EMD Shale Gas and Liquids Committee

2017 EMD Shale Gas and Liquids Committee Annual Report

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Executive Summary

Shale gas and liquids have been the focus of extensive drilling for the past 10+ years owing to improved engineering, recovery and abundance of reservoir. Although there is international interest in exploiting hydrocarbons from these unconventional reservoirs, with active exploration projects on most continents, much of the successful exploitation from shales continues to be in North America (Fig. 1), particularly in the United States but increasingly so in Canada and South America. While shale-gas production has been declining for the past years some areas saw a revival (e.g., Haynesville Shale) due to LNG facilities being built along the East Coast of the USA. However, shale-gas production remains low at 37,595 MCF/D in January 2017 and has been declining throughout 2016. Natural gas increase is only forecasted to increase slightly in the Marcellus and Permian Basin. New plays in shale liquids contributed to a reversal in oil production after a general decline over the last 20 years (e.g., Permian Basin). Although, shale-oil production remained strong at approximately 42,000 B/D due to improvements in drilling techniques, however daily production is forecasted to increase only in the Permian Basin in 2017 (EIA Dec. 2016, http://www.eia.gov/petroleum/drilling/pdf/dpr-full.pdf).

Overall, Europe remains relatively unexplored as compared to North America and many parts of Asia remain relatively unexplored for unconventional shale gas and oil, but interest in these plays is certainly high. South America's potential as unconventional shale gas and oil province is currently assessed in Argentina, but exploration and exploitation of these reservoirs and infrastructure are still in the development stages.

The following report provides the reader with information about many shale systems in North America that are actively being exploited for contained hydrocarbons as well as an overview of activities on many other continents.

Introduction

It is a pleasure to submit the Annual report from the EMD Shale Gas and Liquids Committee looking back to the year 2016. This report contains information about specific shales with recent activities in the US, Canada, Europe, and China. Given the intense interest in shales as "unconventional" hydrocarbon reservoirs, this report contains information available at the time of its compilation, and the reader is advised to use links provided herein to remain as up-to-date as possible.

This report is organized so that the reader can examine contributions from members of the EMD Shale Gas and Liquids Committee on various shales in the United States (presented in alphabetical order by shale name or region; Fig. 1), Canada, China, and Europe. Additional sections of the report include valuable links, Additional Sources of Information, and a Gas Shales and Shale Oil Calendar.

Please feel free to submit any comments or improvements to the committee chairs or contact Ursula Hammes (hammesu@gmail.com).

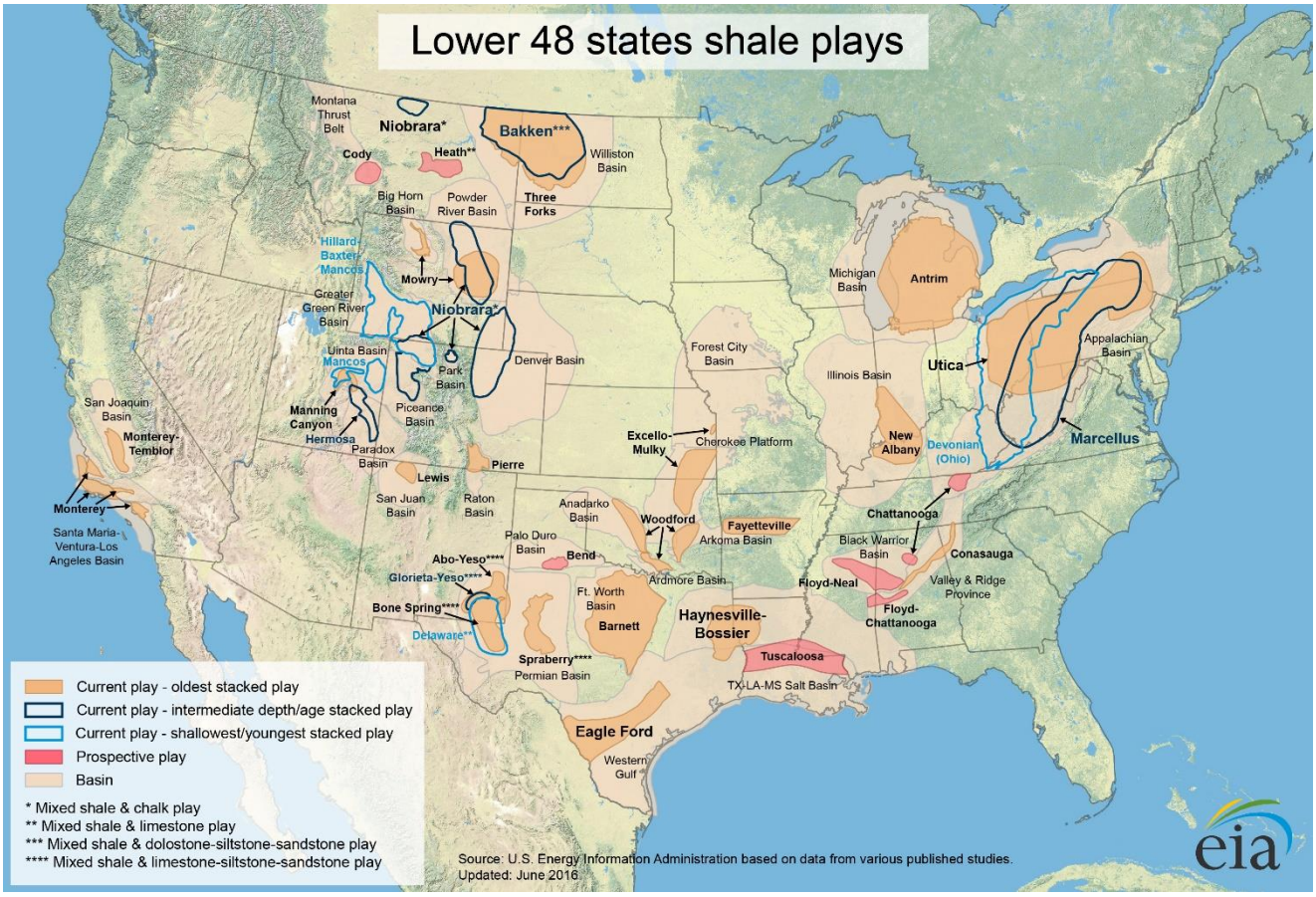


Figure 1: Current shale-gas and liquids unconventional plays in the Lower 48 States (EIA 2016)

The following reports are listed and linked respectively below in alphabetical order:

US SHALES

Antrim Shale

Bakken Shale

Barnett Shale

Eagle Ford Shale

Fayetteville Shale

Haynesville/Bossier Shale

Marcellus Shale

Niobrara Shale

Permian Basin, West Texas

Utah Shales

Utica Shale

Oklahoma shale gas/tight oil plays, U.S.A.

INTERNATIONAL SHALES

Canadian Shales

Chinese Shales

European Shales

GAS SHALES WEB LINKS

Status of U.S. ACTIVITIES

ANTRIM SHALE (DEVONIAN), MICHIGAN BASIN, U.S.

(originally reported 4/2013)

William B. Harrison, III (Western Michigan University)

The Michigan Basin Antrim Shale play is currently 25 years old, having begun the modern phase of development in 1987. The total number of producing wells drilled in the play through end of April, 2012 is approximately 11,500 with about 9,172 still online.

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 729 separate projects at the end of March, 2017. Cumulative production for first 6 months of 2016 was 43,077,089 MCF of gas. There were 29 operators with production at the end of March, 2017.

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 April, 2011 was 30 MCF/day per well. Many Michigan Antrim wells begin with high water production and begin to increase gas production as the water is pumped off. Water production generally continues throughout the project life, although it usually declines through time. Play wide gas to water production ratio reached almost 3 MCF/BBL in 1998, in 2004 it was 2.21 MCF/BBL, the 2009 ratio is 1.56 MCF/BB, the 2011 the ratio was 1.57 MCF/BBL and the ratio was 1.54 MCF/BBL through April, 2012. 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.

CO2 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% CO2 in the produced gas. The play wide average was just over 12.4% CO2 in 2008.

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

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

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

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

Significant Trends –Gas production has been in steady decline since 1996 (http://www.dleg.state.mi.us/mpsc/gas/pesec2.htm, accessed 11/2015).

MICHIGAN PUBLIC SERVICE COMMISSION

ANTRIM

2016

ANNUAL GAS PRODUCTION SUMMARY

MONTH	TOTAL MONTHLY GAS PRODUCTION (MCF)	TOTAL MONTHLY WATER PRODUCTION (BBL)	TOTAL NUMBER OF WELLS ONLINE	TOTAL NUMBER OF PROJECTS ONLINE	DAILY WELL PRODUCTION AVERAGES (MCFD/WELL)
January	7,446,207	3,893,020	9,181	737	26
February	6,902,724	3,575,333	9,171	736	25
March	7,329,848	3,836,038	9,089	728	26
April	7,038,609	3,591,916	9,120	729	25
May	7,268,442	3,659,847	9,166	731	25
June	7,091,259	3,625,057	9,172	729	25
ANNUAL TOTALS	43,077,089	22,181,211			

Figure 1: Monthly gas production summary from Michigan Public Service commission (accessed March 2017: http://www.dleg.state.mi.us/mpsc/gas/production/2016sum.pdf).

BAKKEN SHALE, WILLISTON BASIN, NORTH DAKOTA

Julie Lefever (deceased) and Stephan Nordeng (University of North Dakota)

Assessments performed by the United States Geological Survey (USGS) and the North Dakota Department of Mineral Resources in 2008 demonstrated that significant reserves were present in the Bakken Petroleum System in the entire Williston Basin (Pollastro and others, 2008; Bohrer and others, 2008; Nordeng and Helms, 2008).The area was re-assessed in 2013 due to an increase in the number of wells, longer production histories on existing wells, and new technologies and completion techniques (Gaswirth and Marra, 2015). Once again the assessment increased the undiscovered technically recoverable reserves to 3.65 billion barrels (bbls) for the Bakken and 3.73 billion bbls for the Three Forks formations of the U.S. Williston Basin.

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 1100 horizontal wells have been drilled in the 450-square-mile field from which more than 169 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 in 2004. Wireline logs of the Bakken Formation along the eastern portion of the Williston Basin in Mountrail County, North Dakota resembled those from Elm Coulee. The presence of free oil in DSTs and some minor Bakken production encouraged pursuit of the 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 the play gained prominence when EOG Resources drilled the #1-36 Parshall and #2-36 Parshall which resulted in wells with initial production rates in excess of 500 BOPD resulting in the discovery of Parshall Field.

