EMD Gas Shales Committee Mid-Year Report, FY 2012

Neil S. Fishman, Chair

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INTRODUCTION

It is a pleasure to present this Mid-Year Report from the EMD Gas Shales 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. New in this report is a section on the Niobrara Formation, an entire section on China, and an expanded section on

Europe. The inclusion in this report of shales from which any hydrocarbon is produced reflects the expanded mission of the EMD Gas Shales 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 Gas Shales 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@usgs.gov) 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 almost 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 July, 2011 is approximately 11,455 with about 9,569 still online.

Total cumulative gas production reached 3.032 TCF by the end of July, 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 791 separate projects at the end of July, 2011. Cumulative production for the first 7 months of 2011 was 66,053,544 MCF of gas. That was a 5.6% decline from the first 7 months of 2010.

There were 30 operators with production at the end of July, 2011. There were 9,569 wells online at the end of July, 2011. There were 111 new wells drilled in 2009, and only 58 in 2010 and approximately 30 in the first 7 months of 2011. That is a 48% decrease in active wells from 2009 to 2010 and continuing drop in new wells completed in 2011. Most of the production comes from a few operators. The top 10 operators produced 82.3% 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 July, 2011 was 32 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/BBL and at the end of July, 2011 the ratio was 1.61 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 CO2 in the produced gas; however, the percentage of CO2 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://wsh060.westhills.wmich.edu/MGRRE/index.shtml

Top 10 Operators:

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

Significant Trends – Production continues to decline as are the total number of active wells which show a decline for the first time. Daily gas production per well slightly declined by 3.9% in the first 7 months of 2011. However, daily water production per well decreased 7.8% in the first 7 months of 2011 compared to the same period in 2010. The number of horizontal completions is increasing, but still represents 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

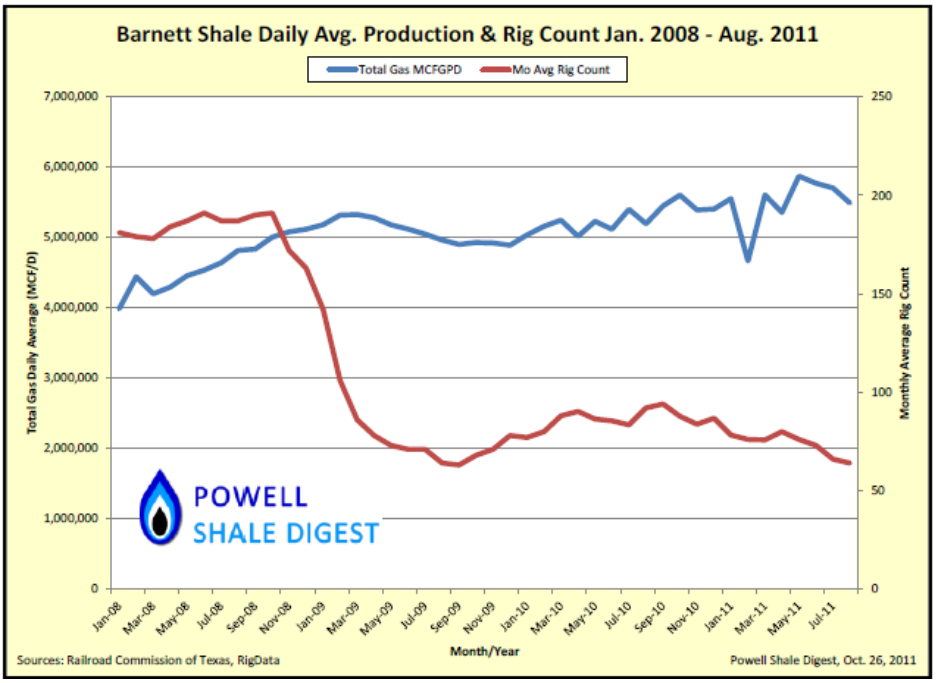
Sheet 1 - Stephan H. Nordeng and LeFever, J.A., 2010, Structural Transect of the Sanish and Parshall Fields, Bakken Formation, Mountrail County, North Dakota

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)

As noted in the Powell Shale Digest (www.shaledigest.com) Barnett gas production is holding steady at 5.5 BCF/D even with the steady drop in the rig count in the play. 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).



(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.

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

By Kent Bowker (Bowker Petroleum, LLC)

NORTHERN SHELF, BLACK WARRIOR BASIN, ALABAMA:

GeoMet's Chattanooga Shale program (they called it the Garden City Project) in Blount and Cullman counties in north-central Alabama (north shallow shelf of the Black Warrior Basin) appears to be abandoned. In April, 2011, in their corporate presentation, GeoMet stated that they planned to return the two horizontal wells they had previously had on production back to sales; but state production records indicate that these wells are still shut in.

CHATTANOOGA SHALE, NORTH-CENTRAL TENNESSEE (Appalachian Basin):

After being "excited" by initial results from their Chattanooga Shale program in Tennessee, CONSOL Energy (formally CNX Gas) has de-emphasized their position in the play in recent analyst presentations and press releases. CONSOL appears to have abandoned this project.

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

The Cretaceous (Cenomanian-Turonian) Eagle Ford Group, Gulf Coast Basin, comprises the Eagle Ford Shale and the updip Woodbine Formation in Texas and the updip Tuscaloosa Formation in Louisiana. The Eagle Ford Shale in southwestern Texas has been the target of several operators in the last two years. For many years considered only as the source for oil in Austin Chalk and updip Woodbine and Tuscaloosa clastic reservoirs, the Eagle Ford is now of widespread interest as a self-sourced and -reservoired shale gas and shale oil play. The Eagle Ford Shale trends across Texas from the Mexican border in South Texas east into East Texas and Louisiana, an area roughly 50 miles wide and 400 miles long. The Eagle Ford also produces condensate along the SW-NE trend of the current play that sits astride and just updip the general trend of the underlying Lower Cretaceous carbonate shelf edge.

The first of the Eagle Ford gas wells was drilled in 2008, and it flowed at a rate of 7.6 MCFG per day from a 3,200 foot lateral (first perforation 11,141 feet total vertical depth) with 10 frac stages. The wells that have been completed have initial potential similar to that of the discovery well; they then display a rapid decline in production similar to those in other shale plays. A total of 64 BCF of gas was produced from the Eagle Ford during 2010 (http://www.rrc.state.tx.us/eagleford/eaglefordproduction.pdf, accessed March 23, 2011). As for shale oil wells, recently-drilled wells have shown initial production rates of several hundreds of BOPD, and between Jaunary 2009 and October 2010, more than 2.5 MMBO was produced from the Eagle Ford in 2010 (Railroad Commission of Texas, http://www.rrc.state.tx.us/eagleford/eagleford-oilproduction.pdf, accessed March, 2011). For the year 2010, there were 1,229 permitted

(http://www.rrc.state.tx.us/eagleford/eagleford_dp_issued_08-10.pdf, accessed March 23, 2011). In February, 2011, the number of permitted wells had increased to 1,132 (Railroad Commission of Texas, http://www.rrc.state.tx.us/eagleford/images/EagleFordShalePlay201102-large.jpg). 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, with as much as 70% calcite and lesser amounts of quartz; clay content is relatively low (Durham, 2010). 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. The average well cost is between $5 million to $6 million dollars (Railroad Commission of Texas, http://www.rrc.state.tx.us/eagleford/index.php, accessed July, 2010). The current area of primary interest is where the Eagle Ford is in the oil window, or the wet gas window, due to market return on liquid commodities. In the future, extensive development of the Eagle Ford in the gas window will be dependant on increased gas market prices. For more information on Eagle Ford production, please refer to the Texas Railroad Commission web link at http://www.rrc.state.tx.us/eagleford/.

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 July 2011 has totaled 2,209,419,656 mcf from 3,540 wells. For the first seven months of 2011, gas sale totals 530,795,103 mcf from the Fayetteville Shale. Annual gas production from the Fayetteville Shale for 2010 is 775,527,728 mcf from 2,950 producing wells, about a 50% increase compared with 2009 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. As of September 2011, there are a total of 3,488 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 2009 to 2010 averaged 4,720 feet in lateral length with some wells up to 7,000 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.

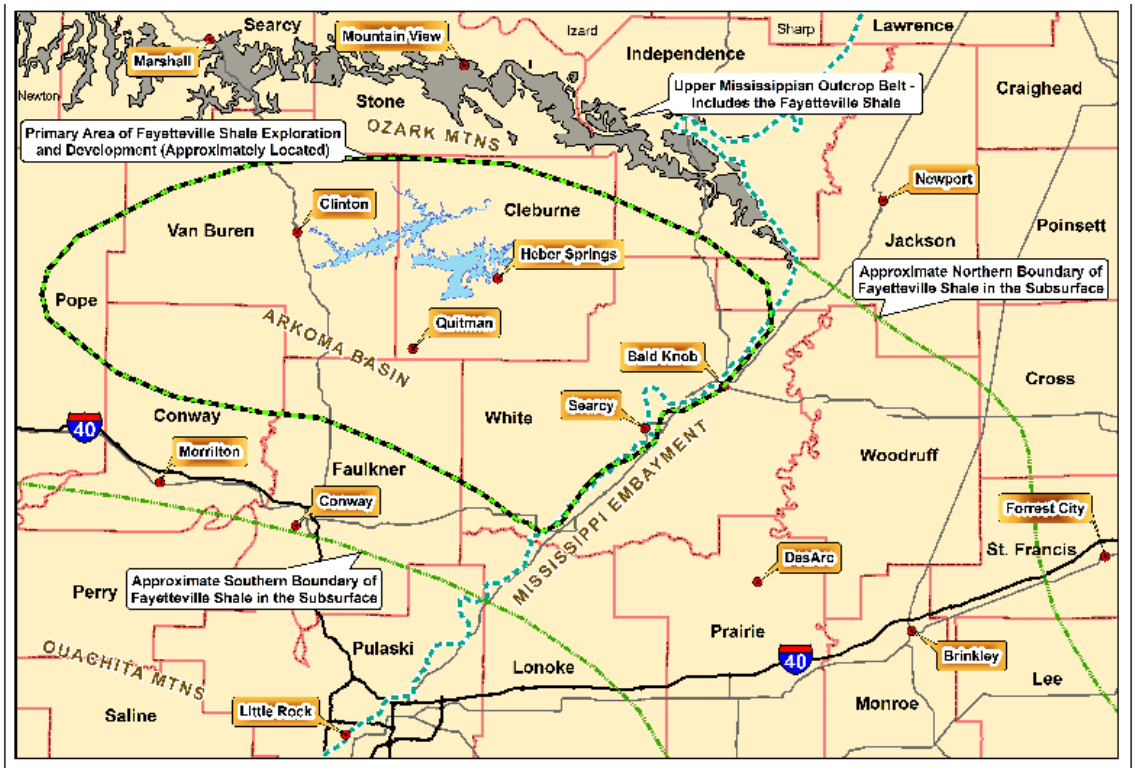


Figure 1. Primary area of the Fayetteville Shale exploration and development in Arkansas.

The top three operators of the Fayetteville gas shale play as of September 2011 based on numbers of producing wells are as follows (Figure 2):

1) Seeco Inc. (an exploration subsidiary of Southwestern Energy) (2121 wells)

2) BHP Billiton Petroleum (767 wells)
3) XTO Energy, Inc. (a subsidiary of ExxonMobil) (585 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.

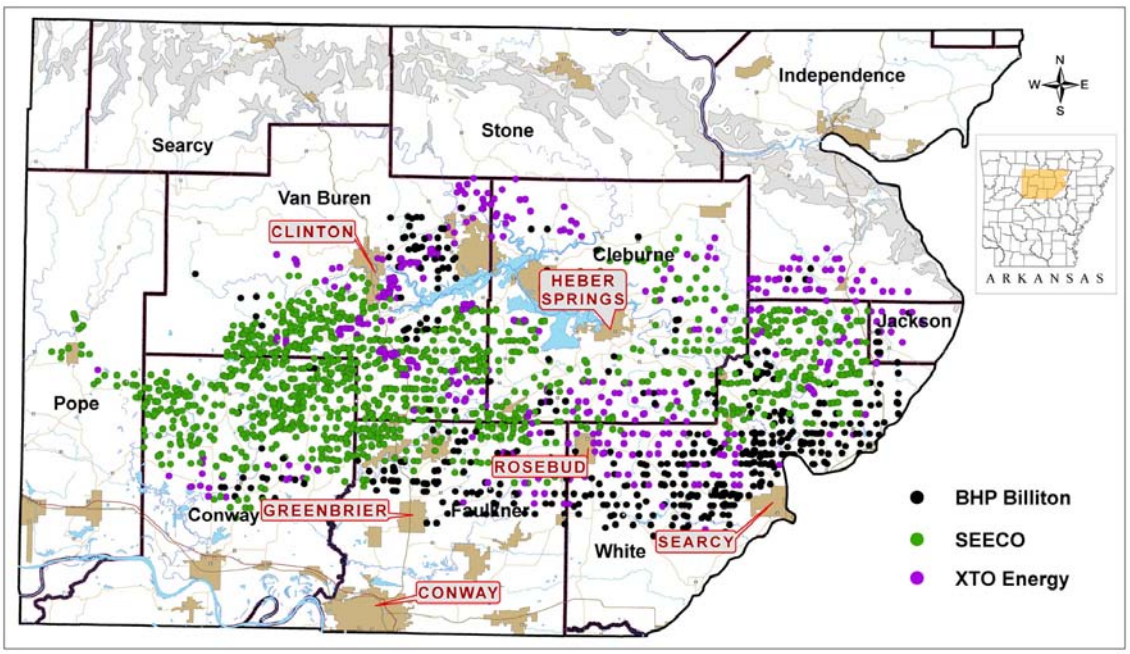


Figure 2. Location map of the Fayetteville Shale producing wells by top 3 operators as of September 2011.

