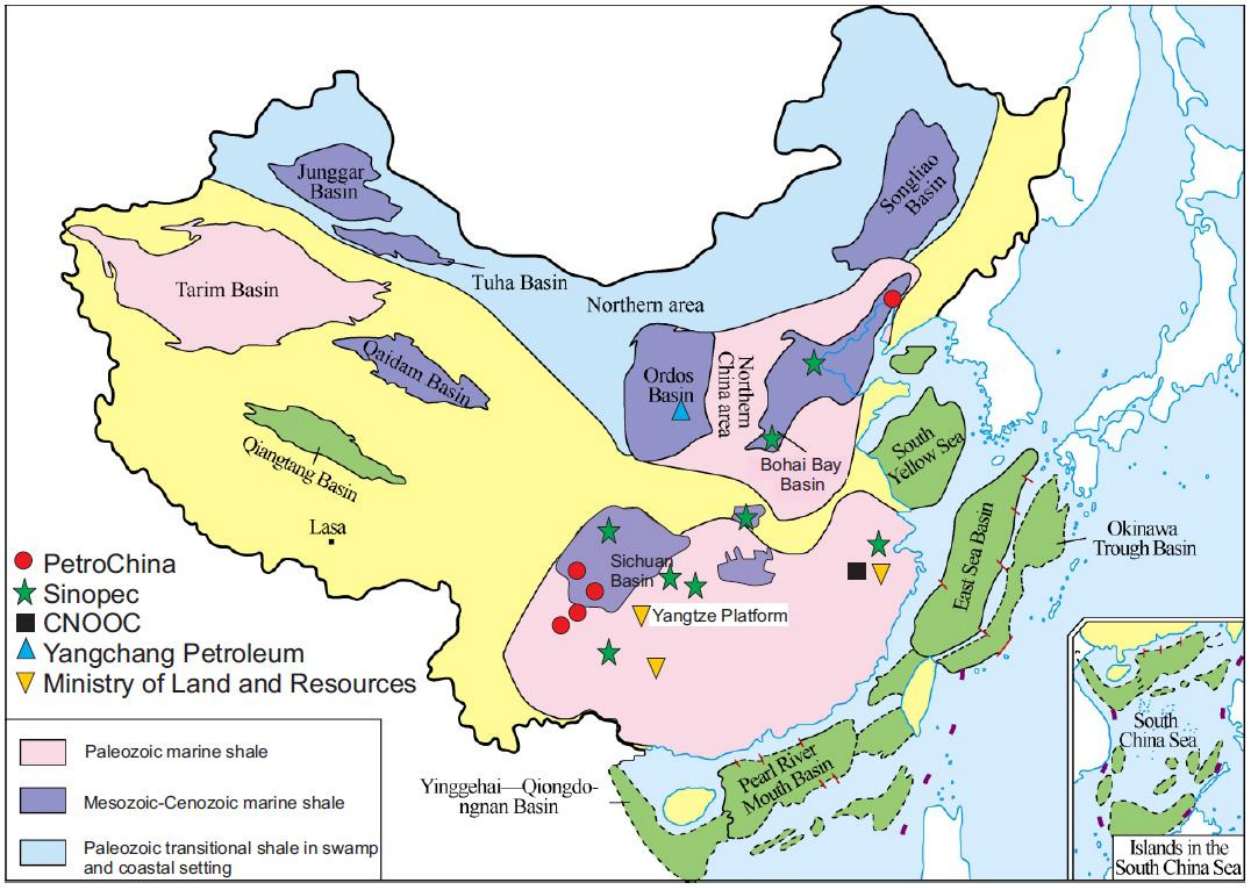

Figure 4 Major drilling activities in potential China shale plays (the base map of paleo-environment courtesy of Caineng Zou, PetroChina)

Since good gas shows from some wells drilled by Shell in Fushun-Yongchuan block, Shell signed first production-sharing contract with PetroChina in China. This first landmark contract, historical and recent drilling and huge shale gas reserve potential demonstrated that China will probably meet its scheduled plans that real commercial shale gas production will start from 2015 and the goal of production capability from shale gas fields will reach 60-100 bcm/y (2120-3533 bcf/y) in China by 2020. This will be fulfilled not only through borrowing US experiences and China's technology advancement, but also by adopting stimulus policies, e.g, China's Ministry of Land and Resources (MLR) recently list shale gas as an independent mineral resource, which will encourage more companies to have the qualification to invest in and exploit shale resources to boost the commercial production.

Valuable links

Maps

- Active Shale Gas Plays, lower 48 http://www.eia.gov/oil_gas/rpd/shale_gas.pdf
- Various shale gas plays (Barnett, Fayetteville, Haynesville-Bossier, Marcellus, Woodford) and shale oil (Bakken). http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm

Assessments

- Assessments of undiscovered oil and gas resources, onshore US http://energy.cr.usgs.gov/oilgas/noga/
- Assessments of undiscovered oil and gas resources, World http://certmapper.cr.usgs.gov/rooms/we/index.jsp
- Assessment of Australian energy resources https://www.ga.gov.au/image_cache/GA17412.pdf (courtesy of Gesocience Australia)