Information obtained from extensive drilling in the state resulted in the definition of an additional member of the Bakken Formation called the Pronghorn. Additionally, the original members have been formalized to conform to the adjoining states and provinces. New standard subsurface reference sections have also been designated. The Bakken Formation now consists of four members, including: Upper; Middle; Lower; and Pronghorn.

Cores have played an important role in the understanding to this unconventional source system-play. There have been 167 cores cut on the North Dakota portion of the basin since the start of this play. Exploratory cores from the start of the play with extensive oils saturations have encouraged operators to drill, core, and produce from deeper portions of the source system. Production has been established from 3 separate horizons within the Three Forks Formation as well as the Middle Member of the Bakken. Thirty cores cut the complete Three Forks section adding to the understanding of a formation previously considered to be a trap.

Well stimulation of the early wells typically involved a large single stage fracture stimulation treatment using over 2 million pounds of proppant and over a million gallons of water. These single stage treatments have evolved into multistage treatments averaging 30 to 40 stages on the 10,000 ft laterals with a 50-50 split on plug and perf versus ball and sleeve (R. Suggs, 2015, Pers. Comm.). Fluid volumes range from 20,000 to 450,000 bbls with proppant amounts ranging from 80,000 to 3,500,000 lbs. Exceptions exist with laterals having 60 or more separate stages and proppant amounts as high as 10,000,000 lbs. The combination of horizontal drilling coupled with staged fracture stimulation has resulted in wells with IPs averaging in excess of 1100 BOPD per lateral.

Over 1.05 billion bbls of oil have been recovered from the 6665 wells in the 302 middle Bakken producing fields put into service since 2004. The 3503 horizontal wells drilled into the Three Forks Formation since 2006 have produced a total of 403 million bbls of oil. Currently there are 249 fields with Three Forks production. Seventy-seven wells have been completed in both the Bakken and Three Forks Formations. The majority of these wells were drilled in 2010.

After an all-time high of 218 rigs running on May 29, 2012, the rig count has decreased steadily with the drop in the price of oil. Fourty-nine rigs are currently running in the North Dakota portion of the Williston Basin. As of end of 2016 the following production stats were available from the North Dakota NDIC Department of Mineral Resources:

Oil Production December

- 29,211,993 barrels = 942,322 barrels/day
- January 30,389,117 barrels = 980,294 barrels/day(preliminary) (all-time high was Dec 2014 at 1,227,483 barrels/day)
- 932,818 barrels per day or 95% from Bakken and Three Forks
- 47,477 barrels per day or 5% from legacy conventional pools

Gas Production

- December 47,672,749 MCF = 1,537,831 MCF/day
- January 48,229,885 MCF = 1,555,803 MCF/day (preliminary) (all-time high was Nov 2016 at 1,759,524 MCF/day)

- Producing Wells December 13,337

Additional Information:

North Dakota Industrial Commission, Department of Mineral Resources, Oil and Gas Division Director's Cut: https://www.dmr.nd.gov/oilgas/informationcenter.asp

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

References:

Gaswirth, S.B. and K.R. Marra, 2015, U.S. Geological Survey 2013 assessment of undiscovered resources in the Bakken and Three Forks Formations of the U.S. Williston Basin province: AAPG Bull., v. 99, no. 4, p. 639-660.

Bohrer, M, Fried, S., Helms, L., Hicks, B., Juenker, B., McCusker, D., Anderson, F., LeFever, J., Murphy, E., and S. Nordeng, 2008, State of North Dakota Bakken Formation resource study project: https://www.dmr.nd.gov/ndgs/bakken/bakkenthree.asp

Durham, L., 2009, Experience paid off at Parshall, AAPG Explorer.

Pollastro, R. and others, 2008, Assessment of undiscovered oil resources in the Devonian-Mississippian Bakken Formation, Williston Basin province, Montana and North Dakota: USGS FS08-3021_508

Nordeng, S.H. and L.D. Helms, 2010, Bakken Source System: Three Forks Formation Assessment: https://www.dmr.nd.gov/ndgs/bakken/bakkenthree.asp

Sonnenberg, S.A., and A. Pramudito, 2009, Petroleum geology of the giant Elm Coulee Field, AAPG Bulletin, vol. 93, p. 1127-1153.

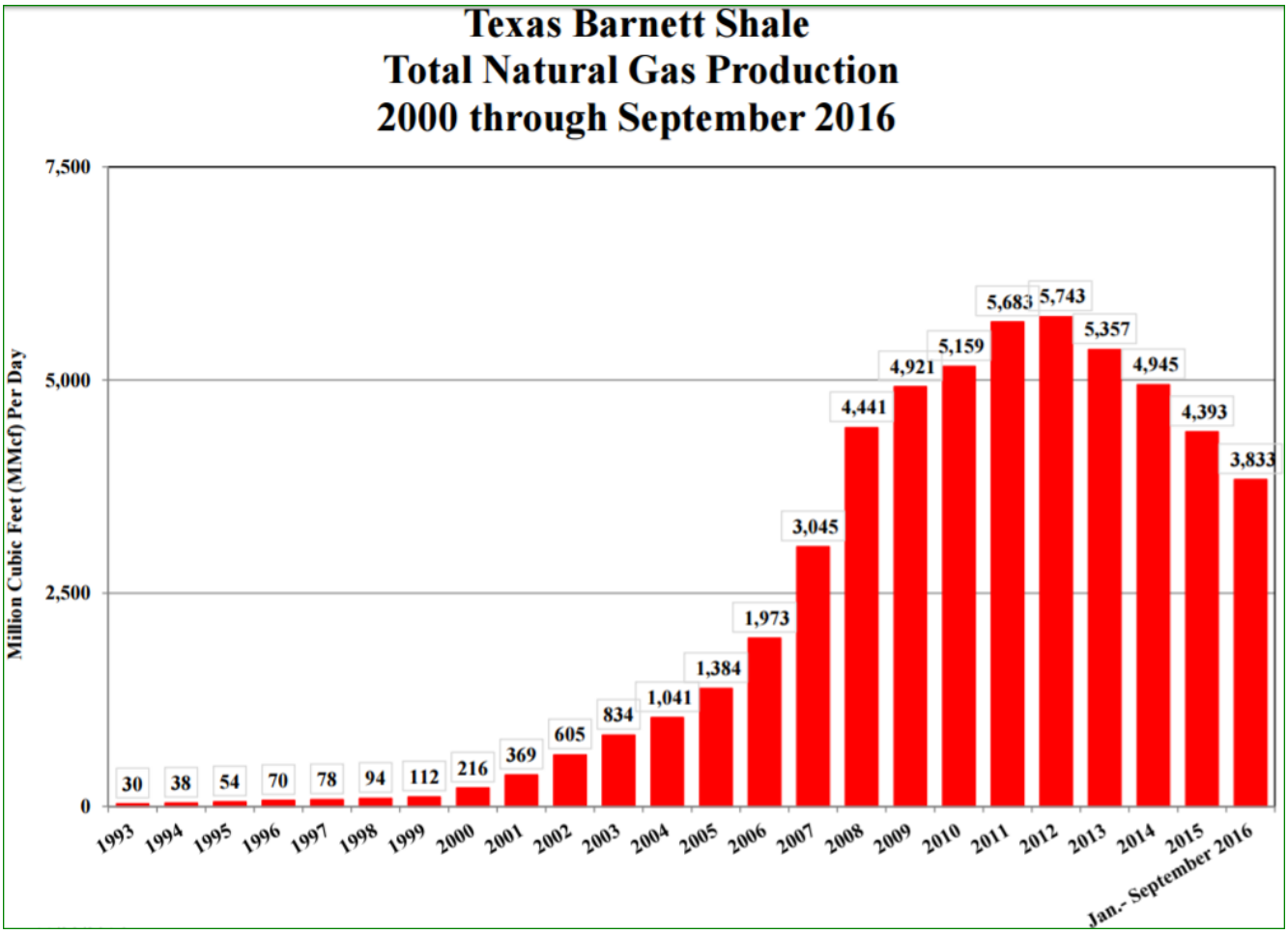
BARNETT SHALE (MISSISSIPPIAN), FORT WORTH BASIN, TEXAS

Kent A. Bowker (Bowker Petroleum, LLC)

Fort Worth Basin, Texas: Barnett Shale (Mississippian)

Kent A. Bowker (Bowker Petroleum, LLC)

Daily gas production from the Barnett Shale continues to decline and has now dropped an additional 50MMCFG/D since the Committee's April 2016 report. The current daily gas production is right at 3.8 BCF while oil/condensate production is at 9000 bbls.



http://www.rrc.state.tx.us/media/22204/barnettshale_totalnaturalgas_day.pdf

There are sixteen named Barnett fields in the Fort Worth basin, and as of January 2016 they have produced a total of 19.5 trillion cubic feet and gas and 66 million barrels of oil/condendsate (Texas Railroad Commission data).

The USGS has recently re-assessed the remaining resources in the Barnett (https://pubs.er.usgs.gov/publication/fs20153078). Total estimated mean volumes of 53 TCF of gas, 172 MMBO and 176 MMB of natural gas liquids were calculated by researchers at the USGS. This is the first USGS assessment that has included oil resources.

EAGLE FORD SHALE and TUSCALOOSA MARINE SHALE

Russell F. Dubiel (U.S. Geological Survey)

The Cretaceous (Cenomanian-Turonian) Eagle Ford Shale of southwest Texas continues to be an important play producing thermogenic gas, oil, and condensate. The Eagle Ford play trends across Texas from the area of the Maverick Basin, northeast through the Karnes Trough towards the East Texas Basin, where it is a target for dry gas, wet gas/condensate, or oil. From January to August 2015, Texas Eagle Ford oil production was more than 1 MMBO per day, and natural gas production was more than 5 BCFG per day (http://www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/eagle-ford-shale/), making it perhaps the largest oil producing play in the US. Completed wells display a steady decline in production similar to those in other shale plays. Recently drilled shale oil wells have shown initial production rates of several hundred to as much as 1,000 barrels of oil per day (BOPD). As of October 2015, there were more than 9,300 oil

wells and more than 4,600 gas wells in the Eagle Ford Shale in southwest Texas (http://www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/eagle-ford-shale/). The trend occurs at an average depth of 11,000 feet.