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. AOGC imposed a six-month moratorium on new injection wells in the area and this regulation took effect in January 2011 to allow time 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, 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 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. On the March hearing, AOGC ordered the

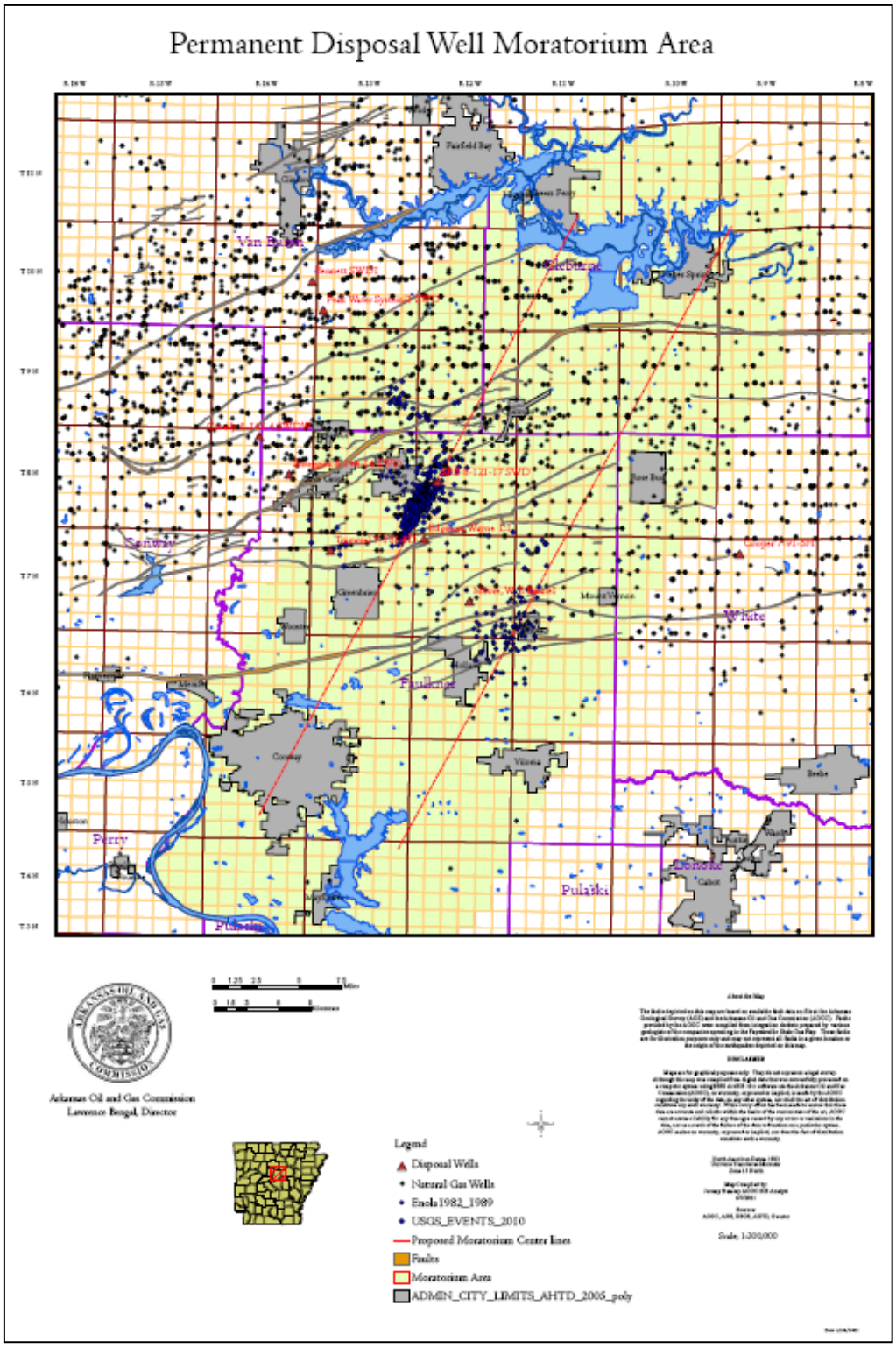


Figure 3. Moratorium area for the permanent disposal wells in the Fayetteville Shale Play, Arkansas (from the AOGC website).

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. 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.

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

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

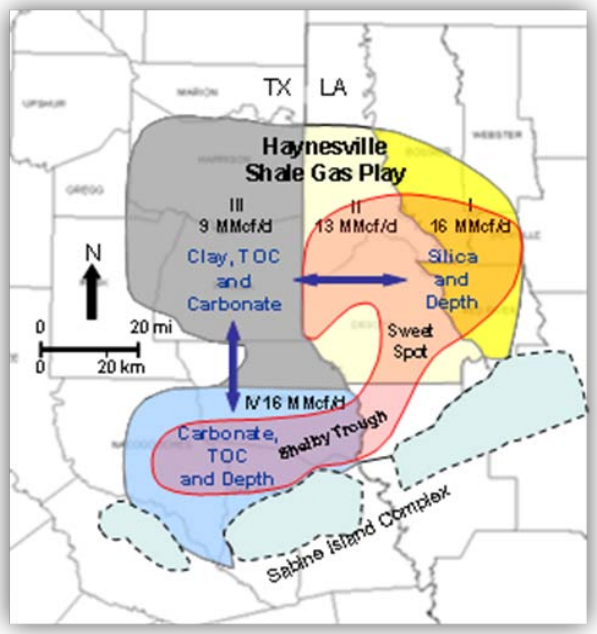
by Ursula Hammes (Bureau of Economic Geology, Austin, TX)

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, in press). 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).

This last quarter the Haynesville Shale production surpassed Bossier production with estimated production rate of 5.8 BCF/D from about 1700 wells and cumulative production of close to 200 BCF (Figs. 2 and 3). The reservoir pressure is at about 10,000 psi, with geopressured gradients ranging from 0.7 to 0.95 psi/ft resulting in steeper decline curve (approximately 80% in the first year) than other shale-gas plays. The high pressure gradient increases porosity, permeability, and free-gas content while reducing effective stress. As a result of high reservoir pressure, free-gas content is doubly increased through increases in porosity and gas density (Wang et al., in review). Several companies operating in the Haynesville have been choking back new wells in an attempt to preserve fracture conductivity and reservoir permeability. This results in lower initial gas rates, but could translate into significantly higher ultimate recoveries per well if the technique proves successful over the long term. The optimal range of choke size is from 14 to 22/64" and the optimal range of frac stage is from 12 to 16. Initial potential and production are higher in silica-rich Red River, Bienville, and Bossier Parishes in Louisiana than they are in clay-rich Harrison and Panola Counties in Texas (Fig. 1). Drilling and completion costs range from $6-9 million per well and includes 12-15 frac stages stimulated with slickwater and either ceramic or resin-coated proppant. Additional information on the aynesville can be found at the Louisiana Oil and Gas Association (http://www.loga.la/haynesville-shale-news/, accessed November 3, 2011.

A



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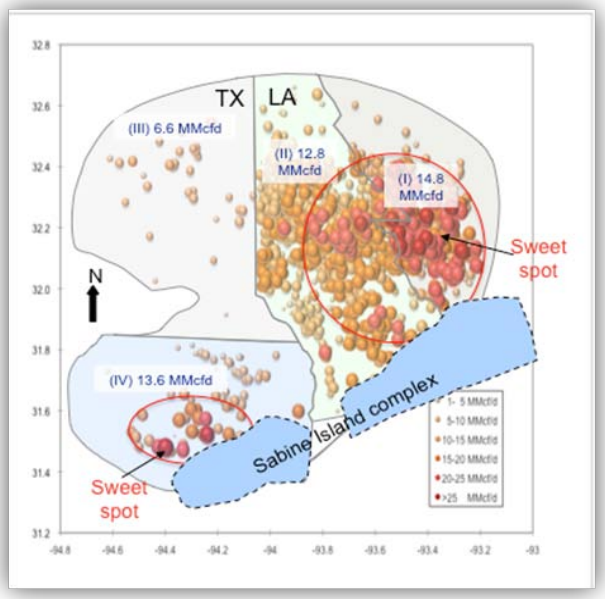

Figure 1. A) Initial potentials of four production areas and factors (mineralogy) affecting initial potential in the core area of the Haynesville play. B. Bubble map of initial potential for Haynesville wells. TX = Texas, LA = Louisiana. From Wang and Hammes (2010) and Wang et al. (in review).

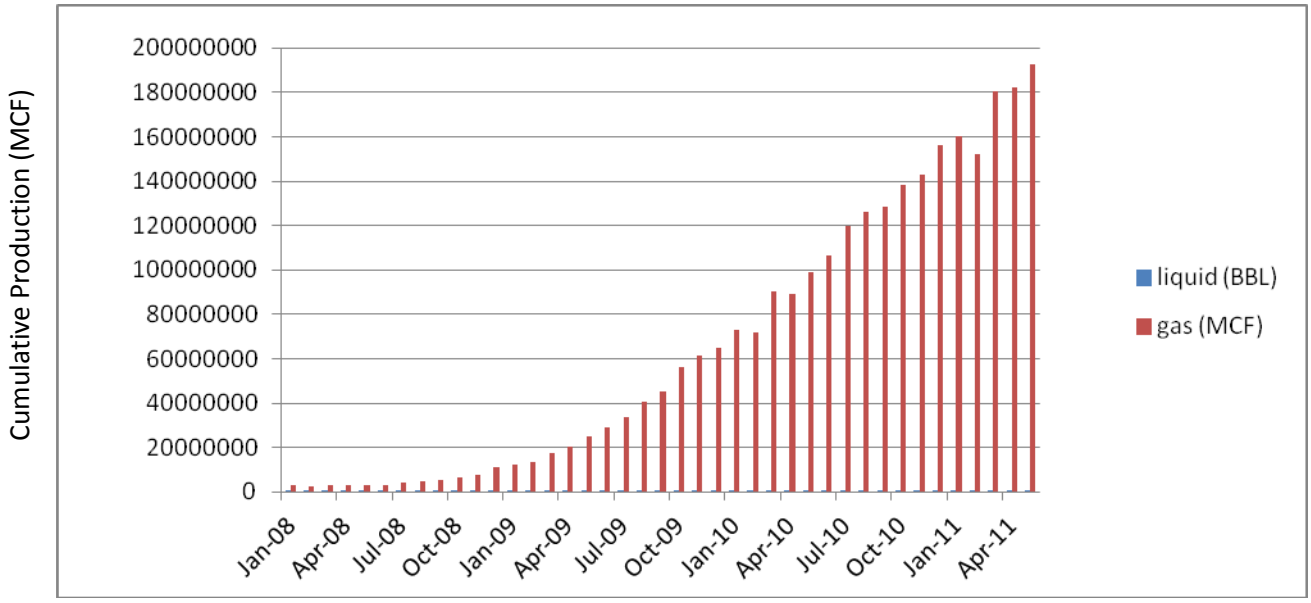

Figure 2: Cumulative production chart (MCF) for Haynesville Shale (data from IHS Enerdeq).

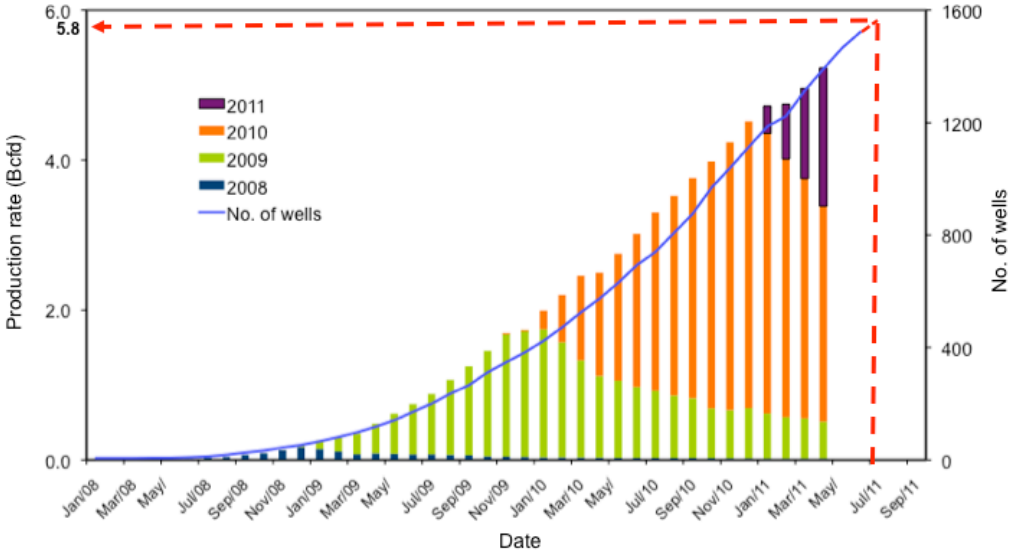

Figure 3: Well completion and daily production gas rate from the Haynesville Shale based on data from the IHS database.

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NEW ALBANY AND MAQUIKETA SHALES: Illinois Basin

By Rick Sumner (Countrymark Energy Resources, LLC)

Maquoketa Shale:

There were no wells permitted for the Maquoketa Shale in 2011 in Indiana, Illinois or Kentucky.

New Albany Shale

New Albany Shale activity in the Illinois Basin has been very slim in 2011. 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, according to the Energy Information Administration (EIA), is the most areally extensive shale play in the U.S., covering 95,000 square miles (http://www.eia.gov/oil_gas/rpd/shale_gas.pdf). The EIA also shows the gross thickness of the Marcellus

Shale increases to the northeast, with the thickest area located in northeastern Pennsylvania (http://www.eia.gov/oil_gas/rpd/shaleusa5.pdf). 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 (Cardott and others, 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, 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). Horizontal drilling and induced fractures provide the porosity and permeability which allow for commercial production of natural gas from this formation. "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 water and used hydraulic fracturing water, called "flow-back" water, are being addressed with a variety of approaches including recycling and reuse of hydraulic fracturing water.

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 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 just a regional source rock. Technological improvements resulted in commercially viable gas production and rapid development of a new play in the Appalachian Basin, the oldest producing petroleum province in the United States. 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 (Coleman, J. L, personal communication, 2011). Pennsylvania has continued to be the state with the most drilling into and production from the Marcellus Shale.

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. Figure 1 shows the distribution of three assessment units (AU) defined in this latest assessment. Ninety-six percent of the estimated resource resides in the Interior Marcellus AU.

Maryland: There were no wells drilled for the Marcellus Shale between 2004 and 2010. 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 the department of Natural Resources (DNR) to undertake a study of drilling for natural gas in the Marcellus Shale in western Maryland. Recommendations for best practices will be submitted by August 1, 2012, and a final report with findings 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 in 2010 was 34 million cubic feet (mmcf), down from the 56.1 mmcf of gas reported for 2009. There was no reported oil production. Between 2005 and 2010, 23 wells were drilled targeting the Marcellus Shale, all of which were vertical wells. These wells were drilled by Talisman Energy, EOG Resources, Quest Eastern Resource, Eastern American Energy, Chesapeake Appalachia, Petroleum Development Corp., Norse Energy Corp, U.S. Energy Development, Fortuna Energy, Mesa Energy, and MegaEnergy Operating.

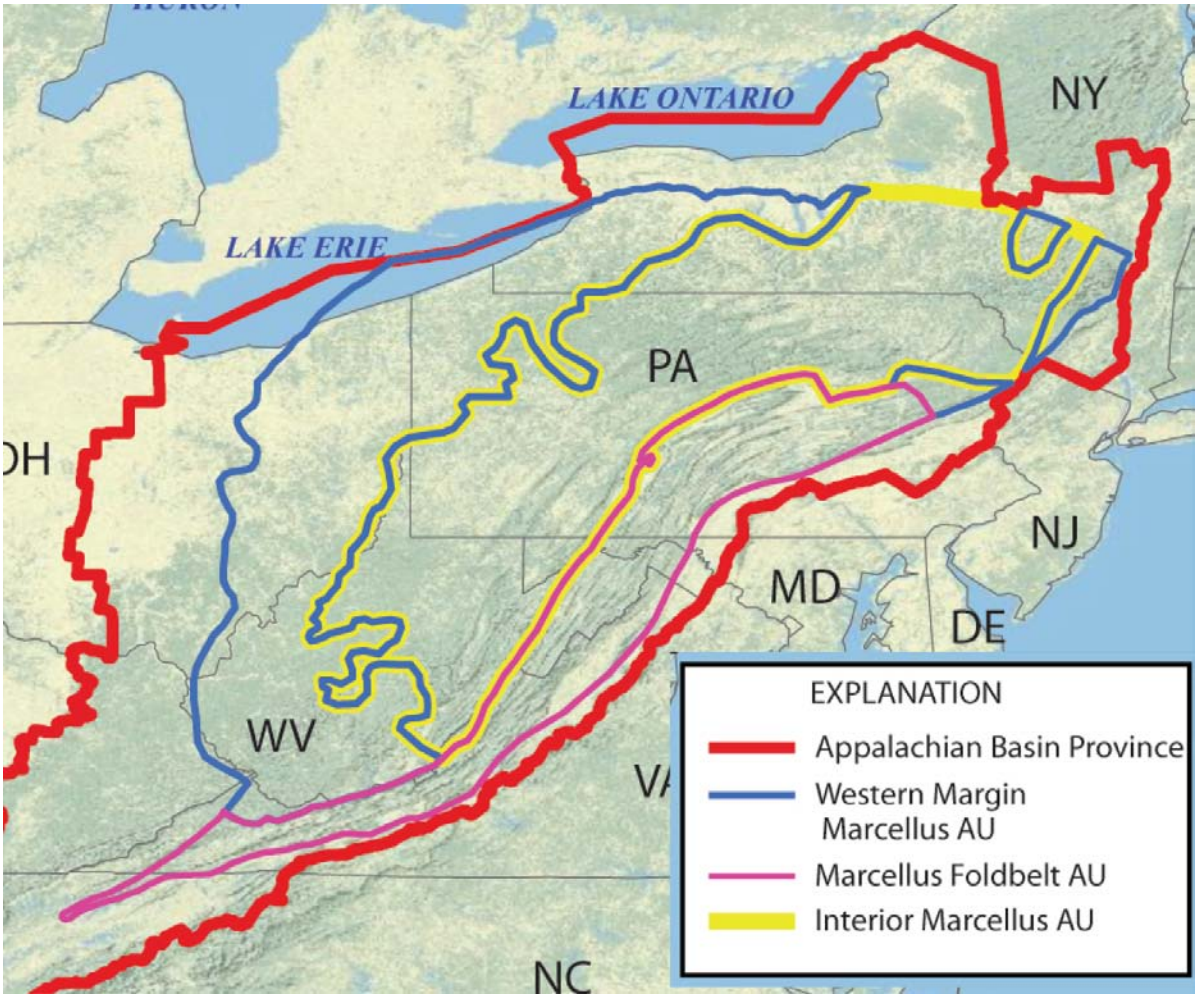

Figure 1. 2011 Marcellus Shale Assessment Units (modified from Coleman and others, 2011).