Consortia

- Core Lab "Reservoir characterization and production properties of gas shales" (http://www.corelab.com/rm/irs/studies/GasShales_Global.aspx);
- "Haynesville and Bossier Shale Evaluation" (http://www.corelab.com/rm/irs/studies/Haynesville-Bossier.aspx);
- "Eagle Ford Shale Study"(http://www.corelab.com/rm/irs/studies/EagleFord.aspx);
- "Montney Shale Regional Study"(http://www.corelab.com/rm/irs/studies/MontneyShale.aspx);
- "Global Gas Shales Study" (http://www.corelab.com/rm/irs/studies/GasShales_Global.aspx)
- Colorado School of Mines FAST (Fracturing, Acidizing, Stimulation Technology) Consortium Project 9: stimulation of "shale" reservoirs (http://www.mines.edu/fast/).
- Humble Geochemical Services (http://www.humble-inc.com/) http://www.humble-inc.com/PlayTypes/ShaleGas/tabid/102/Default.aspx
- GeoMark Research
- Appalachian Basin Shale Gas Study (2005) (http://www.geomarkresearch.com/studies_northamerica.cfm)
- Baseline Resolution (http://brilabs.com/)
- Geochemistry Studies (http://brilabs.com/contents/basin_studies2.htm)
- GASH (Gas Shales in Europe)
  - (http://www.gfz-potsdam.de/portal/-;jsessionid=7BA522526C3C6B6F7C57E0E6A3579326?$part=binary-content&id=2022464&status=300&language=en)
- GeoEn (Germany) http://www.geoen.de/index.php/shale-gas.html
- CSIRO Shale Research Centre (http://www.csiro.au/science/shaleResearchCentre.html)
- PTTC Unconventional Tech Center http://www.pttc.org/tech_centers/unconventional_resources.htm)

Additional Sources of Information

- **References** (see gas shale bibliography on Gas Shale Committee web site) (http://emd.aapg.org/members_only/gas_shales/gasshalereferences.pdf)
- **Trade Journals** (articles included in bibliography above)
    - Powell Barnett Shale Newsletter (http://www.barnettshalenews.com/)
    - American Oil and Gas Reporter (http://www.aogr.com/)
    - Oil and Gas Investor (http://www.oilandgasinvestor.com/)
    - Oil and Gas Journal (http://www.ogj.com/index.html)
    - Hart's E & P (http://www.epmag.com/)
    - AAPG Explorer (http://www.aapg.org/explorer/)
- **Subscription Services**
    - Hart Unconventional Natural Gas Report (http://www.ugcenter.com/)
    - IHS Energy (http://energy.ihs.com/)
    - Warlick International Report (http://warlickenergy.com/)
- **Hydraulic Fracturing**
    - http://www.strongerinc.org/

Gas Shales and Shale Oil Calendar

April 16-17, 2012: International Symposium on Shale Oil Technologies, Wuxi, China. Petroleum Geology Subcommittee of Chinese Geological Society.

April 17-18, 2012: RPSEA Unconventional Gas Conference 2012: Geology, the Environment, Hydraulic Fracturing, Canonsburg, PA http://www.rpsea.org/en/cev/408

April 22-25, 2012: AAPG-Annual Convention and Exhibition, Long Beach, CA (sessions on shales and other unconventional plays) http://www.aapg.org/longbeach2012/

April 23-25, 2012: Unconventional: the New Standard, Developing Unconventional Gas (DUG), Fort Worth, TX. http://www.dugconference.com/

May 14-16, 2012: 3rd Annual Developing Unconventional Oil Conference & Exhibition, Denver, CO http://www.hartduo.com

May 14-16, 2012: GeoShale 2012: Recent Advances in Geology of Fine Grained Sediments, International Scientific Conference, Warsaw, Poland. http://www.geoshale.com

August 22-23, 2012: Shale Energy Technology Conference, World Oil, Houston, TX. http://www.gulfpub.com/ShaleEnergyConference

September 30-October 3, 2012: AAPG-International Convention and Exhibition, Singapore (sessions on shales and other unconventional plays are likely) http://www.aapg.org/singapore2012//

October 14-16, 2012: 3rd Annual Developing Unconventional Gas Eagle Ford Conference & Exhibition, San Antonio, TX http://www.dugeagleford.com/

November 13-15, 2011: 4th Annual Developing Unconventional Gas (DUG) East Conference & Exhibition, Pittsburgh, PA http://www.dugeast.com

2013

April 16-18, 2012: 7th Annual Developing Unconventional Gas Conference & Exhibition, Fort Worth, TX http://www.dugconference.com/

April 16-17, 2012: International Symposium on Shale Oil Technologies, Wuxi, China. Petroleum Geology Subcommittee of Chinese Geological Society.

April 22-25, 2012: AAPG-Annual Convention and Exhibition, Long Beach, CA (sessions on shales and other unconventional plays) http://www.aapg.org/longbeach2012/

May 14-16, 2012: 3rd Annual Developing Unconventional Oil Conference & Exhibition, Denver, CO http://www.hartduo.com

August 12-14, 2013: Unconventional Resources Technology Conference, SPE, AAPG, and SEG, Denver, CO. http://www.urtec.org/

September 30-October 3, 2012: AAPG-International Convention and Exhibition, Singapore (sessions on shales and other unconventional plays are likely) http://www.aapg.org/singapore2012//

October 14-16, 2012: 3rd Annual Developing Unconventional Gas Eagle Ford Conference & Exhibition, San Antonio, TX http://www.dugeagleford.com/