Similar to other shale oil producing units in the US, the Eagle Ford is a viable target for hydrocarbon exploitation because of advances in the application of horizontal drilling and hydraulic fracturing. Lithology of the Eagle Ford is somewhat different than other gas shales, however, in that where it is being explored, the Eagle Ford contains significant marlstone and limestone beds that are brittle and enhance the opportunity for induced fractures. Most operators are drilling horizontal well laterals of 3,500 to more than 5,000 feet and are stimulating the wells with slick water or acid in at least 10 different fracture stages. For more information on Eagle Ford production, please refer to the Texas Railroad Commission web site (http://www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/eagle-ford-shale/).

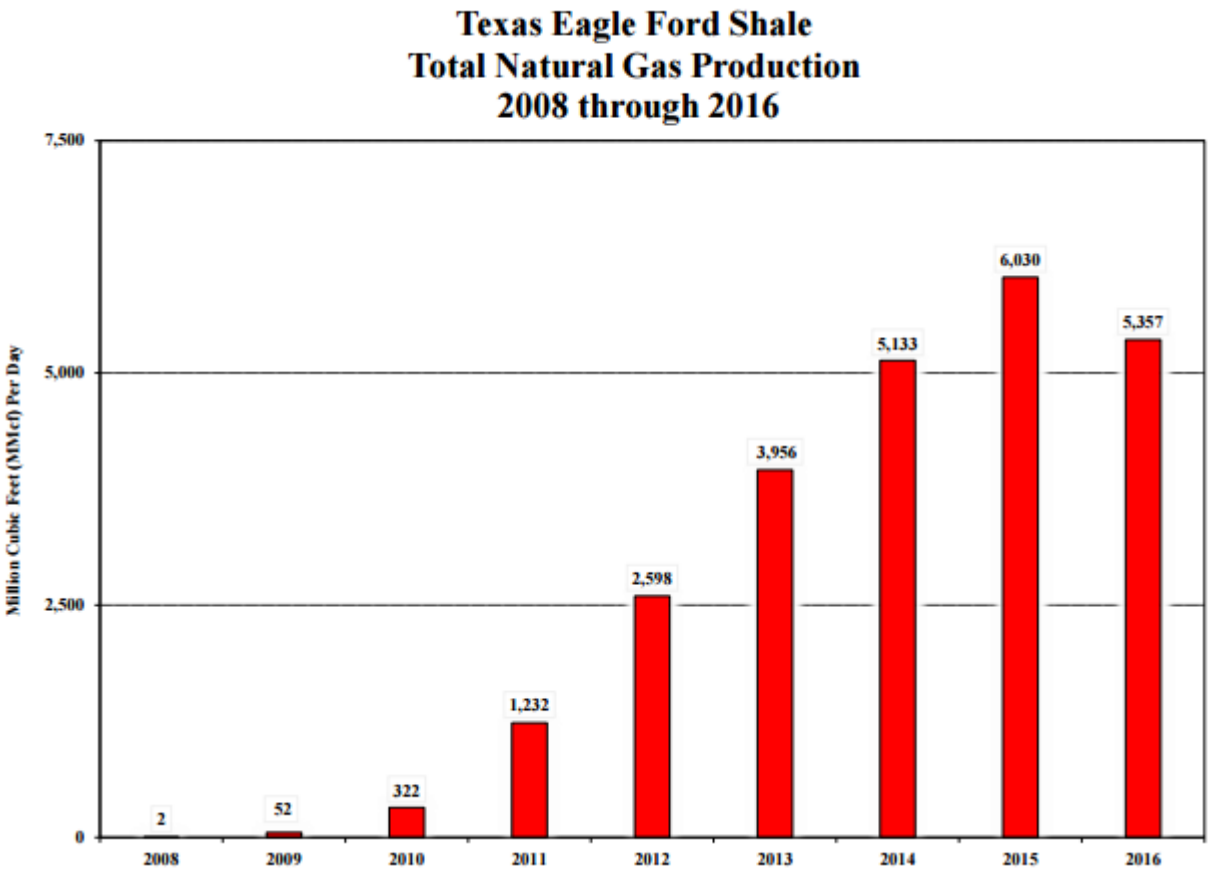
The industry term "Eaglebine" has been used locally for that part of the Eagle Ford Shale that interfingers with Woodbine Group sandstones in the northeast extension of the play south of the East Texas Basin. Adams et al. (2014), however, provide convincing arguments for the extension and application of formal stratigraphic nomenclature that has historical precedence, such as the Eagle Ford and Woodbine, to the extension of the Eagle Ford Shale northeast of the San Marcos arch and the Woodbine in the area south of the East Texas Basin.

Activity and success in the Eagle Ford Shale in Texas has generated renewed interest in the laterally equivalent Cenomanian-Turonian strata of the Tuscaloosa marine shale in eastern Louisiana and southern Mississippi. Initial exploration in the Tuscaloosa marine shale in the 1970's has been followed by minimal exploration and production in the 1980's, 1990's and early 2000's. Since 2010, several companies have begun significant leasing in eastern Louisiana and southern Mississippi. Over the last five years, those companies have begun exploration and initial development drilling in the Tuscaloosa marine shale. This activity is based in part on the historical record of hydrocarbon generation and proven, but minimal, oil production from the unit, the temporary high price for oil, corresponding low price for natural gas, and the significant success of horizontal drilling in the Eagle Ford in Texas. The Tuscaloosa marine shale trend averages about 12,000 to 15,000 feet in depth in the region north of the Lower Cretaceous shelf edge. South of the Lower Cretaceous shelf edge, the clastic shelf-margin deltas and laterally equivalent marine shales of the lower Tuscaloosa extend to more than 25,000 feet. Since 2010, several companies have drilled successful horizontal wells in Louisiana and southern Mississippi north of the Lower Cretaceous shelf edge, with about 45 wells currently producing oil in eastern Louisiana and southern Mississippi (http://dnr.louisiana.gov/; http://www.sonris.com/). This production trend is comparable to the approximately 40 wells that were current in the Eagle Ford in early 2009 (http://www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/eagle-ford-shale/). Reported IPs are encouraging, in the neighborhood of several hundred BOPD, but currently only minimal yearly production data is available to evaluate the Tuscaloosa marine shale future success.

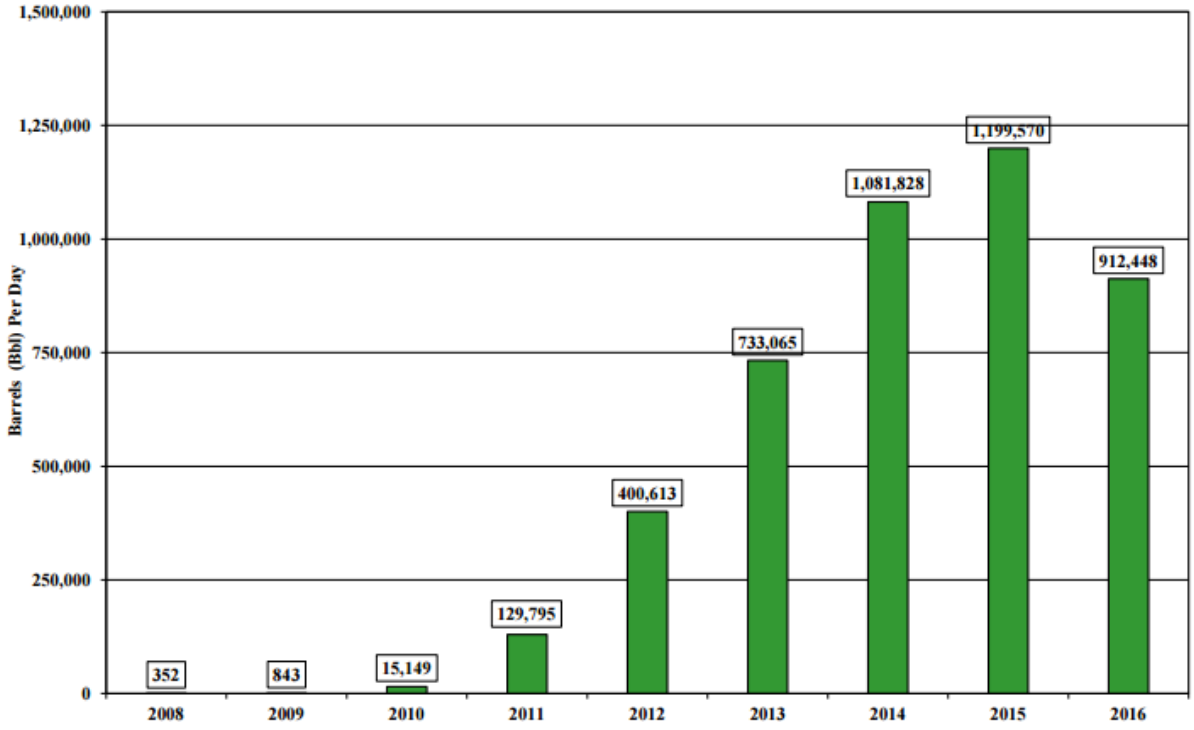
The marine source rocks of the Eagle Ford and Tuscaloosa have total organic carbon (TOC) contents as high as 5 to 6%. Thermal modeling based on vitrinite reflectance identifies an oil generation window that trends subparallel to the Lower Cretaceous shelf edge, with an adjacent gas generation window downdip and deeper toward the modern coast. Recent studies indicate that the source rock interval in the Eagle Ford Shale in the Maverick Basin area and northeast to the San Marcos arch of southwest Texas lies in the lower part of the Cenomanian section, rather than in the Turonian strata (Donovan and Staerker, 2010; Donovan et al., 2012). Stratigraphic correlation of the Cenomanian and Turonian section of the Eagle Ford Shale in

southwest Texas to Louisiana and Mississippi indicates that the Tuscaloosa marine shale currently being drilled north of the Lower Cretaceous shelf edge may be entirely upper Cenomanian and Turonian in age. The corresponding lower Cenomanian strata would lay south of the Lower Cretaceous shelf edge, distal to the Cenomanian shelf-margin delta sandstones of the lower Tuscaloosa, and within the gas window (Dubiel and Pitman, 2003, 2004).