The NY Department of Environmental Conservation (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 will be extended until December 12, 2011. In the meantime, there is essentially a moratorium on horizontal drilling and high-volume hydraulic fracturing of the Marcellus Shale and other low permeability reservoirs in New York.

Ohio: The Ohio Department of Natural Resources reported that almost 727.8 mmcf of gas, about 8,800 barrels of oil, and about 121,800 barrels of water were produced from the Marcellus Shale between 2006 and 2010. In 2010, there were 28 wells producing from the Marcellus Shale in Monroe, Noble, Washington, Belmont, Jefferson, and Carroll counties. As of October, 2011, 6 horizontal wells were drilled in the Marcellus.

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. Additionally, the Ohio Division of Mineral Resources Management (DMRM) regulates the disposal of brine and other wastes produced from the drilling, stimulation, and production of oil and natural gas.

Pennsylvania: The deepest depth to the base of the Marcellus Shale is in east-central Pennsylvania, and the deepest wells have been drilled to 8,500 feet to test the Marcellus in Clinton County. The areas of greatest activity are in southwestern and northeastern PA.

Between July, 2010, and June, 2011, almost 707 BCF of gas, over 516,000 barrels of condensate, and about 404,800 barrels of oil were produced from the Marcellus Shale. Of the 1642 active wells as of June, 2011, 1089 were horizontal wells. Between January and June, 2011, Chesapeake Appalachia was the largest producer of natural gas with almost 81 BCF production, followed by Talisman Energy USA, Cabot Oil & Gas, Range Resources Appalachia, EQT Production, SWEPI LP, Seneca Resources Corporation, and Anadarko E&P Co. in descending order, each with production over 15 BCF of natural gas in the latest 6-month reporting period.

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, Tioga, Bradford, and Susquehanna.

Virginia: There were no wells drilled for the Marcellus Shale between 2004 and 2010. There is 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 focus of a 2-day field trip after the American Association of Petroleum Geologists Eastern Section meeting in Arlington, Virginia, in September, 2011.

The U.S. National Forest Service (NFS) issued the Draft Environmental Impact Statement (DEIS) and Draft Revised Land and Resource Management Plan for the George Washington National Forest (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. The Final EIS and Land and Resource Management Plan for the GWNF is scheduled to be issued in winter, 2012.

West Virginia: As of October, 2011, 1421 wells were completed in the Marcellus Shale, according to the West Virginia Department of Environmental Protection, and West Virginia Geological and Economic Survey. Production of about 4.75 BCF in 2006, almost 10.3 BCF in 2007, almost 19.5 BCF in 2008, and about 30.5 BCF in 2009 can be attributed to wells with Marcellus Shale reported as at least one of the pay zones. Total production from 1421 wells completed in the Marcellus from 2005 to 2009 was about 65.9 BCF of gas, and over 173,000 barrels of oil. Approximately 350 wells list only the Marcellus Shale as the pay zone, and may represent the number of horizontal wells completed in the Marcellus. Based on volume, the major producers include Chesapeake Appalachia, Equitable Production Company, Cabot Oil & Gas, Eastern American Energy Corp., and Hall Drilling, LLC.

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/oil_gas/rpd/shaleusa5.pdf
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
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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/oil/shale/tabid/23174/Default.aspx
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http://www.dcnr.state.pa.us/topogeo/pub/pageolmag/pdfs/v38n1.pdf
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https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/DataExports/DataExports.aspx
http://www.fs.fed.us/r8/gwj/
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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 Black Warrior Basin.

Also in central Alabama, in the second half of 2010, Hillwood Energy (Dallas) and their partner Endeavour International Corporation drilled and cased two vertical wildcat wells in Greene County. These wells are on strike with a previous Chattanooga test drilled several years ago by EOG Resources which test gas from Devonian shales before being plugged. The Hillwood, Caldwell 19-15 #1ST was perforated and fracture stimulated in the Devonian shale section; but the well is currently abandoned temporally. Hillwood is currently preparing to re-enter the second well (Tate 9-4 #1) and drill a horizontal sidetrack in the Devonian shale section.

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.

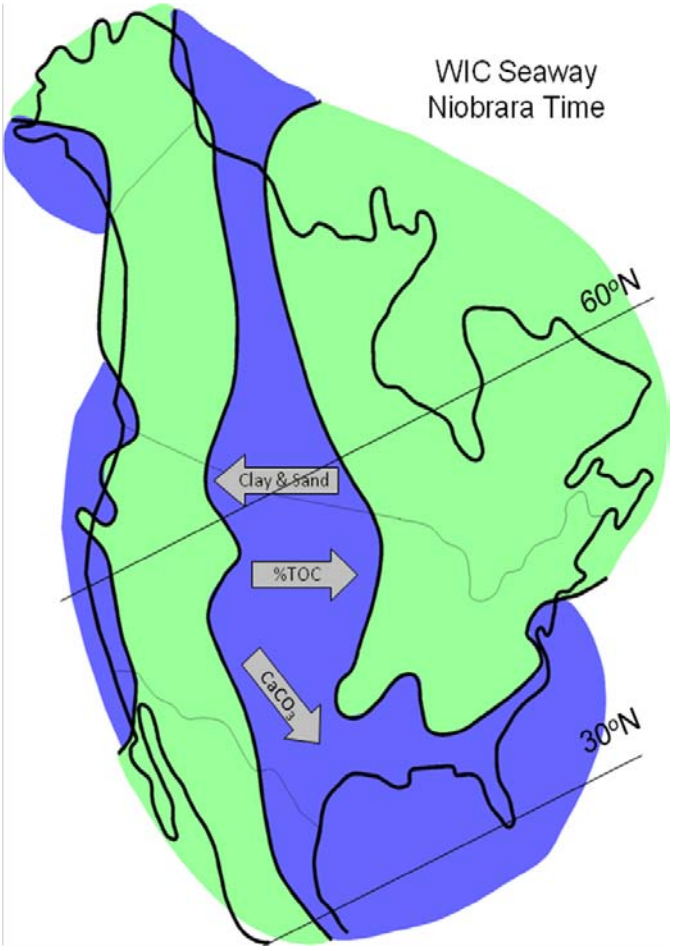

Figure 1. The Western Interior Cretaceous Basin during Niobrara time (modified from Longman et al., 1990). Source area for clastics is dominantly to the west, total organic carbon content in the Niobrara increases to the east, carbonate content generally increases on the eastern side of the Western Interior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

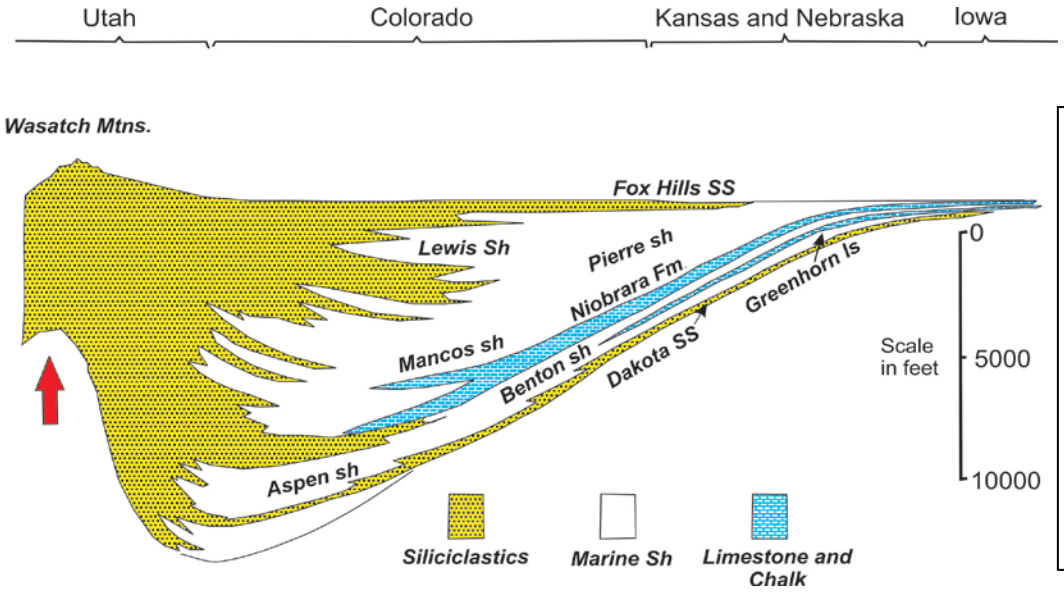

Figure 2. Generalized cross section across the Western Interior Cretaceous Basin. The Niobrara is Upper Cretaceous in age. Limestone and chalk beds are present over the eastern two thirds of the basin (modified from Kauffman, 1977).

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.

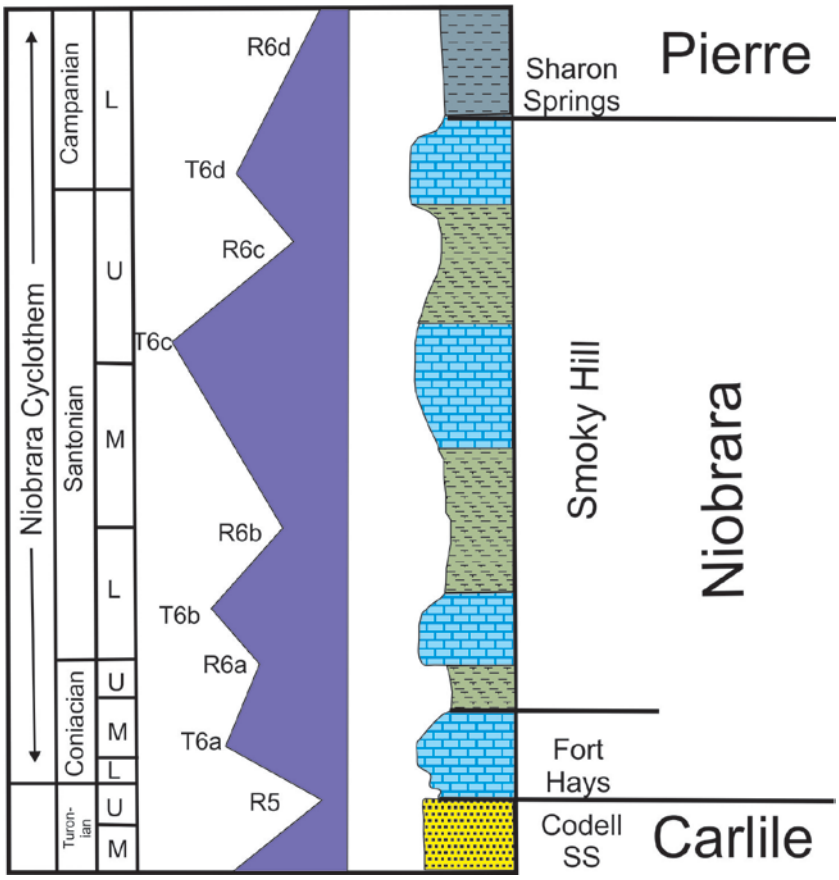

Figure 3. Generalized stratigraphic column for the Niobrara from the Denver Basin setting. The Niobrara ranges in age from Coniacian to lower Campanian. Several transgressive and regressive cycles are noted for the Niobrara interval. Four chalk –rich intervals were deposited during trangressive events , 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.

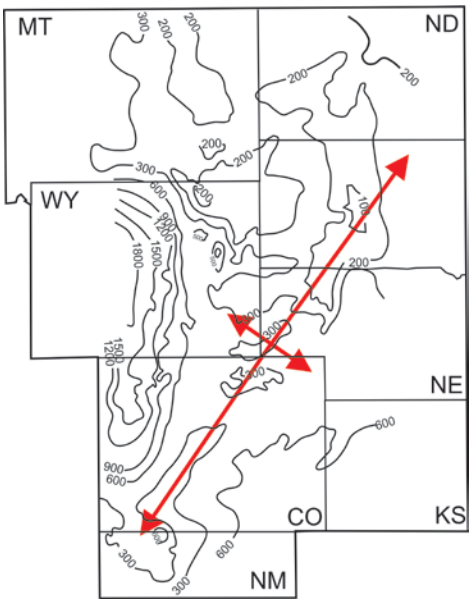

Figure 4. Isopach of the Niobrara across the northern Rockies (modified from Longman et al., 1998). The Niobrara ranges in thickness from less than 100 feet to over 1800 feet. Thinning occurs in a northeast trend across the area known as the Transcontinental Arch (Weimer, 1978).

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.

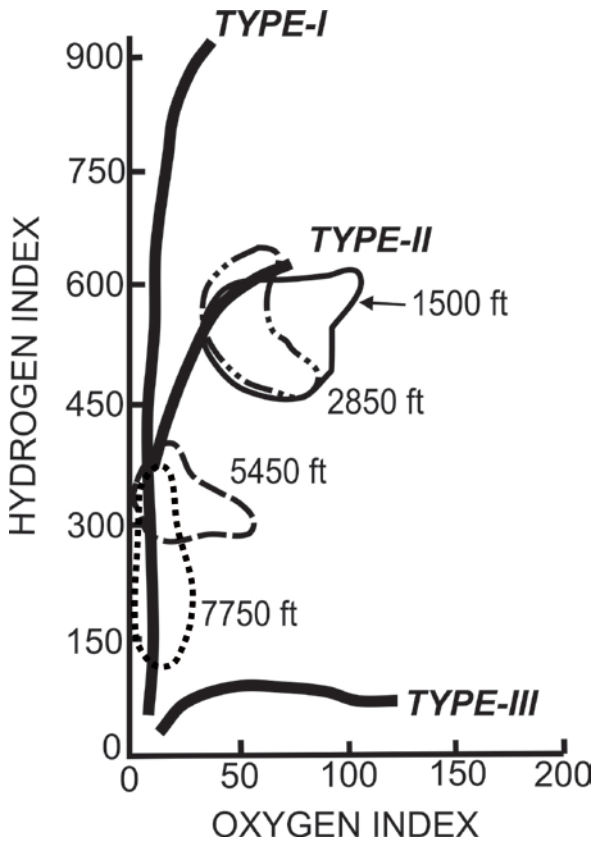

Figure 5. Niobrara Van Krevelen diagram. Niobrara source rocks are Type-II (oil prone) kerogens based on Rock Eval data. With increasing burial depth and thermal maturity the HI values decrease significantly. Data from Rice (1984); Barlow (1985); Pollastro (1985); after Sonnenberg and Weimer (1993).

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

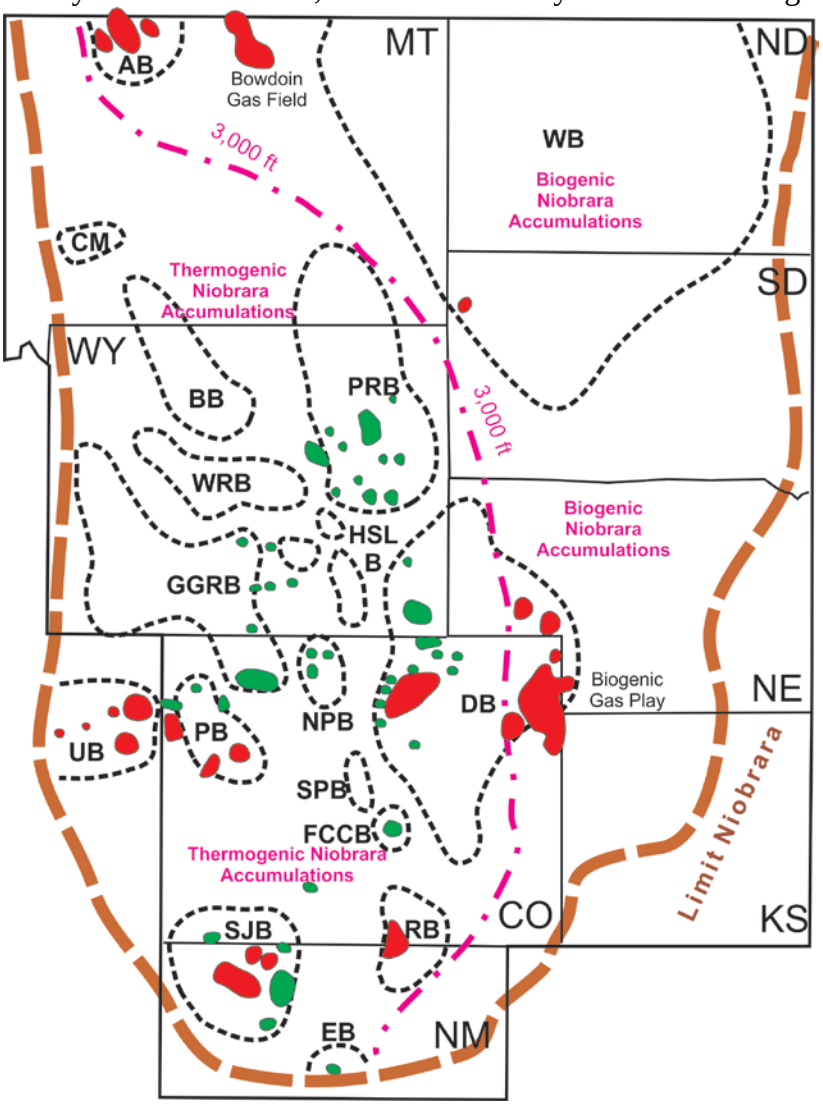

Figure 6. Niobrara producing areas across the north Rockies (Oil fields-green; gas fields-red)(modified from Longman et al., 1998). Basin abbreviations are as follows: AB-Alberta Basin; CM-Crazy Mountain; WB-Williston Basin; BB-Bighorn Basin; PRB-Powder River Basin; WRB-Wind River Basin; GGRB-Greater 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).

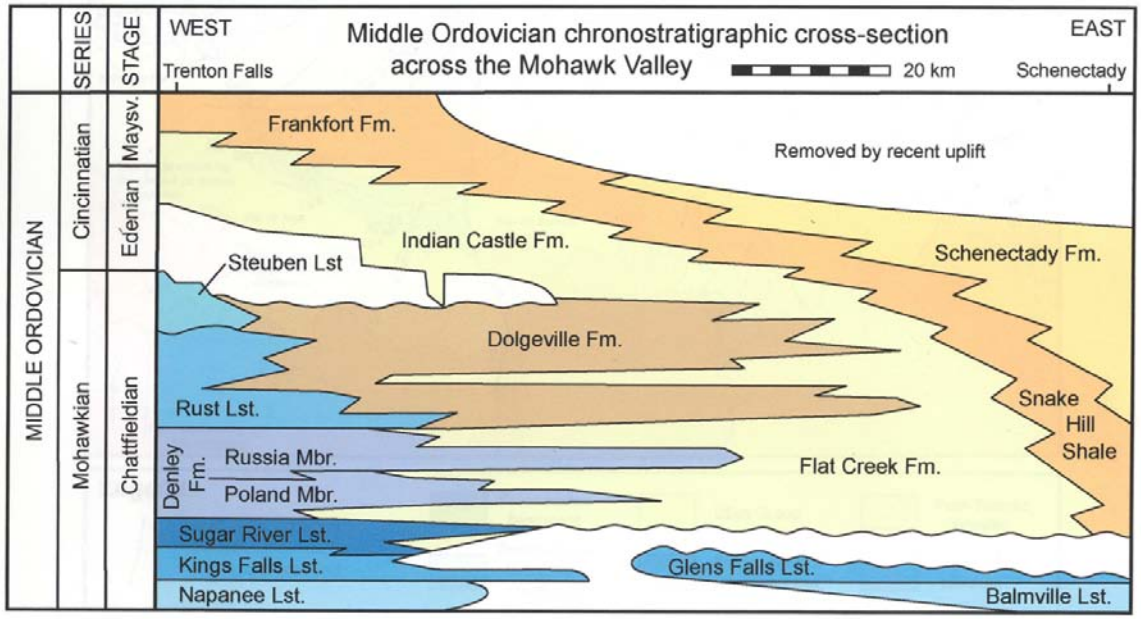
To date these formations have not been correlated from Ohio to New York, but a new consortium might be able to form a collaboration of industry partners and state geological surveys to spur a better understanding of these formations and their reservoir characteristics.

CURRENT:

With the current regulatory moratorium in place in New York, activity has been focused in eastern Ohio and western Pennsylvania. Published results from Chesapeake wells in Ohio and Pennsylvania are very encouraging:

- 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;
- The Mangun 22-15-5 8H in Carroll County, Ohio was drilled to a lateral length of 6,231 feet and achieved a peak rate of 3.1 mmcf per day of natural gas and 1,015 bbls per day of liquids, or 1,530 boe per day;
- The Neider 10-14-5 3H in Carroll County, Ohio was drilled to a lateral length of 4,152 feet and achieved a peak rate of 3.8 mmcf per day of natural gas and 980 bbls per day of liquids, or 1,615 boe per day; and
- The Thompson 3H in Beaver County, Pennsylvania was drilled to a lateral length of 4,322 feet and achieved a peak rate of 6.4 mmcf per day of dry natural gas.

Chesapeake Press Release 9/28/2011

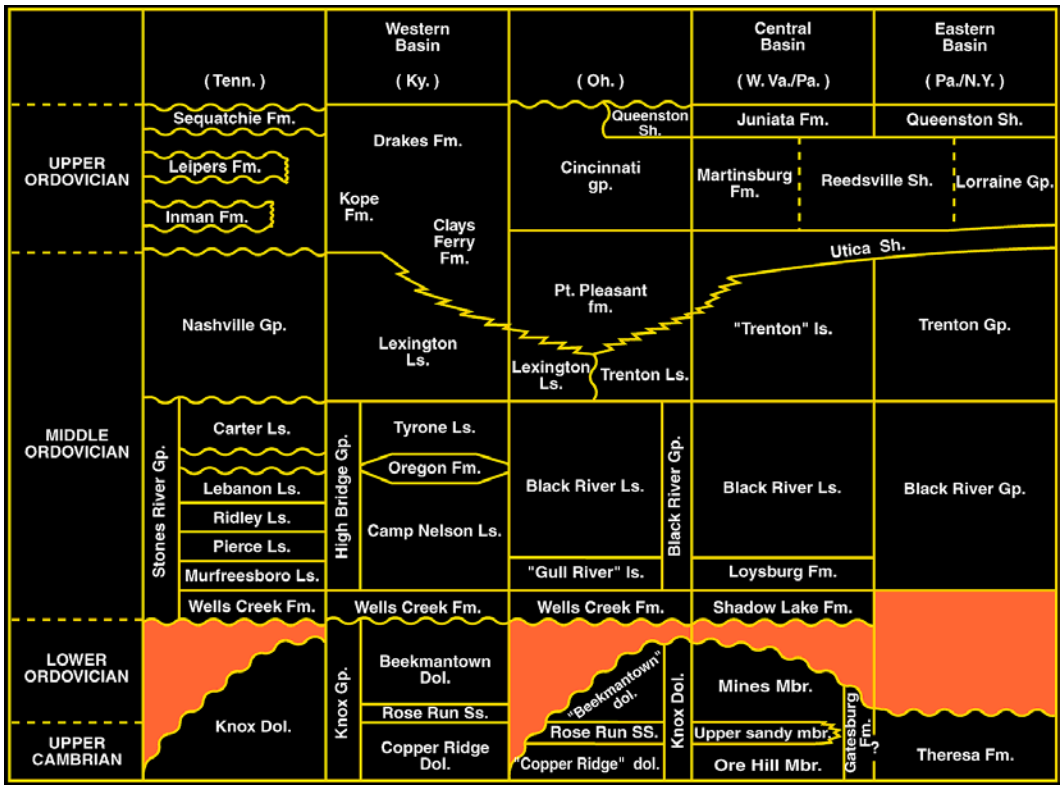


(Cross, 2004)

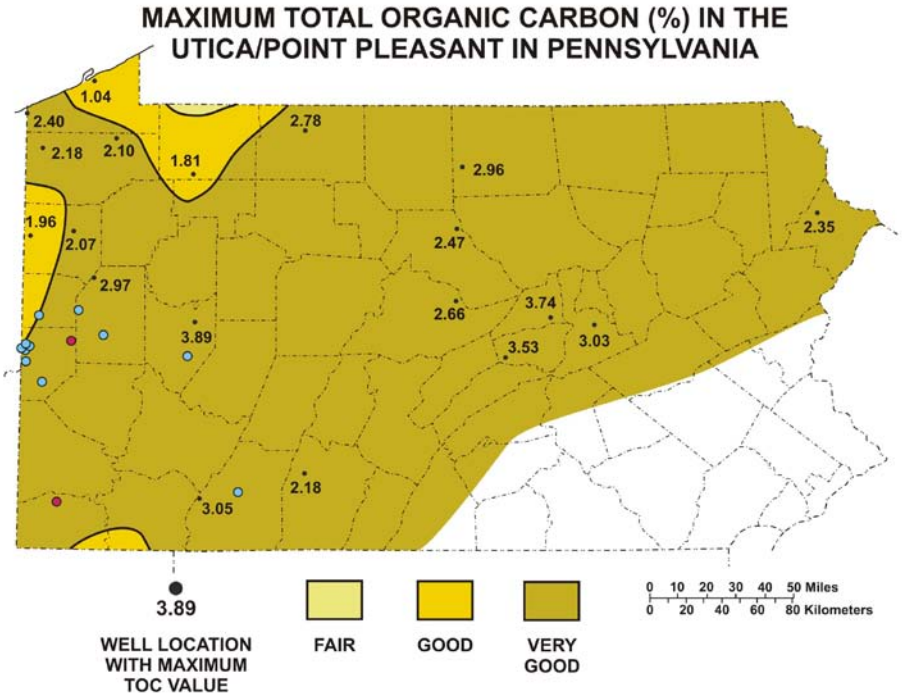
The September 27, 2011 Wall Street Journal reports the 170,000 square miles of Utica Shale sprawls beneath parts of eight states and Canada and believe the richest parts are in eastern Ohio. To date Wachovia Securities analysts report that only 16 wells for production have been drilled into the Utica.

Using Carbon Isotope Stratigraphy , Taury Smith of the New York State Geological Survey found several excursions that can correlate as time lines to correlate the Utica from Ohio to New York . http://www.pttc.org/workshops/eastern_062111/eastern_062111_Smith.pdf

Research is still being performed on well cuttings and cores from the Utica in the New York State Museum collection under the direction of Taury Smith, State Oil & Gas Geologist, to determine the TOC and carbonate content. Currently 70 wells with cuttings and one core have been analysed. Some results have been released and can be found in the Pittsburgh Association of Petroleum Geologists Publications Website

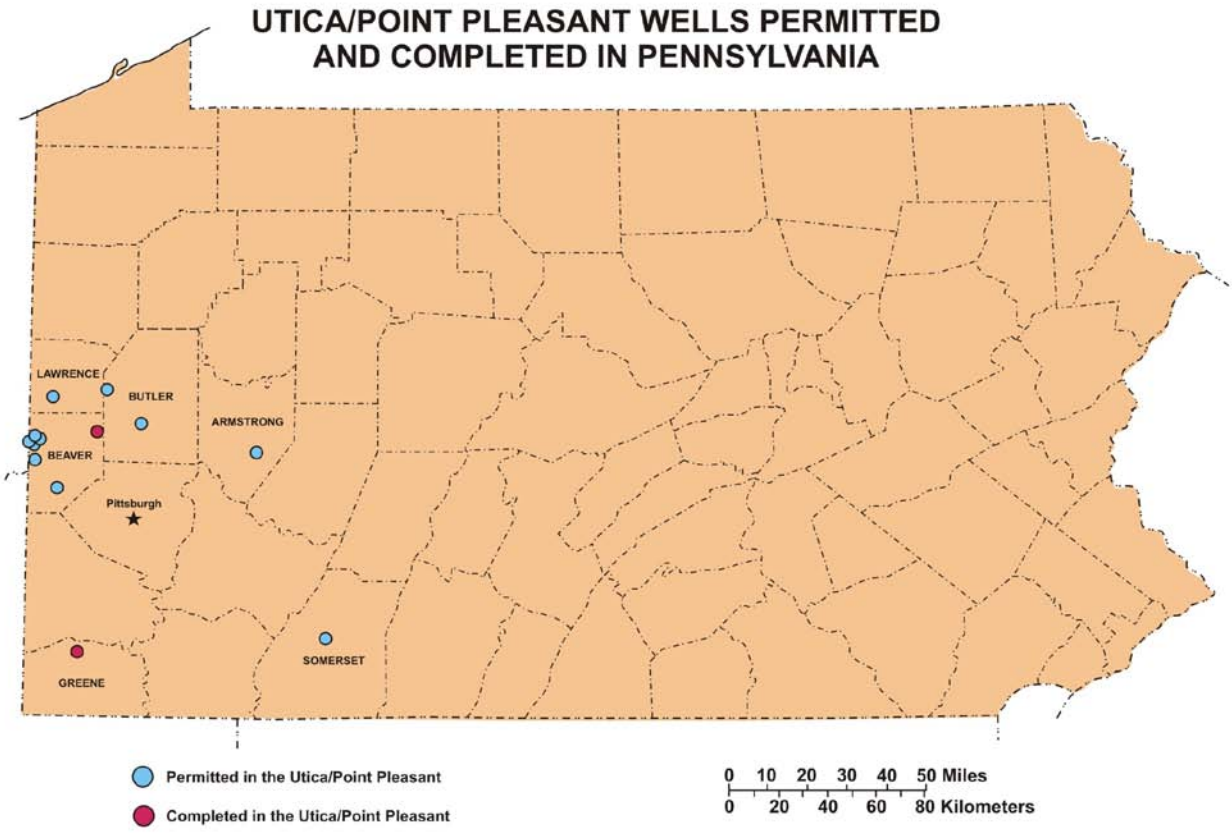


(Wickstrom, 2011)



(Harper, 2011)

(http://www.papgrocks.org/publications.htm). This study is being supported by NYSERDA and companies who subscribe for data from this study.