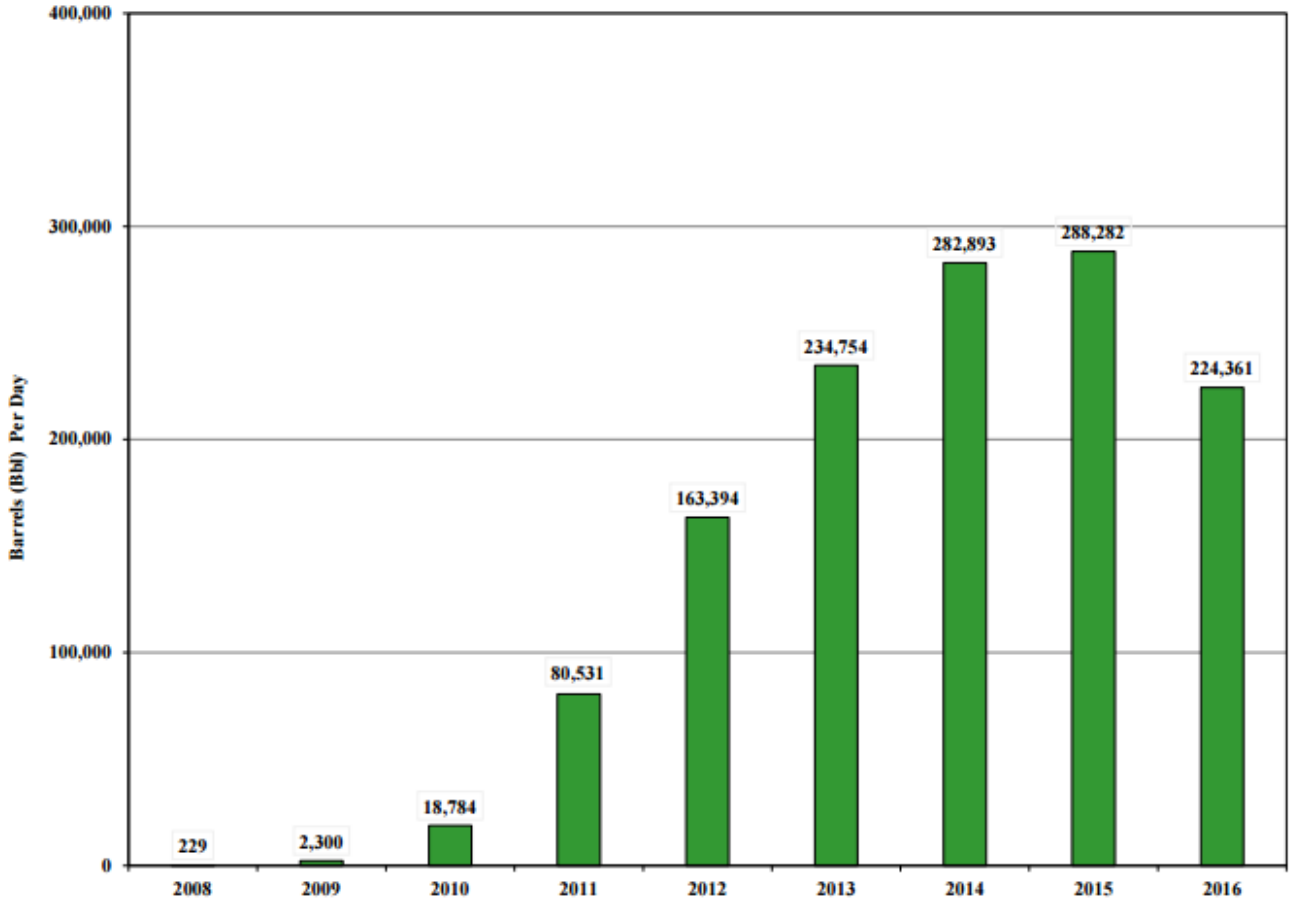
Please find below yearly gas, oil, and condensate production from Railroad Commission of Texas:



Texas Eagle Ford Shale
Oil Production
2008 through 2016



Texas Eagle Ford Shale
Condensate Production
2008 through 2016



References:

Adams, R.L., Carr, J.P., and Ward, J.A., 2014, The lower Woodbine organic shale of Burleson and Brazos Counties, Texas: Gulf Coast Assoc. Geol. Soc. Trans., v. 64, p. 3-31.

Donovan, A.D., Staerker, T.S., 2010, Sequence stratigraphy of the Eagle Ford (Boquillas) formation in the subsurface of south Texas and the outcrops of west Texas: Gulf Coast Assoc. Geol. Soc. Trans., v. 60, p. 861–899.

Donovan, A.D., Staerker, T.S., Pramudito, A., Li, W., Corbett, M.J., Lowery, C.M. Miceli, Romero, A., Gardner, R.D., 2012, The Eagle Ford outcrops of west Texas: a laboratory for understanding heterogeneities within unconventional mudstone reservoirs: Gulf Coast Assoc. Geol. Soc., Journal, v. 1, p. 162–185.

Dubiel, R.F., Pitman, J.K., and Steinshouer, D., 2003, Seismic sequence stratigraphy and petroleum system modeling of the downdip Tuscaloosa-Woodbine trend, Louisiana and Texas, in Dutton, S.P., Ruppel, S.C., and Hentz, T.F., eds., Transactions of the Gulf Coast Association of Geological Societies, and Gulf Coast Section – SEPM, v. 53, p. 193-203.

Dubiel, R.F., and Pitman, J.K., 2004, Analysis of the Tuscaloosa-Woodbine Total Petroleum System and implications for assessing conventional gas resources in the downdip trend, *in* Jones, W.E., Smith, R., and Willetts, eds., Transactions of the Gulf Coast Association of Geological Societies, and Gulf Coast Section - SEPM, v. 53, p. 153-158.

FAYETTEVILLE SHALE, ARKOMA BASIN, ARKANSAS

Peng Li, Arkansas Geological Survey (December 30, 2016)

Arkansas Fayetteville Shale Gas Play

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.

U.S. Energy Information Administration (EIA) reports in 2013 that the Fayetteville contains 31.96 Tcf of technically recoverable gas resource, in which 27.32 Tcf is attributable to the core producing area (aka eastern area) and 4.64 Tcf for the uncore producing area (aka western area). A study by the Bureau of Economic Geology at the University of Texas at Austin found the play holds 38 Tcf in technically recoverable resources, of which a cumulative 18.2 Tcf is economically recoverable reserves by 2050 (OGJ, 2014). EIA also reports that the proved gas reserves of the Fayetteville Shale in 2013 is 12.2 Tcf, an increase over the 2012 estimate of 9.7 Tcf. Estimated ultimate recovery (EUR) for a typical horizontal Fayetteville gas well decreases from 3.2 Bcf in 2011 to 3 Bcf in 2013 (OGJ, 2014).

According to the Arkansas Oil and Gas Commission (AOGS) data, estimated cumulative production of gas from the Fayetteville Shale as of the September 2016 has totaled 7.17 Tcf from 5,875 wells. For the first nine months of 2016, 571,217,588 Mcf of gas produced from 5,488 wells in the play. Initial production rates of horizontal wells in 2016 averaged about 6.0 MMcf/day. For more Fayetteville Shale production information, please refer to the AOGC web link at http://www.aogc.state.ar.us/Fayprodinfo.htm.

After pulling two gas drilling rigs during the last week of 2015, SEECO (SWN) returned a rig to work in Fayetteville Shale over the summer of 2016 as natural gas futures bounced around $3 per MMBtu. Since then, only 2 wells were spudded in the play. 32 wells were completed by SEECO in 2016, an 88% decline compared to 266 completion wells a year ago.

Most Fayetteville Shale wells are drilled horizontally and have been fracture stimulated using slickwater or cross-linked gel fluids. Baker Hughes' FracPoint Multi-stage fracturing system has provided most of the hydraulic fracturing completions in the Fayetteville Shale. 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).

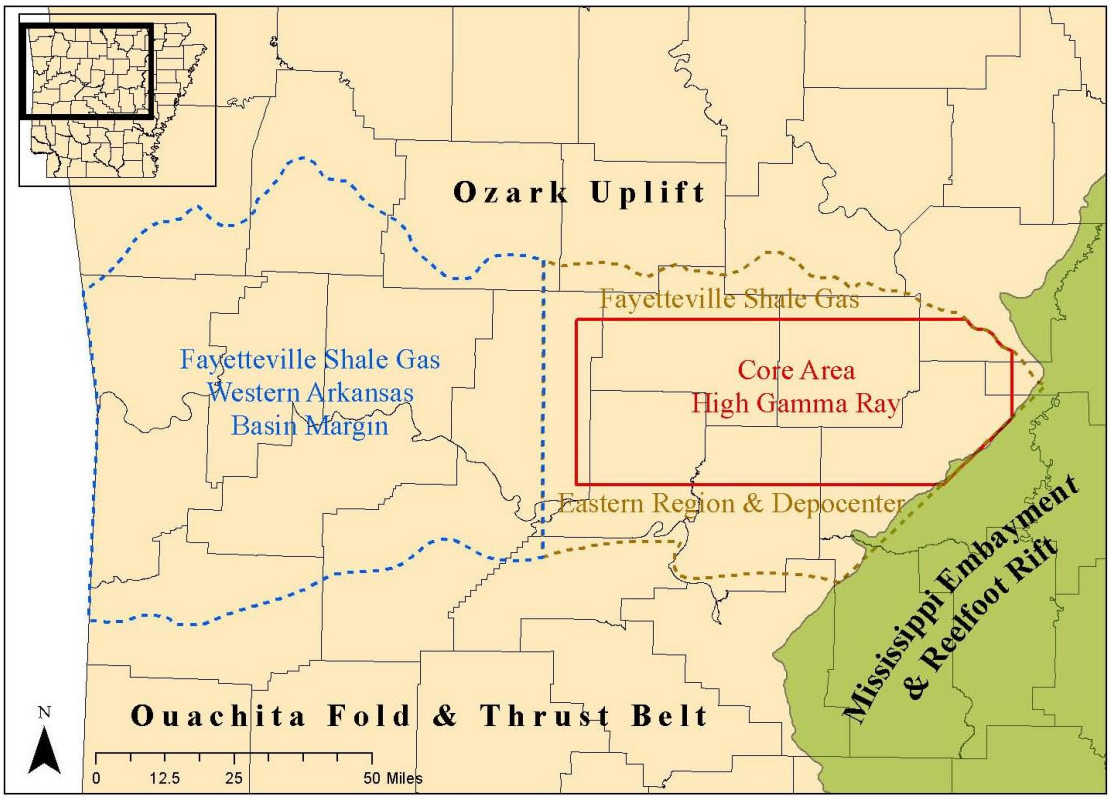


Figure 1. Primary area of the Fayetteville Shale exploration and development in Arkansas.

Since the play's inception, the Fayetteville Shale play has been dominated by a small number of large players. Three operators – Southwestern Energy, BHP Billiton, and XTO Energy (a subsidiary of Exxon Mobil) – accounted for over 99% of gross operated production from the field. The three companies hold close to 2 million net acres under lease in the play. Southwestern, with 888,161 net acres and more than three thousand producing wells, is by far the largest operator among the three companies, and accounts for about two-thirds of the field's total production volume. Exxon and BHP are approximately equal in terms of their acreage and gross operated production. For the first nine months of 2016, Southwestern contributed 430 Bcf in Fayetteville gas sales, good for 75.1% of the play's total sales that year. XTO Energy sold 73 Bcf (12.8%) and BHP traded 68 Bcf (11.9%). The remaining 0.2 % of sales, or 1.4 Bcf, was spread out among eight companies.

The top three operators of the Fayetteville gas shale play as of September 2016 based on numbers of producing wells are as follows (Figure 2):

1) SEECO Inc. (an exploration subsidiary of Southwestern Energy) (3,928 wells)

2) BHP Billiton Petroleum (980 wells)

3) XTO Energy, Inc. (a subsidiary of ExxonMobil) (888 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.

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

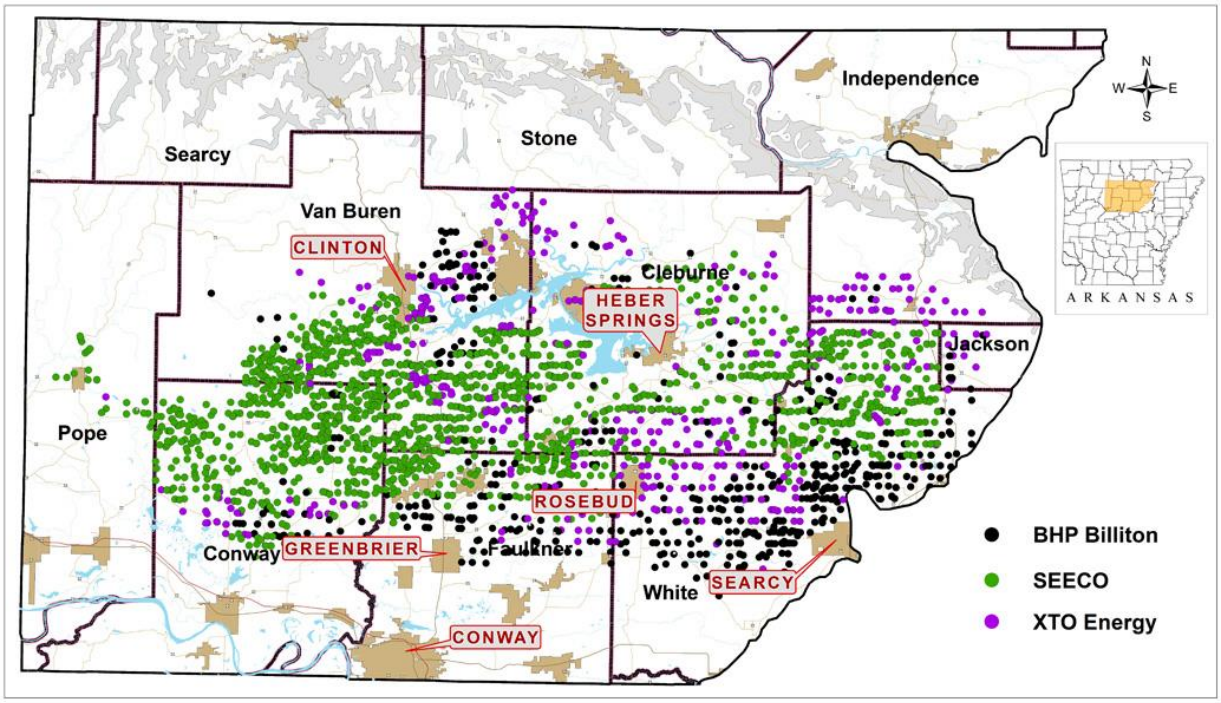


Figure 2. Location map of the Fayetteville Shale producing wells by top 3 operators as of March 2016.

Disposal of production well wastewater through injection wells has gradually mounted concern in the Fayetteville Shale play area given thousands of recent area earthquakes. Most of the seismic events have been too small to be felt, and a majority of the epicenters form a northeast-southwest trending linear feature near the towns of Guy and Greenbrier in Faulkner County. These earthquakes have become known as the Guy-Greenbrier Swarm. It was recently discovered that the Guy-Greenbrier Swarm earthquakes occurred along and illuminate a previously unknown sub-surface fault, the Guy-Greenbrier Fault, located near the disposal wells. The fault, nearly 7.5 miles long, could theoretically generate an earthquake of around 6.0 in magnitude. In January 2011, the AOGC imposed a six-month moratorium on new injection wells in a portion of the Fayetteville Shale production area to determine what relationship, if any, there is between the wastewater injection and the earthquakes. The quakes intensified during the last two weeks of February 2011, culminating with a 4.7-magnitude earthquake near Greenbrier on February 27, 2011, the most powerful reported seismic event in Arkansas in 35 years. AOGC held a special meeting on March 4, 2011 to issue an emergency order immediately shutting down all injection operations of two disposal wells through the last day of the regularly scheduled hearing in March 2011. At the March 2011 hearing, AOGC ordered the companies to continue the cessation of all injection operations of these two wells for a period of an additional sixty days. During the July 2011 hearing, the AOGC requested an immediate and permanent moratorium on

any new or additional disposal wells or disposal well permits in the moratorium area (Figure 3). At the time of the hearing, there were four disposal wells within the moratorium area, including the two wells that were shut down since March 2011. The frequency of the quakes within the moratorium area saw a significant decrease, about 75%, since the cessation of the injection operation of the disposal wells. This, in turn, gave more evidence to confirm a potential 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.

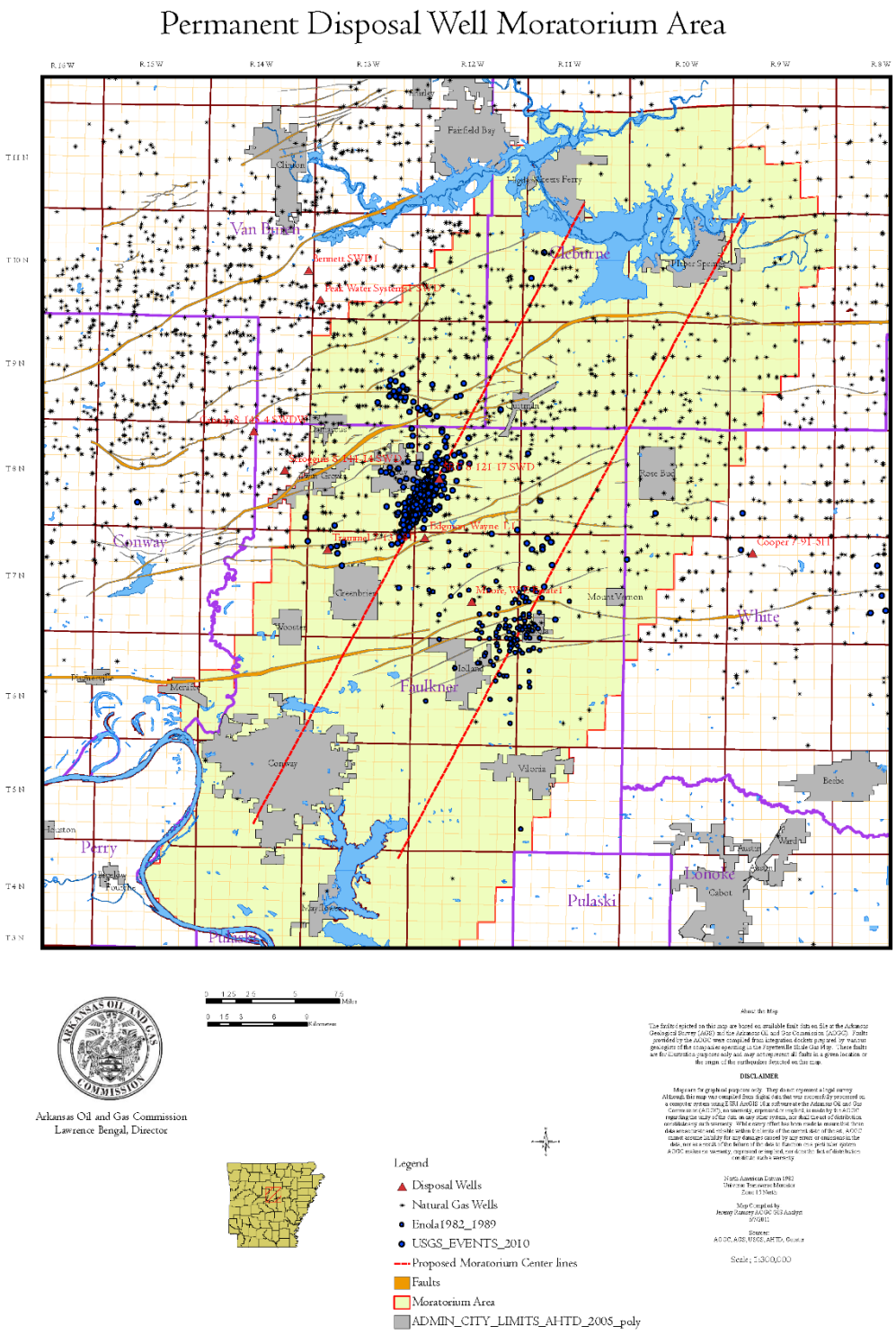


Figure 3. Permanent moratorium area for disposal wells in the Fayetteville Shale Play, Arkansas (from the AOGC website).

References

Li, P., M.E. Ratchford, and D.M. Jarvie, 2010, Geochemistry and thermal maturity analysis of the Fayetteville Shale and Chattanooga Shale in the western Arkoma Basin of Arkansas: Arkansas Geological Survey Information Circular 40, 191p.

Ratchford, M.E., Bridges, L.C., Dow, W.G., Colbert, A., and Jarvie, D. M., 2006, Organic geochemistry and thermal maturation analysis within the Fayetteville Shale study area – Eastern Arkoma basin and Mississippi Embayment regions Arkansas, Arkansas Geological Survey, Information Circular 37, pp.200, 23 Map Plates.