(Harper, 2011)

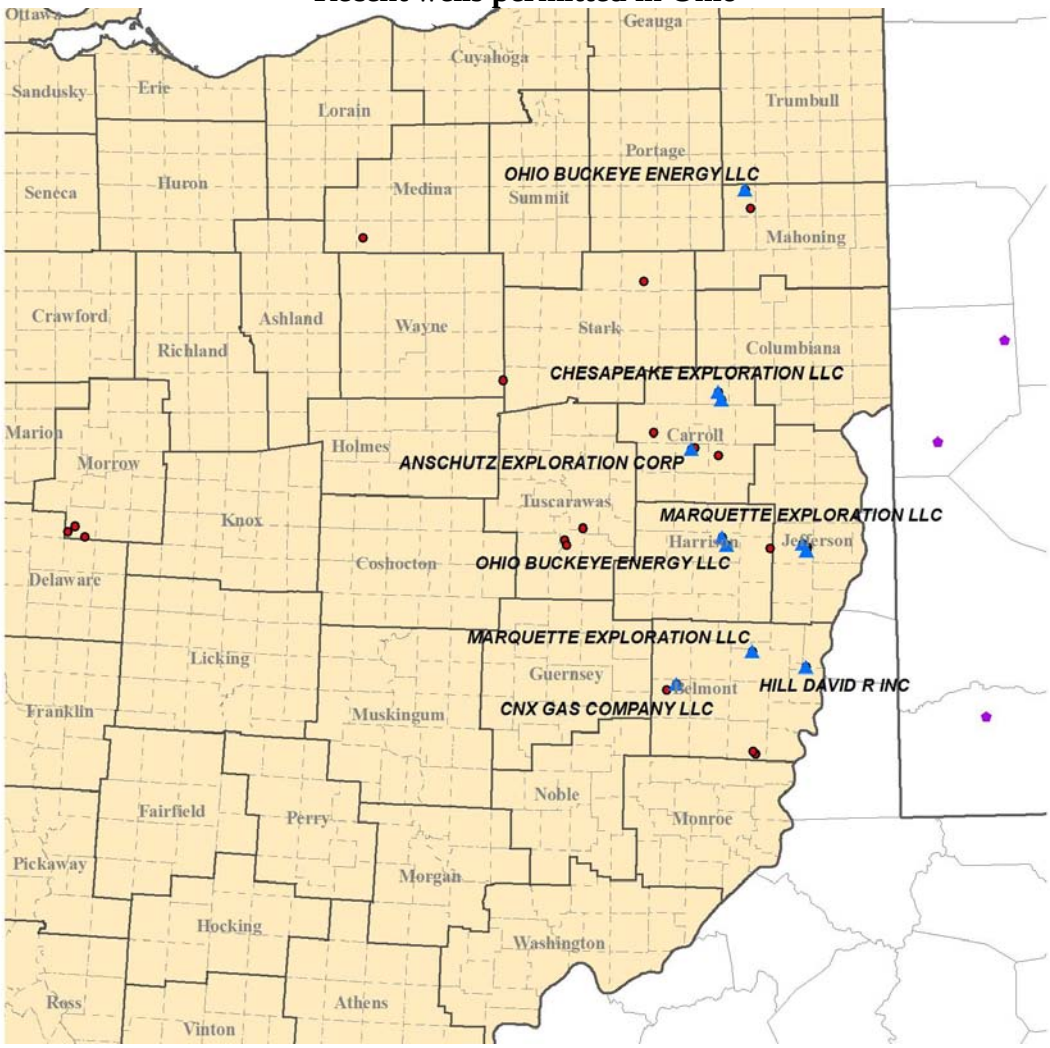
WEB SITES:

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.

Recent wells permitted in Ohio



(Wickstrom, 2011)

ISSUES:

No permits have been issued for horizontal drilling and high-volume hydraulic fracturing to develop the Marcellus Shale or the Utica Shale in New York. The Department of Environmental Conservation has released the draft Supplemental Generic Environmental Impact Statement on September 30, 2009 for horizontal drilling and high-volume hydraulic fracturing to develop the Marcellus Shale and all associated shales. The sixty day comment period for all stake holders was extended until December 31, 2009. Four public comment meetings wereheld in various areas throughout the southern tier of the State. On August 4, 2010 the New York State Senate passed a bill by a vote of 48-9 in favor of a moratorium on permits to be issued for all high volume hydraulic fracturing of Utica and Marcellus wells in New York State until May 15, 2011. In July of 2011, the NYDEC released a preliminary draft and then the final draft was release in September of 2011. The public now has a 90 day period to comment with various comment sessions to held

throughout the state. Permits for Utica high-volume hydraulic fracturing in New York are now expected sometime in 2012.

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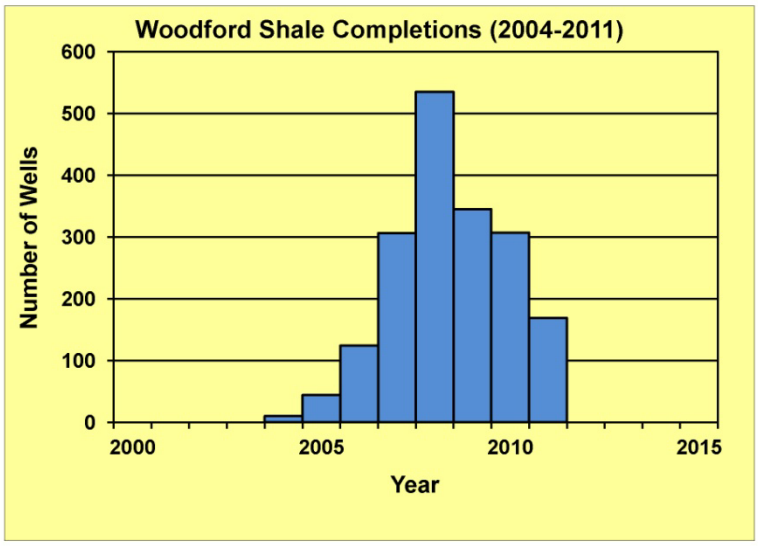
Woodford Shale (Late Devonian-Early Mississippian), Anadarko, Arkoma, and Ardmore Basins, U.S.

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 1,996 well completions from 1939 to the present contains the following shale formations and number of completions: Arkansas Novaculite (3), Atoka Group shale (3), Barnett Shale (1), Caney Shale (82), Excello Shale/Pennsylvanian (2), Sylvan Shale (1), and Woodford Shale (1,905). Shale wells commingled with non-shale lithologies are not included. Exceptions include 13 Sycamore Limestone/ Woodford Shale vertical completions and 2 Hunton Group carbonate/Woodford Shale horizontal completions. The database was originally restricted to shale gas wells. Shale oil wells have been added since 2004.

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. 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 1,847 Woodford-only well completions since 2004, 102 wells are classified as oil wells, 1,465 wells are horizontal wells, and the annual peak of 535 wells occurred in 2008. 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 four Woodford shale plays in Oklahoma are as follows:

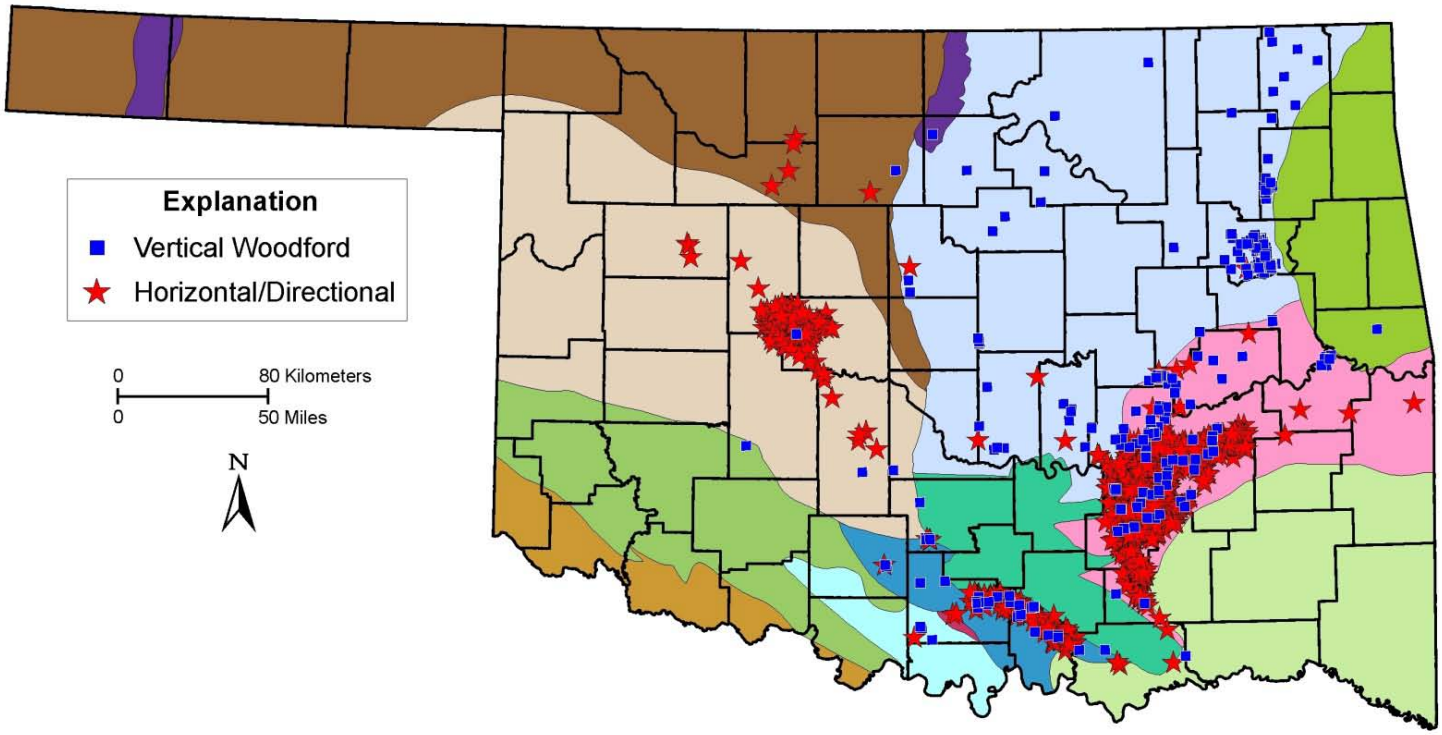
1) western Arkoma Basin in eastern Oklahoma with thermogenic methane production at thermal maturities from <1% to >3% vitrinite reflectance (VRo) and condensate production up to @1.67% VRo;

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.

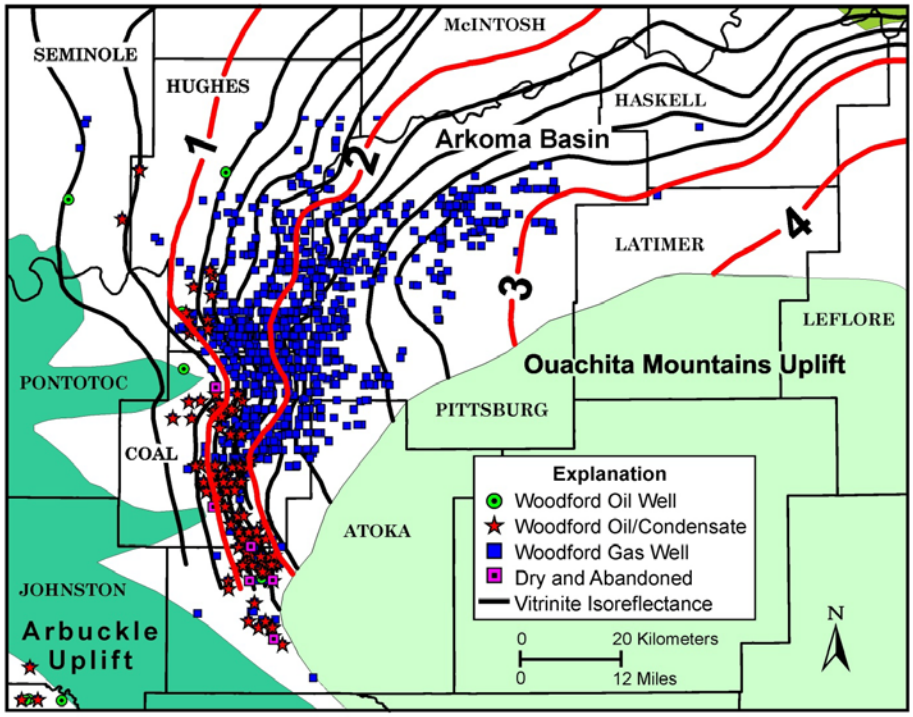
Of 31 operators active in the first nine months of calendar year 2011, the top five operators (for number of wells drilled during 2011) are:

(1) Devon Energy Production Co. LP (41)
(2) XTO Energy (34)
(3) Newfield Exploration Mid-Continent Inc. (20)
(4) Petroquest Energy (12)
(5) BP America Production Company (9)

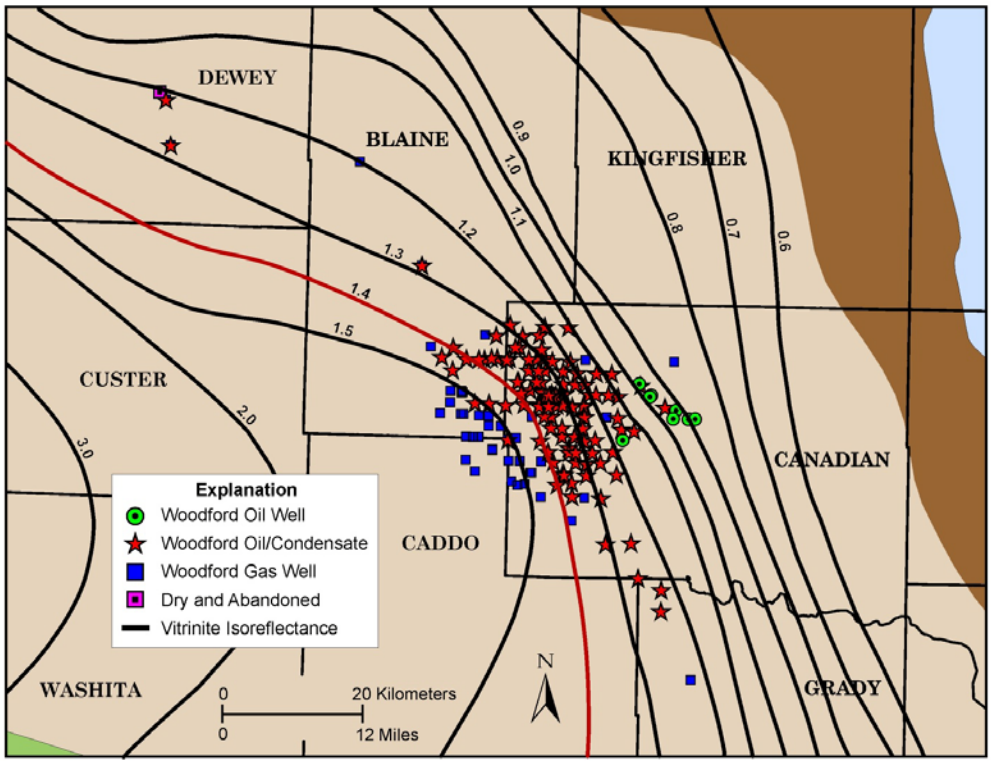
For additional information, visit the Oklahoma Geological Survey web site (http://www.ogs.ou.edu/level3-oilgas.php).