HAYNESVILLE/BOSSIER SHALES, EAST TEXAS BASIN, TEXAS

Ursula Hammes (Hammes Energy & Consultants, LLC, Austin, TX)

The Haynesville and Bossier Shales has been one of the most prolific gas producers of the North American shale plays because of high pressure, high TOC, and brittle/frackable lithologies (e.g., Hammes et al., 2011; Wang et al., 2013), However, because of its depth (most sweetspot wells >12,000ft TVD) and persistently low gas prices, production has been steadily declining. Nevertheless, the Haynesville Shale in Texas and Louisiana is starting to experience a slight revival due to construction of LNG and gas-power plants being built along the TX Gulf coast. One of the advantages of the Haynesville shale gas is that it is dry gas and will not have to be processed before being liquefied. New technologies learned from other shale plays might also assist in additional production as well as refracking of 5-6 year old wells drilled in the early phase of the play. Haynesville drilling permits and rig counts have been in a steady decline since the peak of 2012 but showed a slight increase late 2016/early 2017 (Figs. 1, 2). That might be related to construction of LNG and gas-power plants being built along the TX Gulf coast that utilize Haynesville Shale gas. One of the advantages of the Haynesville shale gas is that it is dry gas and will not have to be processed before being liquefied. New technologies learned from other shale plays might also assist in additional production as well as refracing of 5-6 year old wells drilled in the early phase of the play which is evident in the increase in production coupled with a decrease in drill rig counts. Production fell to about half from what was produced at its peak in 2012 but showed a slight increase at the beginning of 2017 (Fig. 3). Additional information on the Haynesville can be found at the Louisiana Oil and Gas association http://dnr.louisiana.gov/index.cfm?md=pagebuilder&tmp=home&pid=442 and from the Texas Railroad Commission http://www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/haynesvillebossier-shale/

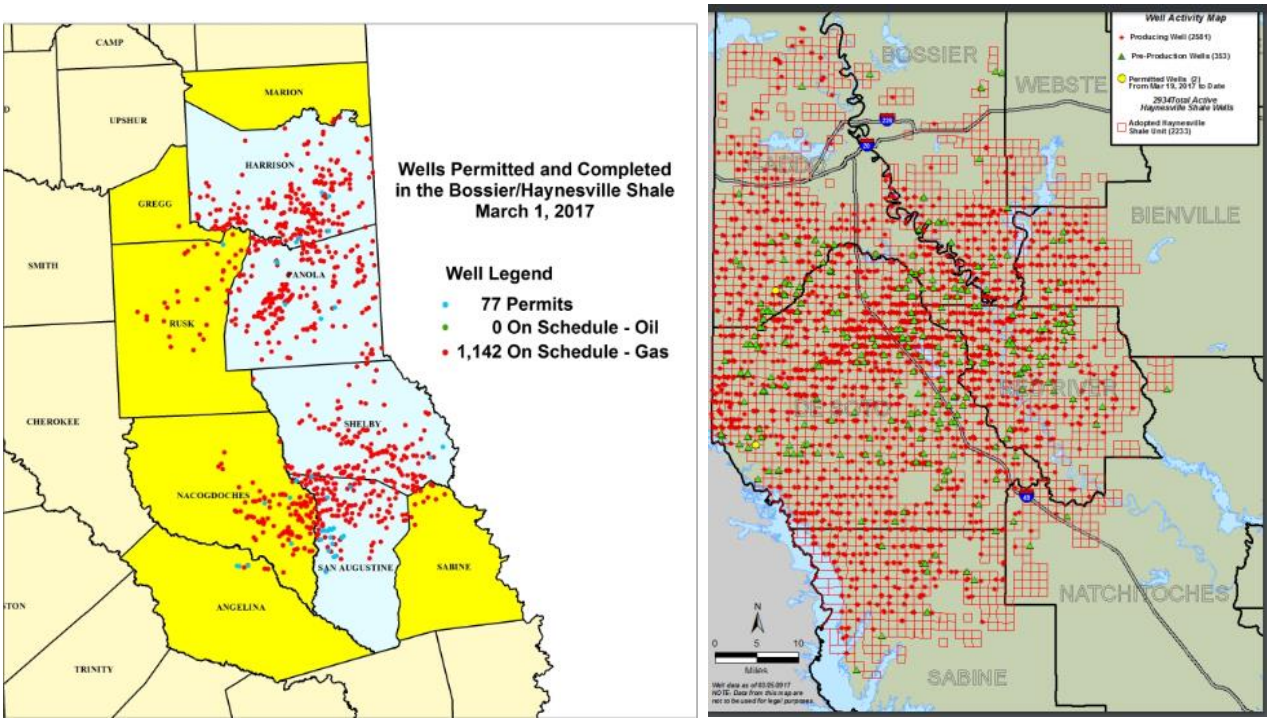


Figure 1: Wells permitted and complete in Texas (left) and Louisiana (right) Haynesville/Bossier trend by March 27, 2017 (RRC and DNR LA, March 2017).

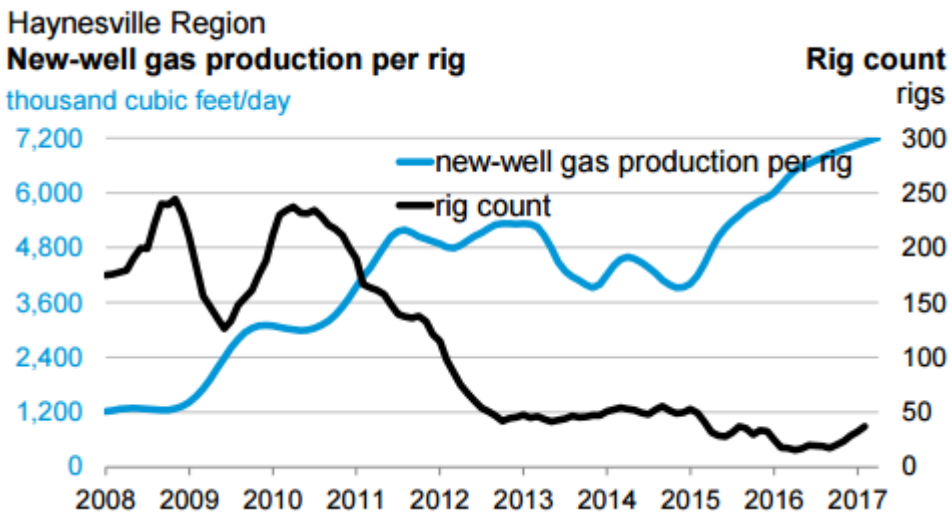


Figure 2: Haynesville rig count and new-well gas production per rig through first quarter 2017 (from EIA productivity report - https://www.eia.gov/petroleum/drilling/pdf/dpr-full.pdf). Note that production per rig has been increasing despite declining rig count!

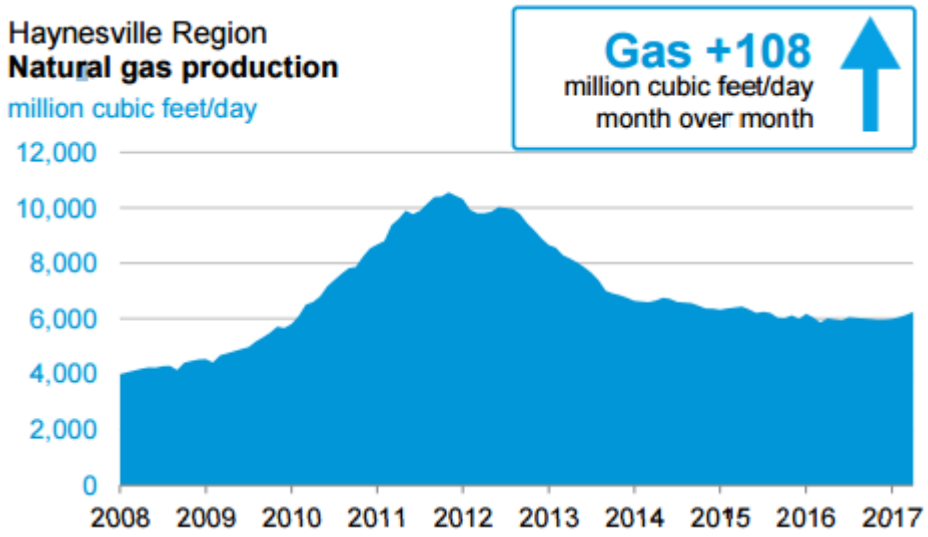


Figure 3: Daily gas production (in MMcf) through February 2017 of the Haynesville Shale (data from www.eia.gov, accessed March 2017).

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Hammes, U., H.S. Hamlin, and T.E. Ewing, 2011, Geologic analysis of the Upper Jurassic Haynesville Shale in east Texas and west Louisiana: AAPG Bull., v. 95, p. 1643-1666.

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MARCELLUS SHALE, APPALACHIAN BASIN, U.S.A.

Catherine Enomoto (U.S. Geological Survey, Reston, VA), December 2016

The Middle Devonian Marcellus Shale of the Appalachian Basin is the most extensive shale play in the U.S., covering about 66,600,000 acres (USGS Marcellus Shale Assessment Team, 2011). Extending from Tennessee to New York, the gross thickness of the Marcellus Shale increases to the northeast, with the thickest area located in northeastern Pennsylvania (Milici and Swezey, 2006; Wrightstone, 2009). The organic-rich zone of the Marcellus Shale has a net thickness of 50 to over 250 feet, and exists at drilling depths of 2,000 to 9,000 feet ((Milici and Swezey, 2006; Wrightstone, 2009). The organic-rich Marcellus Shale has high radioactivity responses, and thus high gamma ray values on well logs, because the organic matter tends to concentrate uranium ions (Harper, 2008). According to 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. As reported in Milici and Swezey (2006), Repetski and others (2008), and Ryder and others (2013), analyzed samples of the Marcellus Shale had mean random vitrinite reflectance values between 1.0 and

2.5% in the majority of the currently productive area, where most production has been natural gas. However, in southwest Pennsylvania, eastern Ohio, and northern West Virginia, reported production included condensate and oil from wells in the Marcellus Shale. Published data indicates the total organic carbon content (TOC) of the Marcellus Shale is as high as 11% (Repetski and others, 2008).