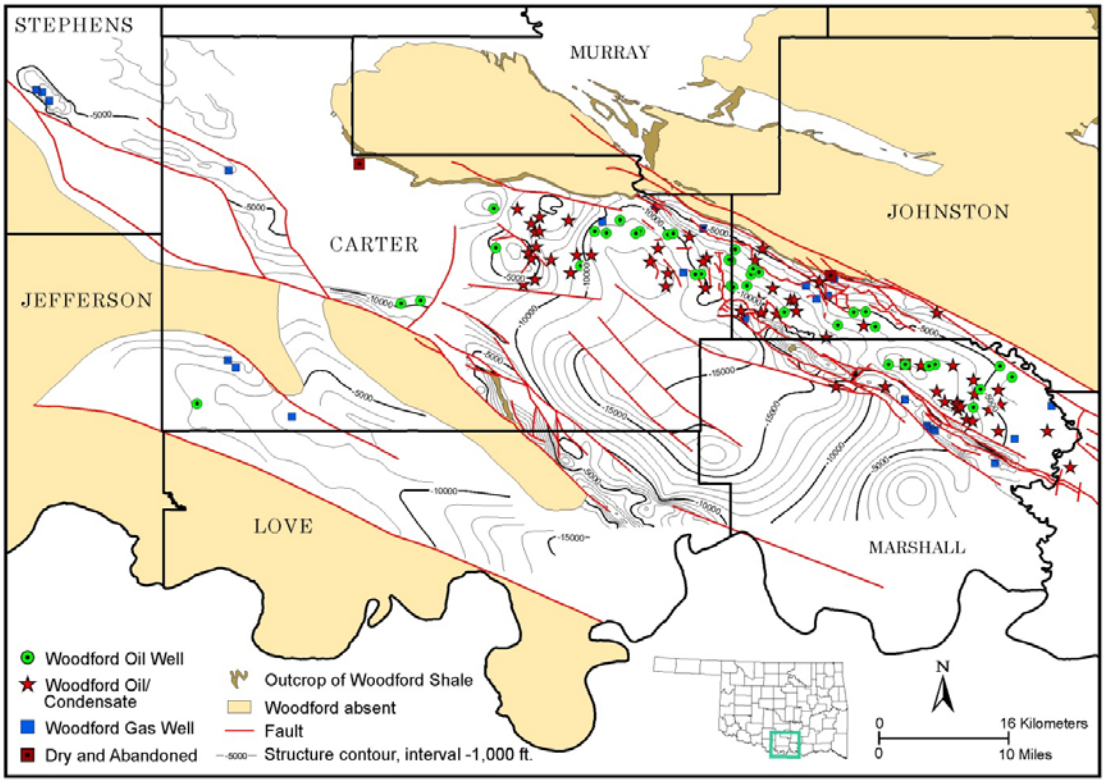
Map showing Woodford Shale-only gas and oil well completions (2004-2011) on a geologic provinces map of Oklahoma modified from Northcutt and Campbell (1998).



Map showing Woodford Shale gas and oil/condensate producing wells in the Arkoma Basin (2004-2011) on an unpublished Woodford vitrinite isoreflectance map.



Map showing Woodford Shale gas and oil/condensate producing wells in the Anadarko Basin (2004-2011) on a Woodford vitrinite isoreflectance map from Cardott (1989)



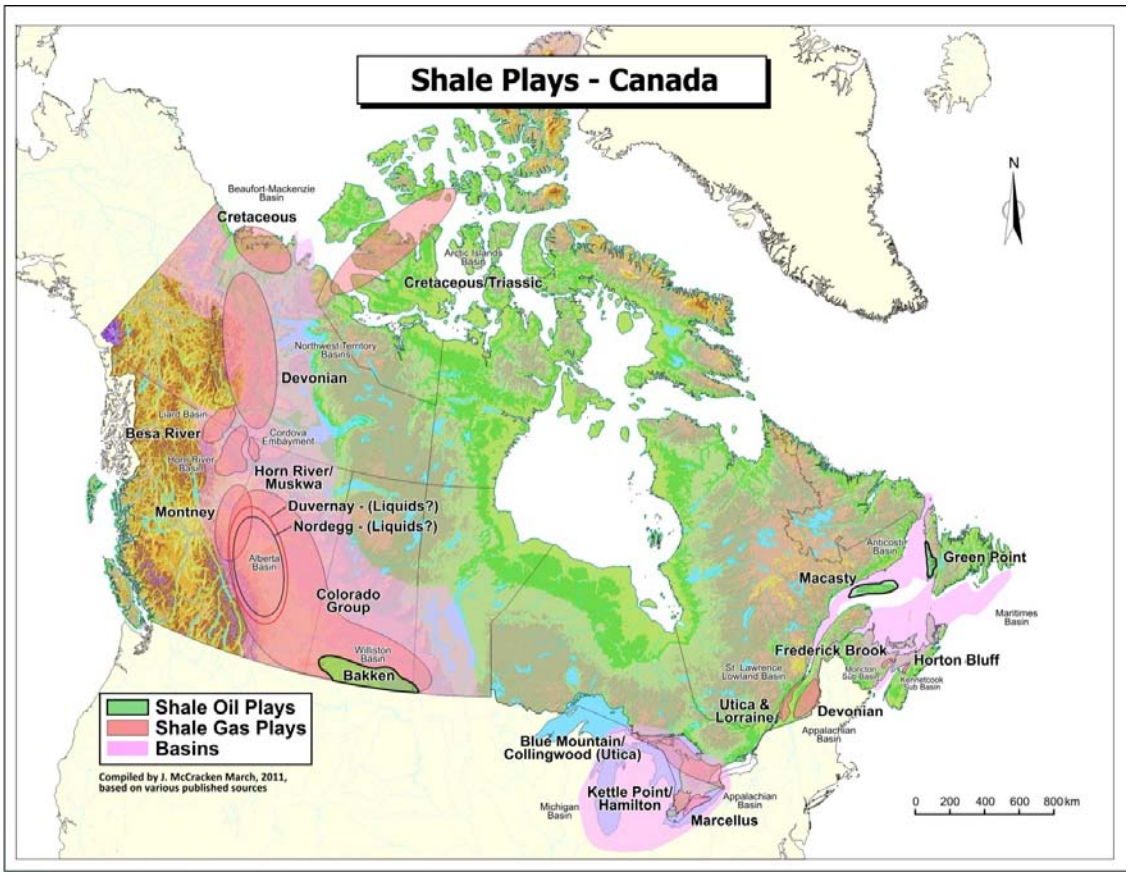
Map showing Woodford Shale gas and oil producing wells in southern Oklahoma (2004-2011) on a Woodford structure map from Wagner & Brown Ltd.

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 now almost 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 behind. Additional production numbers and exploration statistics for this report are therefore gathered from press releases and presentations from some of the companies involved with the plays.

Recently there have been some new discoveries in Alberta that are exciting 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 environmental concerns will slow down any future production. The positive announcements out of New Brunswick have been tempered by recent disappointing results. To date there is Shale exploration activity in 9 provinces of Canada out of the 10 with Prince Edward Island being the exception. There has been significant bad press about hydraulic fracturing in various locations across Canada hindering or slowing down exploration and/or production.



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 more than $4 billion since the record year in 2008. The bonuses have reduced somewhat since then as the available land is reduced. In 2009 it was $803 million and 2010 it was $796 million and this year in 2011 it has been about $148 million up through Oct. These Triassic to Devonian British Columbia shales are estimated to have the capacity to hold 250 to 1,000 + trillion cubic feet (TCF) of original gas-in-place.

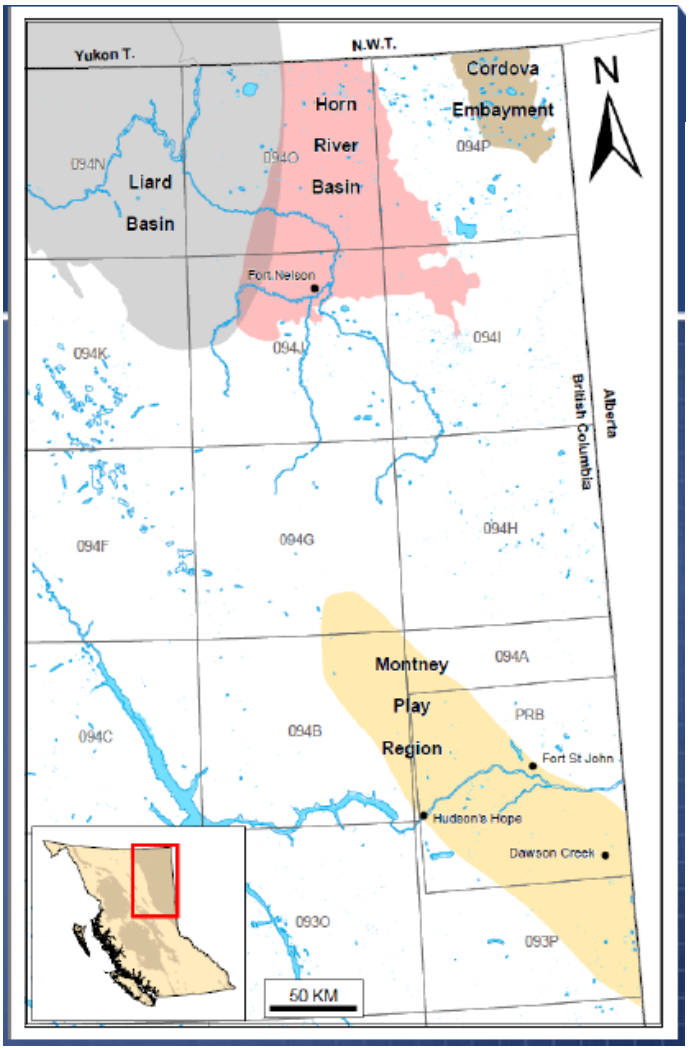
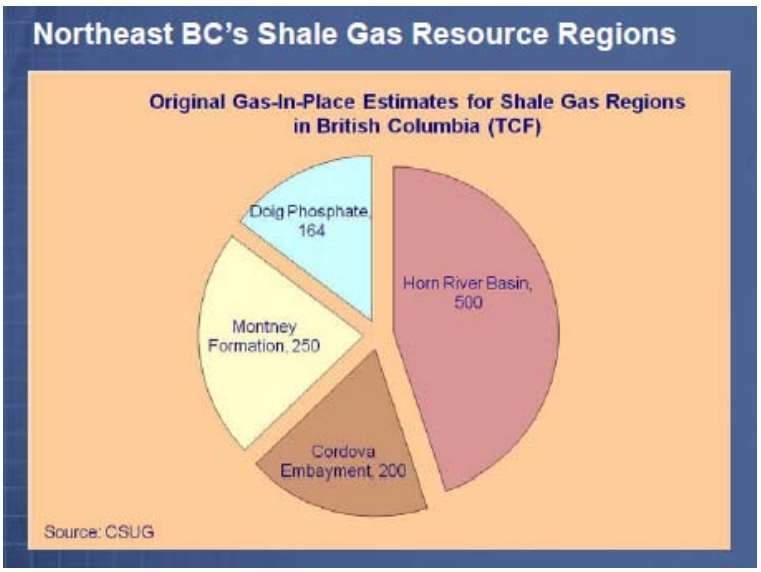


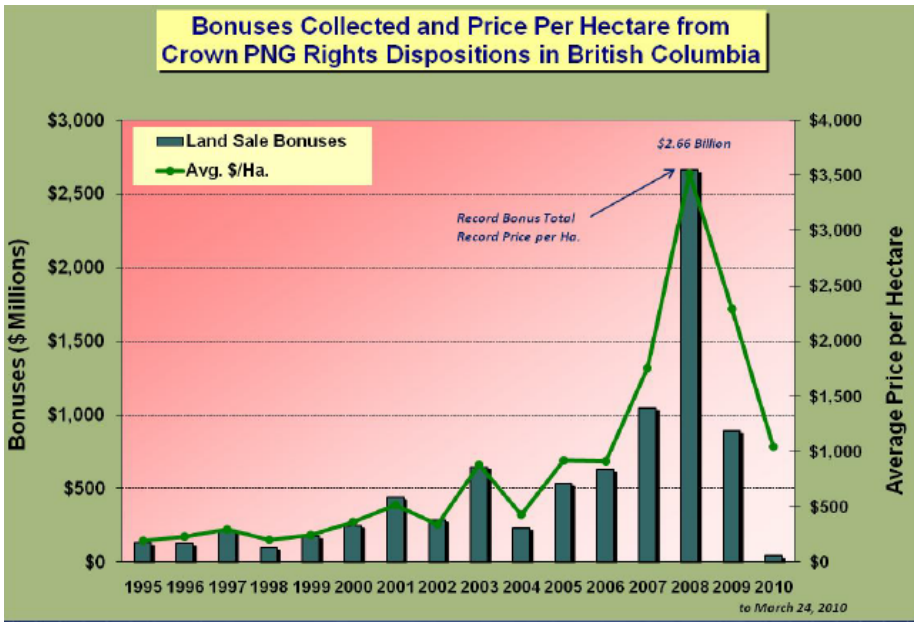
TABLE 1. POTENTIAL SHALE GAS FORMATIONS IN NORTHEAST BRITISH COLUMBIA

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.



Devonian Muskwa Shale

Horn River Basin, Cordova Embayment and the Liard Basin

Of these very far north basins, the Horn River has the most activity. There were some reports that the Horn River production is now at approximately 80 MMCFD at the end of 2009. Government numbers are not published yet because of the confidentiality in this relatively young play.

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 Canada Ltd, ConocoPhillips Canada, Devon Canada Corporation, Encana, EOG Resources Canada Inc., Imperial Oil Resources Limited, Nexen Inc., Pengrowth Energy, Suncor Energy, Quicksilver Resources Canada Inc., Stone Mountain Resources Ltd. /Ramshorn Canada. Other companies working this area are Taqa North, Storm Gas Resources, Canadian Natural Resources, and Hunt Oil of Canada among others.

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 Nov 2010, are Apache, Encana, EOG, Devon and Nexen.

Apache has been the most active since 2003. Last year they finished a 16 well pad, drilled 29 horizontal wells and reached production of approximately 100 MMCFD (gross). They are planning completion of two more pads this year with another 42 wells coming on stream.

Encana has drilled 41 shale wells since 2003 with 16 wells drilled in 2010. They lead the way with multiple fracture stimulations of up to 28 per well. 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 Kogas Canada Ltd., a subsidiary of Korea Gas Corporation (KOGAS), have entered into a three-year exploration and production agreement.

EOG completed 11 wells in 2010 but planning minimal drilling in this year to hold the acreage.

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.

Nexen began fracture stimulation on eight wells last year with production expected in 2011. They are currently producing 40 to 50 MMCFD. They have a 9 well pad on stream with an 18 well pad drilling and on stream in late 2012.

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.

The Cordova Embayment area, 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 third quarter 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.

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, to be opened in 2015. 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 for late 2011. 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 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. Shell Canada has plans of its own to build a West Coast LNG facility with Korea Gas Corp., Mitsubishi Corp. and the China National Petroleum Corp.

Triassic Doig and Montney

Dawson Creek Area

The Montney is a tight gas/shale gas play with this trend producing at approximately 472 MMCFD at the end of 2009. The primary zones are the Upper and Lower Montney. 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 Doig has potential but the Montney has been the focus. 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 decreasing production are Encana, Murphy, ARC Energy, Shell Canada Ltd., CNRL, Talisman Energy, Tourmaline, Birchcliff, Crew and Advantage. There are many other players as well.

Encana is by far the biggest player with 482 rig releases since 2005. They drilled 90 wells in 2009 with 8 to10 wells per section and 62 wells in 2010. 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.

Murphy has concentrated their efforts in the Tupper and Tupper West area and is now producing at 210+ MMCFD with 129 wells on production. Their Montney production is about 250 MMCFD.