As in other shale plays, horizontal drilling and hydraulic fracturing increase production rates of petroleum, which improves the commerciality of hydrocarbon production from this formation. The orientation of the horizontal sections of the wells and the design of the staged hydraulic fracturing operations enhance the natural fracture trends in the Marcellus Shale. "Slick-water fracs" have provided the best method for recovering large volumes of natural gas efficiently. These use sand as a proppant and large volumes of freshwater that have been treated with a friction reducer such as a gel. The slick-water frac maximizes the length of the induced fractures horizontally while minimizing the vertical fracture height (Harper, 2008). Water supply for large volume fracturing is a concern, as are the potential environmental impacts related to handling and management of produced formation water and used hydraulic fracturing fluid, called "flow-back" fluid (Engle and Rowan, 2014; Skalak and others, 2014; Capo and others, 2014). The management of produced formation water and used hydraulic fracturing fluid have been addressed with a variety of approaches including 1) treatment followed by discharge into receiving basins or streams, 2) injection into subsurface disposal wells, or 3) treatment to remove solids and unwanted contaminants followed by reuse.

According to a report published by the U.S. Energy Information Administration (EIA) in October, 2015 (U.S. Energy Information Administration, 2015a), which contained analyses of drilling and production data through September, 2015, the number of rigs that completed wells in the Marcellus Shale decreased by about 50% from January 1, 2012, to September, 2015. However, the new-well gas production per rig in the Marcellus Shale region (which includes production from overlying and underlying formations (U.S. Energy Information Administration, 2015b)) increased from 3.2 million cubic feet (Mcf) per day in January, 2012, to 8.7 Mcf per day in September, 2015. The production from the Marcellus Shale region was about 16.5 billion cubic feet (bcf) of gas per day and about 60,000 barrels (bbls) of oil and condensate per day, in July, 2015, according to the EIA (U.S. Energy Information Administration, 2015b).

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" (Coleman and others, 2011). According to this 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 bbls in continuous-type accumulations in the Marcellus Shale. The estimate of natural gas resources ranged from 43 to 144 tcf (95 percent to 5 percent probability, respectively), and the estimate of natural gas liquids (NGL) resources ranged from 1.6 to 6.2 billion bbls (95 percent to 5 percent probability, respectively). This re-assessment of the undiscovered continuous resources in the Marcellus Shale updated the previous assessment of undiscovered oil and gas resources in the Appalachian Basin performed by the USGS in 2002 (Milici and others, 2003), which estimated a mean of about 2 tcf of natural gas and 11.5 million bbls of NGL in 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. In Figure 1, the extent of three assessment units (AU) defined in this latest assessment are shown. Ninety-six percent of the estimated resources reside in the Interior Marcellus AU.

The increase in undiscovered, technically recoverable resources is due to new geologic information and engineering data. In late 2004, the Marcellus Shale was recognized as a potential reservoir rock, instead of only a regional hydrocarbon source rock. Technological improvements resulted in improved commerciality of gas production from the Marcellus Shale,

and caused rapid development of this new play in the Appalachian Basin, the oldest producing petroleum province in the United States. According to the Pennsylvania Department of Conservation and Natural Resources, the first horizontal wells in the Marcellus Shale were drilled in 2006. Natural gas production was reported from horizontal wells that were completed in the Marcellus Shale in West Virginia as early as 2007.

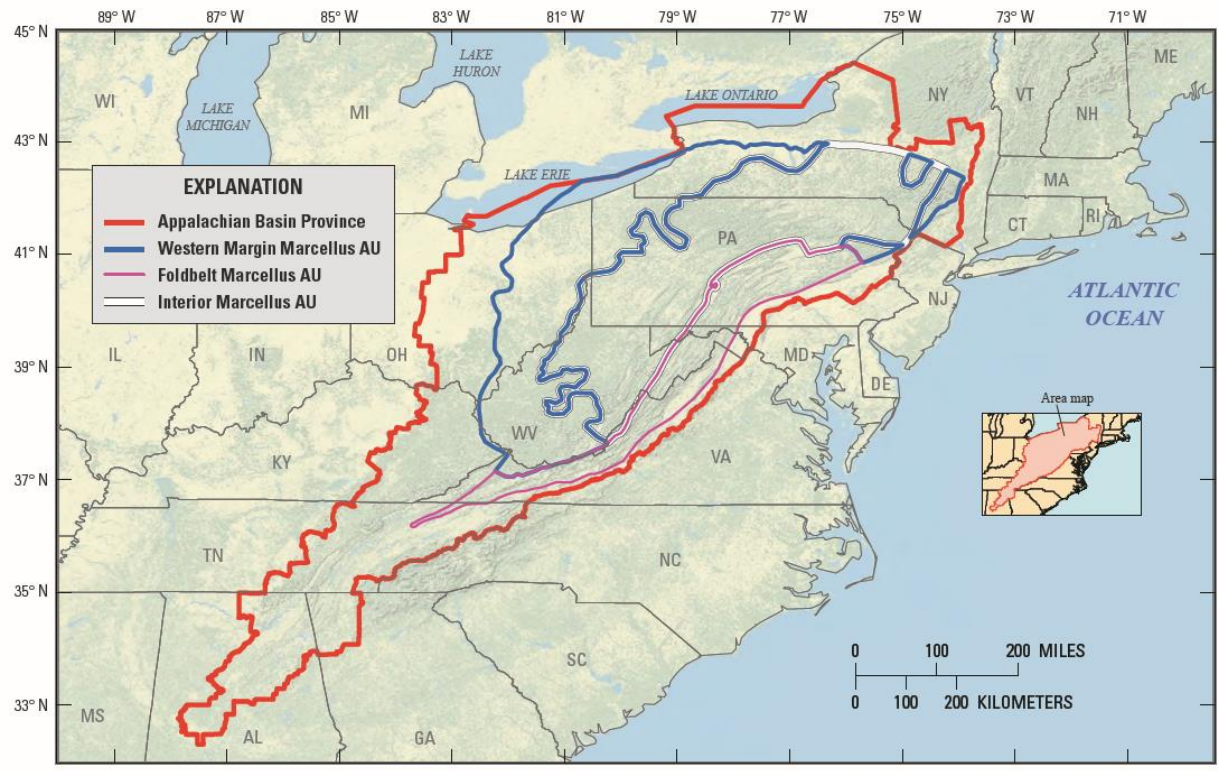

Figure 1. Map of the Appalachian Basin Province showing the three Marcellus Shale assessment units (Coleman and others, 2011).

Maryland: According to the Maryland Geological Survey (MGS), the Marcellus Shale is present in Garrett and Allegany counties in western Maryland, where its thickness is 150 to 250 feet. The depth of the Marcellus Shale in western Maryland is zero to more than 8,000 feet. Although natural gas production is not available online, it is believed that there were no exploration wells drilled in Maryland between 1996 and 2016. There is currently (2016) no reported production from the Marcellus Shale in Maryland. Due to the estimated thermal maturity of the Marcellus Shale in Maryland (Repetski and others, 2008), it is likely that dry gas will be found if wells are drilled and completed in the Marcellus Shale. Oil and gas exploration and production regulations were published in the November 14, 2016, edition of the Maryland Register. (http://mde.maryland.gov/programs/Land/mining/marcellus/Pages/index.aspx)

The regulatory proposal is open for public comment through December 14, 2016. According to the Maryland Department of the Environment (MDE), the regulations may not become effective, nor may a permit be issued for a horizontal well that will utilize hydraulic fracturing, until October 1, 2017.

New York: The Marcellus Shale extends into the northernmost part of the Appalachian basin in central New York. The organic-rich thickness of the Marcellus Shale increases from 20 feet in the west to 250 feet in the eastern part of the basin in New York (Smith and Leone, 2010). The depths of the Marcellus Shale range from zero to as much as 7,000 feet in the eastern part of the basin in south-central New York (Smith and Leone, 2010). According to the New York State Department of Environmental Conservation (DEC), 50 vertical wells have been drilled that reported Marcellus Shale as a producing formation. Of those, 27 are plugged and abandoned, 8 are shut-in or inactive, 3 are "not reported on AWR", and 12 are active. Production was reported for 12 wells in 2015 (most recent data available). Natural gas production from the Marcellus Shale in 2015 was about 12 Mcf, down from the high of 64 Mcf reported for 2008. There was no reported oil production. In 2015, most of the productive wells were located in Steuben County, with some also in Allegany, Chautauqua, Livingston and Chemung counties. According to the DEC, there were almost 284 Mcf of gas produced from the Marcellus Shale between 2000 and 2014. The DEC also reported that between 1967 and 1999, there may have been as much as 543 Mcf of gas produced from the Marcellus Shale.

At the conclusion of a seven-year study of the environmental impact of high-volume hydraulic fracturing (HVHF), the New York DEC published the Final Supplemental Generic Environmental Impact Statement (SGEIS) in April, 2015; it is available at http://www.dec.ny.gov/energy/75370.html#2015. On June 29, 2015, the State Environmental Quality Review (SEQR) Findings Statement for HVHF was issued by the DEC Commissioner (available at http://www.dec.ny.gov/docs/materials_minerals_pdf/findingstatehvhf62015.pdf), which officially prohibits HVHF in New York.

Ohio: Based on completion reports from the Ohio Department of Natural Resources (DNR), about 9.2 bcf of gas and over 295,000 bbls of oil were produced from the Marcellus Shale from 2007 through 2015 (most recent data available). There were 17 wells that reported production from the Marcellus Shale in 2015. According to the DNR completion reports, there were about 6.4 bcf of gas and about 198,400 bbls of oil produced in 2015. As of December, 2016, 44 Marcellus Shale horizontal well permits were issued, 29 horizontal wells had been drilled into the Marcellus Shale, and 21 horizontal wells were classified as producing from the Marcellus Shale, according to the Ohio DNR. The horizontal Marcellus Shale wells reported as productive were in Belmont, Carroll, Jefferson, and Monroe counties.

The maximum thickness of the Marcellus Shale in Ohio is about 75 feet, but generally the Marcellus Shale is 30-50 feet thick in the productive area in eastern Ohio (Erenpreiss and others, 2011). The depth to the base of the Marcellus Shale in the productive area in eastern Ohio is 3,000-5,000 feet. The Ohio Geological Survey published a map of the area of potential production from the Marcellus Shale (http://geosurvey.ohiodnr.gov/portals/geosurvey/Energy/Utica/Utica_Marcellus_Ohio_8x11.pdf), which included the counties of Ashtabula, Lake, Trumbull, Mahoning, Columbiana, Carroll, Jefferson, Harrison, Belmont, Guernsey, Monroe, Stark, Tuscarawas, and Washington. The DNR Division of Oil and Gas Resources Management published new draft rules pertaining to horizontal well site construction, which are available for review and comment at http://oilandgas.ohiodnr.gov/laws-regulations/opportunities-for-involvement#PPR.