Shell with 174 well rig releases since 2005 now has holding of 210,000 net acres in the prime Montney fairway. In October 2010 they reported production of 170 MMCFD from their Groundbirch complex. There current Montney production is about 220 MMCFD. They anticipate drilling up to 280 wells per year in 2014 from the current 100 wells per year.

ARC Energy trust is another dominant player in the Dawson Creek area recently achieving an average production of 110 MMCFD at the end of 2010 with a current production of 245 MMCFD. They just brought on stream in 2010 a 60 MMCFD gas plant with two more to follow by 2014. In 2011 they will be drilling 14 wells.

Talisman recently partnered up with South Africa's Sasol in the Montney area.

Progress Energy Ltd. has amassed approximately 900,000 net acres of land within the commercially productive Montney fairway which represents one of largest land positions among all North American natural gas resource players. It partnered with the Malaysian national oil and gas company, Petronas recently.

The graph below shows the well production in the Montney.

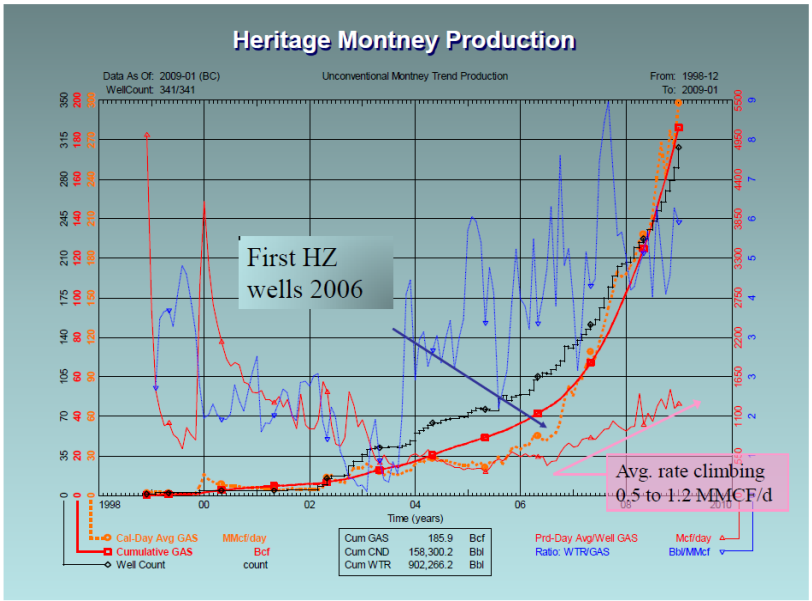


Figure 13. Chart displaying area gas production and total number of producing wells from the Heritage Montney. Horizontal drilling technology along with new and improved completion techniques are key factors in the increasing production profile from these areas. Data from Hayes (2009).

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 74,000 net acres of Buckinghorse potential with 3 wells on production and 2 more wells planned this year. No production numbers announced yet. Canadian Spirit is another player in the area, mostly with experimental schemes, on the Gething. No production volumes reported yet.

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

http://www.aapg.org/explorer/2010/10oct/regsec1010.cfm

http://www.em.gov.bc.ca/OG/Documents/HornRiverEMA_2.pdf

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.

Lower Jurassic Nordegg (Gordondale)

West Central Alberta

Anglo Canadian Oil Corp. is currently 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

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. The relatively small foot print 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.

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.

Encana announced that their two wells produced 2 to 5 MMCFD and 158 to 390 bbl per day respectively. 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.

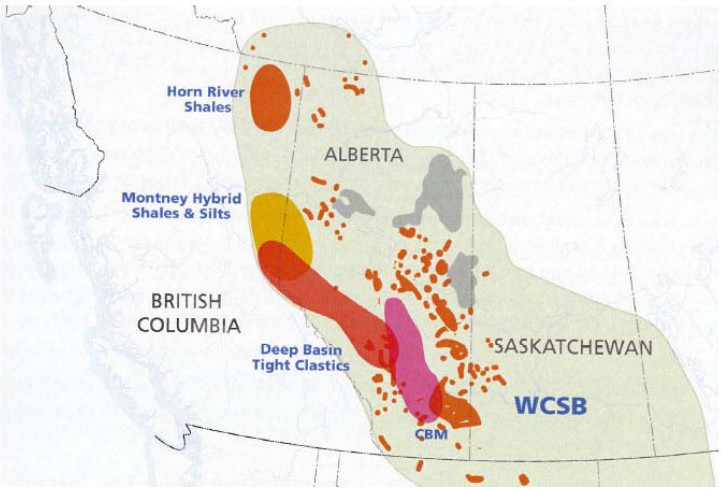
Yoho Resources and Celtic Exploration are also playing this interval. Yoho sees 80-105 bcf/sq. mile of gas in place in shale 130-180 ft. thick with 7.1% average effective porosity and 1-4% total organic carbon. Other independents that hold Duvernay acreage include Mooncor Oil & Gas Corp., Galleon Energy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

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. No numbers have been published yet. 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 >50 test wells were drilled for shale gas 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.

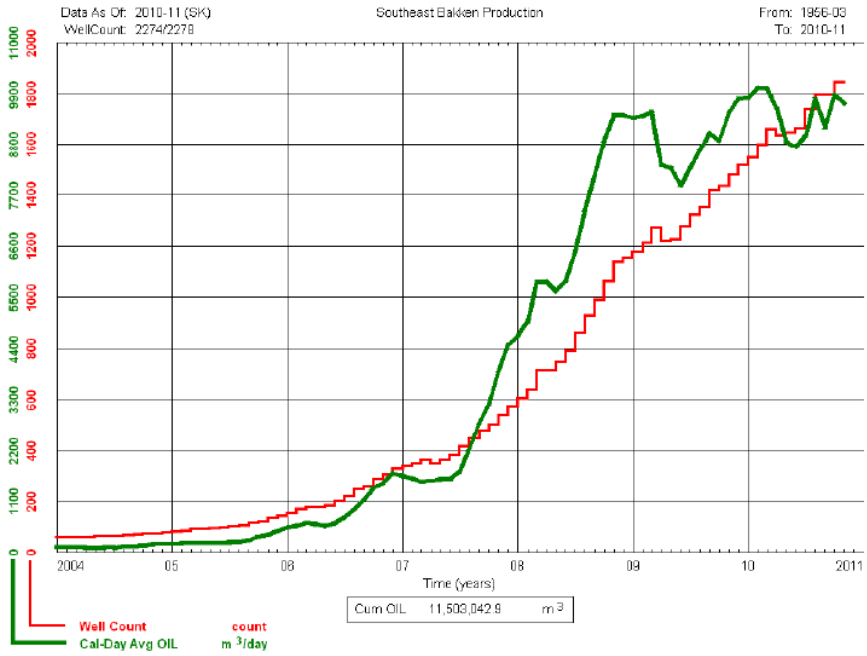
There has also been some activity in the Pasquia Hills in central east Saskatchewan. Pasquia Hills has a huge potential for Oil Shale in this area but there have been about 23 wells drilled by various operators with gas shows and some limited gas tests. Nordic announced recently that survey work has 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.

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 but two of the bigger players are Crescent Point with 42,000 BPD and PetroBakken with about 30,000 BPD.

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



Bakken Production 2004-2010

Currently producing 9900m³/day (60,000bbls/day)

MANITOBA

Cretaceous Colorado Group

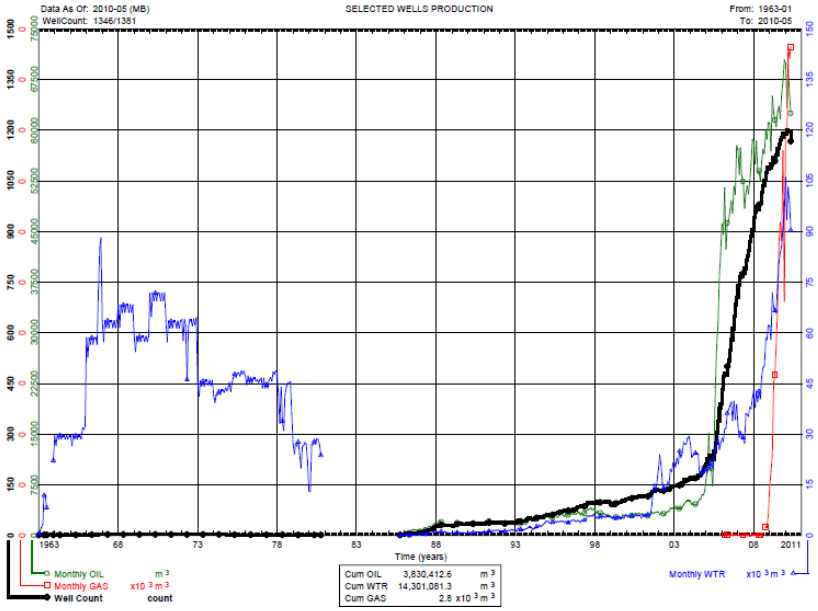
There is the potential of shale gas in Manitoba, but no activity or production. There have been a number of publications on the shallow shale potential by Nicholas and Bamburak.
http://www.wbpc.ca/assets/File/Presentation/11_Nicolas_Manitoba.pdf and Nicholas 2011
http://www.wbpc.ca/assets/File/2011%20Presentations/Tuesday/Nicolas%20WBPC%202011_Shale%20gas%20to%2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

. 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.

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 ft 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/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

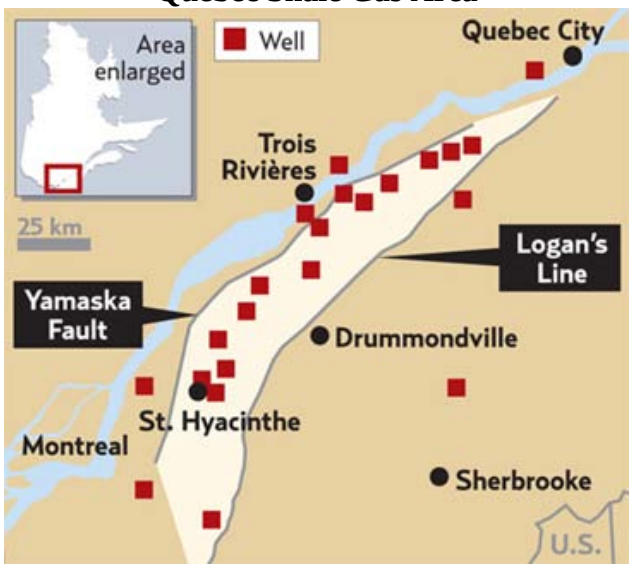
Quebec's natural gas royalty, which currently is 12.5%, has been described as attractive by some of the players. As well, shale gas plays in the province's St. Lawrence Lowlands enjoy another advantage in being close to the northeast U.S. gas market.

Quebec Shale Conference 2010 and 2009

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

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

Quebec Shale Gas Area



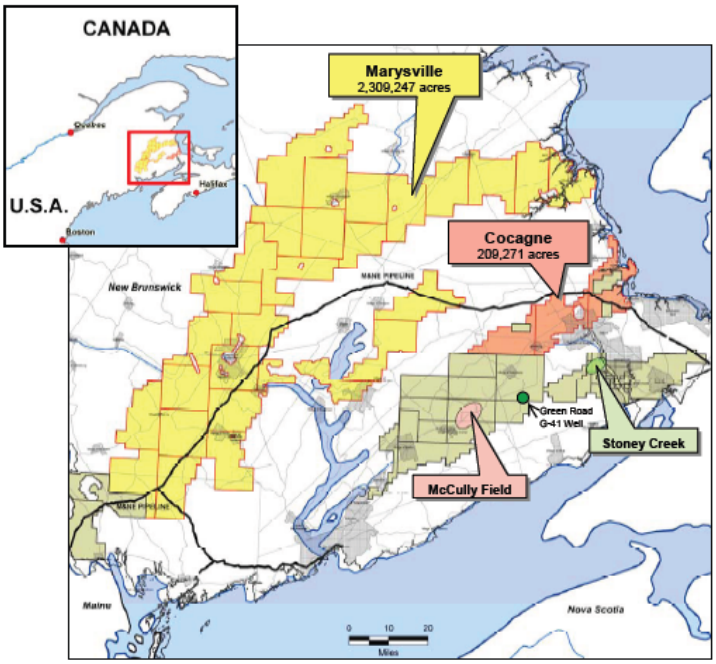
http://www.apgq-qoga.com/en/2011/07/20/qoga-annual-conference/

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

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. 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. 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 the first well in 2012.

"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
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 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.

Additional exploration elsewhere in the province is underway on the Horton Bluff, although no additional information is currently available.

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 thermogenic shale gas and oil 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). A well drilled in 2008 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 the same companies with recent drilling confirming the above. Testing will commence before the end of the year.

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/

The Canada-Newfoundland Labrador Offshore Board (C-NLOPB) is the regulator for the offshore portion.

http://www.cnlopb.nl.ca/

Western Newfoundland Oil & Gas Convention

http://www.wnloilandgas.com/

Societies, Conferences and Courses

B.C. Unconventional Gas Technical Forum 2011, April 5-6, 2011, Victoria, B.C.

http://www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/UnconventionalGas/Pages/default.aspx

Canadian Society for Unconventional Resources (CSUR)

Note the name change to reflect oil and gas liquids plays.

http://www.csur.com/

Canadian Unconventional Resources Conference (CURC11)

http://www.spe.org/events/curc/2011/index.php

15-17 November 2011

BMO Centre at Stampede Park

Calgary, AB

The Canadian Unconventional Resources Conference is a joint meeting of the Canadian Society for Unconventional Gas and the Society of Petroleum Engineers.

Last year, we introduced this conference as the Canadian Unconventional Resources and International Petroleum Conference. This year, we changed the name to reflect our focus of presenting the latest knowledge on discovering, developing, and producing unconventional gas and heavy oil in Canada and the United States.

Presentations

Note CSUR has a number of good presentations on their websites including a few good summaries of hydraulic fracturing.

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

CSPG

http://www.cspg.org/

GeoConvention 2012: Vision – CSPG,CSEG and CWLS

May 14 -18, 2012, Calgary

www.geoconvention.org

Canadian Natural Gas/Shale Gas

http://www.canadiannaturalgas.ca/natural-gas-supply/shale-gas

Canadian Institute 8th Annual Shale Gas & Oil Symposium

Jan 24-25, 2012, Calgary Alberta

http://www.shalegassymposium.com/

Nineteenth Williston Basin Petroleum Conference 2011 – May 1-3, Regina, Saskatchewan.
http://www.wbpc.ca/
The 2011 papers are available for download from this site:
http://www.wbpc.ca/technical_program

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Shale Gas/Shale Oil in Europe

By Ken Chew

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. On the other hand, the Midland Valley of Scotland, where Europe's first certification of recoverable shale gas resources has taken place, is considered by the 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 fifteen 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. Dart 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 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 applied for / awarded over the Fennoscandian Border Zone and Norwegian-Danish Basin onshore Denmark.

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).

Aura Energy, an Australian uranium exploration company that is investigating the uranium potential of Sweden's Alum Shale, has commenced drilling at its Motala shale gas project in 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 24 concessions in Östergötland (19) and on the island of Öland (5).

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 39 concessions have been awarded in the Baltic Depression, of which 7, operated by LOTOS Petrobaltic, are offshore in the Baltic Sea and 32 lie onshore in the Gdansk Depression. Another 35 concessions have been awarded in the Danish-Polish Marginal Trough and 13 on the East European Platform Margin, northeast of the Marginal Trough.

Eleven different companies or consortia are active in the onshore Gdansk Depression including a number of small niche players, but of the 48 concessions on the Platform Margin and Marginal Trough, 20 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.

The first tests of the Polish Lower Paleozoic are now well under way. 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) in the Gdansk Depression. 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 multi-stage hydraulic frac is planned for Q4 2011. 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 drilling contractor, NAFTA Pila, which drilled the first two Lane wells spudded Wytowno S-1 (Slawno concession, Gdansk Depression) 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 300' deeper 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'. 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 will commence the drilling of three wells on its wholly-owned blocks to the south of the Saponis Slawno and Slupsk concessions in February 2012.

An interesting feature revealed by sampling and gas shows from the three wells is that thermal maturity appears to decrease in an approximately northeast direction leading to an increase in the content of NGLs. The Starogard well produced hydrocarbons up to pentane and the others produced methane, ethane and propane. This does suggest that there is the potential for significant liquids production from some concessions.

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.

San Leon / Talisman plan a three vertical well program in the Gdansk Depression which commenced with the spudding of the Lewino 1G2 well in the Gdansk-W concession in late September 2011. Eni also has a 6-well programme planned for its Gdansk Depression acreage, starting in 2011.

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), have been drilled by ExxonMobil. The wells appear to have been successful as the company has indicated that Krupe-1 has now been fractured and that the first fracs on Siennica-1 were to be carried out during the first week of October 2011.

PKN Orlen spudded its first well (Syczn) in the Danish-Polish Marginal Trough (Lublin Trough) on 24th October 2011. Further wells in the Lublin Trough should be drilled in 2011 by Chevron and PGNiG (the Lubycza Królewska-1 well on the Tomaszów Lubelski concession). Marathon also plans to drill at least one well in Q4 2011 though it has not indicated which area it will test.

The Polish Treasury Ministry is said to be targeting production of 20 – 30 million cf/d in 2014, most of which, it is assumed, will come from the Lower Paleozoic play.

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.

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 and the Fore-Sudetic Monocline (Northeast German-Polish Basin) in southwest Poland. The age of the most prospective shales appears to young westwards from the Visean (Middle Mississippian) Kulm facies of southwest Poland 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.

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.

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 2012 as a result of additional drilling planned on Cuadrilla's UK Bowland Shale acreage (below). 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 15 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 an 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.

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 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 the third well in the area, Becconsall-1, which spudded on 16th August 2011. Top Lower Bowland Shale was forecast at ~ 8,000', significantly deeper than the previous two wells.

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.

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. Before end-September 2013 eCorp is scheduled to drill one vertical well in the Gainsborough Trough area to a depth of 14,750' or sufficient to test the Dinantian shale.

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.

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.

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 (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.

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. TransAtlantic has estimated the gross prospective undiscovered recoverable resource at 7.2 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.

Czech Republic.

Cuadrilla Resources has applied for acreage in the Vienna Basin area. It is assumed that the target will be the same as in Austria, the Upper Jurassic Mikulov Formation.

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 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 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.

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.

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).

Spain.

Applications that are presumed to be for shale gas exploration have been submitted in the Basque-Cantabrian Basin (Realm), 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) and Realm Energy have both been awarded two concessions in the basin, 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.

Switzerland.

In addition to the Lower Jurassic Posidonia Shale, Schuepbach is also targeting 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.

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.

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 and the Netherlands. The Upper Jurassic is understood to be a target in the south of the United Kingdom.

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 six-well drilling program, operated by Hess, is now expected to commence by end-2011, but without hydraulic fracturing.

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, 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'.

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 in 2011 but it is unclear whether this refers to the Lower Stumble shale oil test on PEDL 244 or a well on EXL 1879.

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 and acquisitions

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 deal is expected to close in November 2011. On completion of the deal, San Leon will acquire 3 licences in Poland, 1 in Germany and 8 in Spain. In addition Realm has 10 outstanding licence applications in France and 2 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 is shale gas.

Licence acquisitions

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 licences in the Fore Sudetic Monocline, southwest Poland. The licences 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 licences in the Baltic Depression.

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. 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 licences. ConocoPhillips are funding the initial exploration and evaluation programme but 3Legs Resources remains the operator. ConocoPhillips must determine by 20th March 2012 whether to

exercise an option to take a 70% interest in the licences. If it exercises this option, operatorship will transfer to ConocoPhillips.

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 licences in exchange for covering 60% of the cost of a seismic programme and drilling one well on each of the three licences 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 licences 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 licences, reducing Marathon's interest to 51%. Marathon remains operator. The one licence 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.) through its Polish subsidiary Strzelecki Energia has taken a 49% interest in four ExxonMobil licences in the Podlasie Depression of the East European Platform margin. ExxonMobil retains 51% and operatorship.

Unconfirmed reports suggest that Polish independent PKN Orlen is 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 licences. Orlen has seven shale gas licences in Poland plus one with tight gas potential.

It is also reported that Italian major Eni is considering taking an interest in LOTOS Petrobaltic's seven offshore shale gas licences.

United Kingdom.

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.

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 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 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, due to commence delivery on 8th November 2011, effectively creates 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.

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.

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.

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.

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.

The French Union of Petroleum Industries declared that the cancellation decisions would send a negative signal to international investors and were 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.

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.

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 seem unlikely until Poland's six-month term as President of the European Union ends on 31st December 2011.

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 will now seek input from the BGS and other expert sources before

taking any decision 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.

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!

References

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China Shale Gas and Shale Oil

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Technological innovations in exploration, 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. gas from Barnett) and shale oil (e.g. Bakken oil) in the US drove many Chinese companies e.g. PetroChina, Sinopec, CNOOC, Yanchang Petroleum, Henan Provincial Coal Seam Gas Co., etc. and foreign companies e.g. Shell, ExxonMobil, BP, HESS, Chevron, ConocoPhillips, Statoil to the intention of golden rush for 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 resources (http://www.eia.gov/analysis/studies/worldshalegas/?src=email), which is much more than US's 862 TCF recoverable shale gas resources. Figure 1 illustrates temporal and spatial distribution of the potential shale gas and shale oil plays spanning from Pre-Cambrain Sinian shale in South China to Quaternary shale in Qaidam Basin.

No shales in the world are the same. Hydrocarbon related shales formed in diverse paleogeographic settings in China distribute in different kinds of basins, these basins underwent different tectonic activities. China has many hydrocarbon producing and potential basins or sub-basins. The hydrocarbons were generated from source rocks deposited marine, lacustrine and transitional (coastal) 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 Sichuan Basin, Ordos Basin and Bohai Bay Basin respectively (Figure 2).

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 2.5-3.5%. 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 (1.5-6%) and brittle mineral composition (40-60%). Meanwhile, favorable Cambrian and Ordovician shales were mainly deposited in restricted platform to basin setting in Northwest Tarim basin. The thickness for each shale in Tarim basin is about 100-800m and the shale has 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 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%).

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, most potential shale plays in China are located in thinly-populated areas compared with Europe. In these senses, the favorable significant amount of undeveloped shale gas and shale oil potential opens new opportunities for Chinese and foreign oil companies.

So far, exploration of China shales is in early infancy and everything about the China shales just started from scratch several years ago. No commercial production well so far, even though several wells in Sichuan Basin, Bohai Bay Basin and Ordos Basin are reported to have gas or oil shows or online, 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). PetroChina, Sinopec, Yanchang Petroleum also reported they have tapped shale gas and shale oil in Sichuan, Bohai Bay, Nanxiang and Songliao Basins, e.g., Sinopec was reported to tap the Jurassic Ziliujing lacustrine shale in Sichuan Basin and shale oil from Tertiary Nanxiang

Basin and Yanchang Petroleum announced the lacustrine shale from Triassic Yanchang Formation. Other recent positive exploration activities of China shale resources can be gathered from press releases and news report. The geologic settings of China shales and historical and recent drilling results demonstrated that China has huge shale resource potentials. Emerging Shale gas and shale oil plays show China will probably meet its scheduled plans that commercial shale gas production will start from 2015 and the goal of production capability from 10-15 leading shale gas fields will reach 15-30 Bcm (530-1060Bcf) in China in 2020.

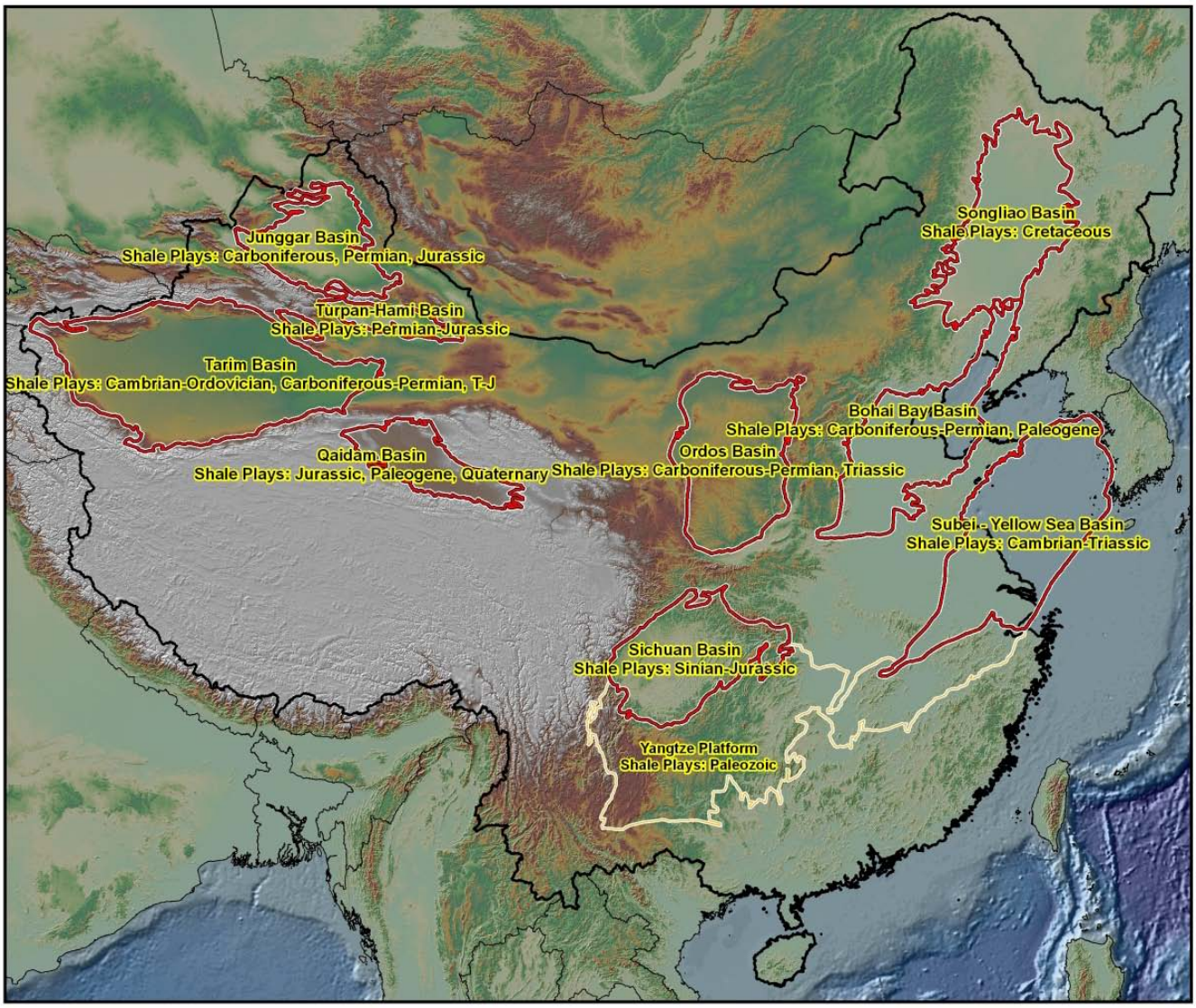

Figure 1. The potential China shale gas and shale oil plays, the scale is around 800 miles in length

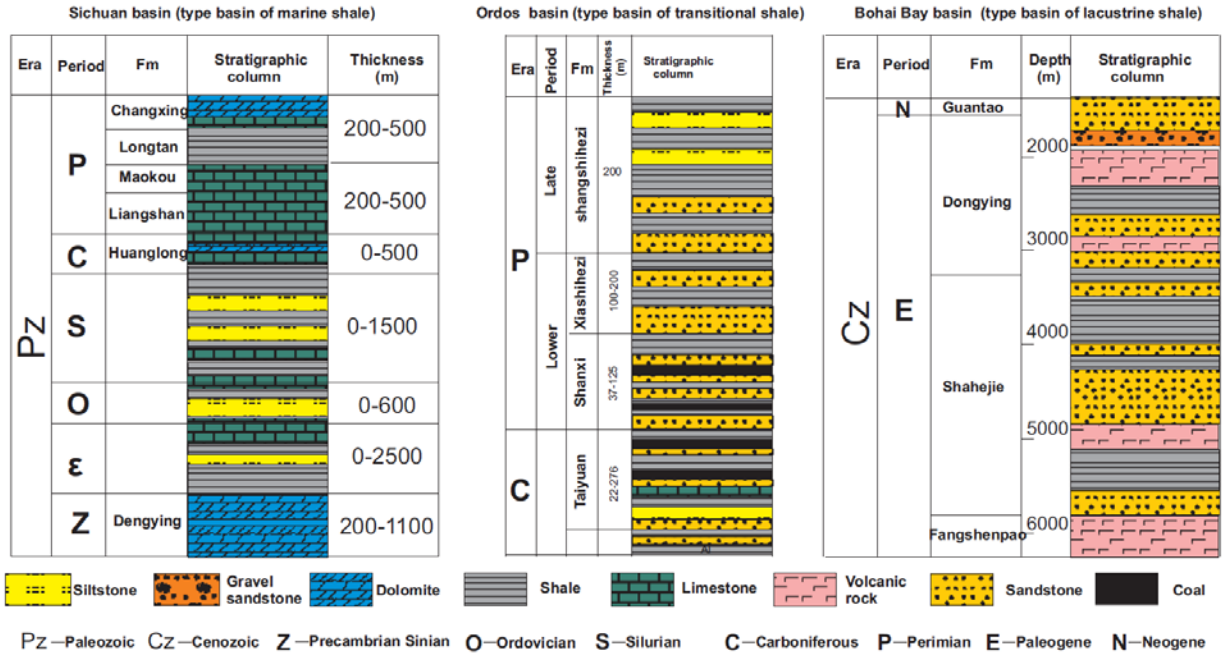

Figure 2 Three kinds of potential shales (marine, lacustrine and transitional/coastal setting) and their type basins

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

November 15-17, 2011: 3rd Annual Developing Unconventional Gas East Conference & Exhibition, Marcellus and More: Appalachian Shales, Pittsburgh, PA http://www.dugeast.com/

November 15-17, 2011: Canadian Unconventional Resources Conference, Calgary, Alberta, Canada. Canadian Society for Unconventional Gas and SPE International. http://www.spe.org/events/curc/2011/

November 28-December 1, 2011: ShaleGas World, Europe 2011, Warsaw, Poland. http://www.terrapinn.com/shalegas

December 4-6, 2011: Unconventional Resources: New Ideas for New Challenges – From Heavy Oil to Shale Gas/Shale Oil Opportunities, AAPG Geosciences Technology Workshop, Bogota, Colombia. http://www.aapg.org/gtw/bogota2011/index.cfm

January 11-13, 2012: Emerging North American Shale Plays, Denver, CO. Infocast. http://www.infocastinc.com/index.php/conference/569

January 24-26, 2012: Shale Gas & Tight Oil Argentina 2012, Buenos Aires. American Business Conferences. http://www.shale-gas-tight-oil-argentina.com

February 20-21. 2012: Applied Geoscience Mudrocks Conference, Houston, TX. Houston Geological Society. http://www.hgs.org/en/cev/1290.

March 15-16, 2012: Unconventional Hydrocarbon Plays in Asia, AAPG Geosciences Technology Workshop, Singapore. http://www.aapg.org/gtw/singapore2012/index.cfm

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

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/