Pennsylvania: The Marcellus Shale is deepest in north-central Pennsylvania, and the deepest wells to test the Marcellus Shale have been drilled to 8,500 feet in Clinton County (Harper and Kostelnik, undated). The organic-rich, high gamma ray portion of the Marcellus Shale is thickest in southwestern and north-central Pennsylvania (Perry and Wickstrom, 2010, and Harper, 2008), reaching about 400 feet thick in Susquehanna and Wyoming counties (Erenpreiss and others, 2011). Pennsylvania has continued to be the state with the most drilling into, and production from, the Marcellus Shale. In 2015, according to the Pennsylvania Department of Conservation

and Natural Resources (DCNR) and Department of Environmental Protection (DEP), the areas of greatest drilling activity in the Marcellus Shale continued to be in southwestern and northeastern Pennsylvania. The production of oil and condensate from fields in southwest Pennsylvania made this area attractive to operators. According to the Pennsylvania DCNR and DEP, the county with the most gas production in the first nine months of 2016 from the Marcellus Shale was Susquehanna County, where more than 817 bcf of gas was produced. After Susquehanna, the other counties with the most natural gas production in the first nine months of 2016 were Bradford, Washington, Lycoming, Greene, and Wyoming. The counties with the most condensate production in the first nine months of 2016 from the Marcellus Shale were Washington, Butler, and Beaver. The only counties with reported oil production in the first nine months of 2016 were Washington and Greene.

According to DCNR and DEP, by October, 2016, over 5,800 wells reported production from the Marcellus Shale, and about 98% of those productive wells were horizontal wells. According to DCNR and DEP, about 2.8 tcf of gas, almost 2 million bbls of condensate, and about 11,600 bbls of oil were produced from the Marcellus Shale in the first nine months of 2016. So far in 2016, Cabot Oil & Gas Corporation was the largest producer of natural gas from the Marcellus Shale, followed by Chesapeake Appalachia LLC, SWN (Southwestern Energy) Production Company, Range Resources Appalachia LLC, EQT Production Company, and Chief Oil & Gas LLC. Range Resources was the largest producer of condensate from the Marcellus Shale in 2016, followed by RE Gas Development LLC, SWN (Southwestern Energy) Production Company LLC, Pennenergy Resources LLC, and Noble Energy Inc. So far in 2016, Noble Energy was the only company to report oil production from the Marcellus Shale.

Beginning in January, 2015, the Pennsylvania DEP began reporting production from unconventional wells on a monthly basis. In 2015, there were 1,910 permits issued for unconventional wells, and 785 unconventional wells were drilled in Pennsylvania.

Tennessee: According to de Witt and others (1993), the Marcellus Shale is present in the subsurface in northeastern Tennessee. Therefore, in 2011, the USGS determined that the Foldbelt Marcellus Assessment Unit extended into Tennessee (Figure 1). According to the Tennessee Department of Environment and Conservation, Division of Water Resources, Oil and Gas Section, there is no production from the Marcellus Shale in Tennessee.

Virginia: According to the Virginia Division of Gas & Oil (DGO), there were no wells drilled exclusively for the Marcellus Shale in Virginia between 2004 and 2015. It is possible that natural gas was produced from the Marcellus Shale commingled with other zones in vertical wells in Virginia, but the quantity is unknown. A significant fraction of potentially productive acreage in Virginia is on national forest land. The U.S. National Forest Service (NFS) updated the George Washington National Forest (GWNF) Plan in November, 2014. The NFS chose Alternative I regarding lands administratively available for oil and gas leasing. The approximately 10,000 acres of mineral rights under current federal oil and gas leases will continue to be legally available for federal oil and gas leasing. None of these are currently active, but those lands will remain available for leasing after the current leases expire, terminate or are relinquished. All other areas of the GWNF are now administratively unavailable for federal oil and gas leasing, which includes about 1,056,000 acres. The Final GWNF Plan documents, including the revised forest plan, maps, and the final environmental impact statement, can be accessed at the following link: http://www.fs.usda.gov/detail/gwj/landmanagement/?cid=fsbdev3_000397.

West Virginia: West Virginia is second to Pennsylvania in cumulative production of natural gas from the Marcellus Shale. According to the West Virginia Geological and Economic Survey (WVGES), the first production reported from a horizontal well completed in the Marcellus Shale in West Virginia was in 2007. From 2007 through 2015, about 2.9 tcf of gas were produced from horizontal wells completed in the Marcellus Shale, as well as about 17.3 million bbls of oil and

about 5.2 million bbls of NGL. According to the West Virginia Department of Environmental Protection (WVDEP) and WVGES (Dinterman, 2016), there was reported production from the Marcellus Shale in 1668 horizontal wells, and reported production from the Marcellus Shale in 1298 vertical wells in 2015. Production was co-mingled in vertical wells, thereby making it difficult to separate Marcellus Shale production figures for those wells. According to Dinterman (2016), there were over 10.2 million bbls of liquid hydrocarbons produced (oil and natural gas liquids) and about 1.13 tcf of gas produced from the Marcellus Shale in 2015. In 2015, the companies reporting the most gas production from the Marcellus Shale were Antero Resources Corporation, EQT Production Co., Southwestern Production Co., Noble Energy, Inc., Ascent Resources, and Stone Energy Corporation. The companies reporting the most liquids production from the Marcellus Shale in 2015 were Southwestern Production Co., Jay-Bee Oil & Gas, Noble Energy, Inc., Triad Hunter LLC, and Antero Resources Corp.

In 2015, the counties from which most of the liquids were produced were Tyler, Marshall, Ohio, Wetzel, Brooke, Doddridge, and Ritchie. The counties from which most of the natural gas was produced were Doddridge, Wetzel, Harrison, Marshall, Ritchie, Tyler, Ohio, Taylor, Marion and Barbour.

In the area where there is Marcellus Shale production in West Virginia, the thickness of the Marcellus Shale is 30 to 120 feet, according to WVGES. The depth to the base of the Marcellus Shale ranges from about 4,000 feet in Brooke and Jackson Counties to about 7,000 feet in Taylor and Preston Counties. According to Moore and others (2015), in northern West Virginia, the total organic carbon (TOC) content is generally 10% or greater, and reservoir pressures range from 0.3 to 0.7 psi/foot.

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

http://www.eia.gov/oil_gas/rpd/shale_gas.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/geology/minerals_energy_resources/marcellus.html

http://www.mgs.md.gov/geology/minerals_energy_resources/natural_gas.html

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

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

http://www.dec.ny.gov/energy/1603.html

http://www.nysm.nysed.gov/research-collections/geology

http://geosurvey.ohiodnr.gov/energy-resources/marcellus-utica-shales

http://oilandgas.ohiodnr.gov/production

http://oilandgas.ohiodnr.gov/

http://oilandgas.ohiodnr.gov/shale

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

https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/DataExports/DataExports.aspx

https://www.dmme.virginia.gov/DGO/HydraulicFracturing.shtml

http://www.fs.fed.us/r8/gwj/

http://pubs.er.usgs.gov/publication/ofr20151061

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The Graneros-Greenhorn Petroleum System, a possible new resource play, Rocky Mountain Region, USA

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Abstract

High total organic carbon content (TOC) in the Graneros and Greenhorn formations and limestone lithologies in the Greenhorn suggest potential for a new resource play in the Rocky

Mountain region. Operators are currently testing new horizontal wells in the play. The source rocks are dominantly Type II with a mixture of Type III.

The Greenhorn Formation is a pelagic carbonate and mudstone deposit and consists of three members: Bridge Creek, Hartland, and Lincoln. Pelagic constituents consist of nannofossils (coccoliths and calcispheres) and foraminifera (mainly planktonic). The formation ranges in thickness in the northern Denver Basin from 150 to 350 ft. The Bridge Creek and Lincoln are predominantly chalk units or chalky marl units (40-85 % $CaCO_3$). The Hartland is a chalky marl (20 – 80% $CaCO_3$). TOC in the Bridge Creek, Hartland, and Lincoln members ranges from 0.5 to 5 wt. %. The Hartland contains the high levels of organic carbon and has the lowest levels of fossil diversity and abundance suggesting low oxygen or anoxic conditions during deposition. Depositional depths for the chalk units is probably 100 to 500 ft.

The Graneros interval occurs below the Greenhorn and above the D Sandstone over much of the Denver basin. Where the D pinches out the Graneros terminology is extended down to the top of the Mowry Shale. The Graneros to Mowry interval ranges in thickness from 150 to 400 ft across the northern Denver basin. TOC in the Graneros ranges from 0.5 to 5.3 wt. %. The overall distribution of the TOC in the Graneros is more consistent (not as cyclic) than in the Greenhorn.

Production from vertical Greenhorn wells has been encountered in the general Denver Basin area. Production comes mainly from the Lincoln member. Widespread shows and vertical production suggest the potential for a horizontal drilling play in the Greenhorn Formation.

Introduction

The Graneros-Greenhorn Petroleum System (.) is a wide spread unit in the Denver Basin. Organic-rich source rocks are found in both the Graneros and Greenhorn formations (Kaiser, 2012; Durkee, 2016). Reservoir rocks are found in the Greenhorn Limestone. This petroleum system is age equivalent to the Eagle Ford Formation of the Gulf Coast region. Numerous hydrocarbon shows and some vertical well production suggest the high potential for this petroleum system in the Denver Basin (Kaiser, 2013; Durkee, 2016). Horizontal drilling and multistage hydraulic fracture stimulation may be keys to future production from this interval.

The Graneros and Greenhorn were deposited during the Cenomanian and lower Turonian stages of the Cretaceous (~ 92.1 to 97.2 Ma, Kauffman et al., 1993) (Figures 1, 2). Paleoenvironmental reconstruction for Greenhorn time is shown by Figure 2.

This paper illustrates the potential of the Greenhorn to become a resource play and some of the similarities between the Greenhorn and the existing resource play of the Niobrara Formation. The term resource play implies widespread production (continuous accumulation) with somewhat predictable, repeatable results.

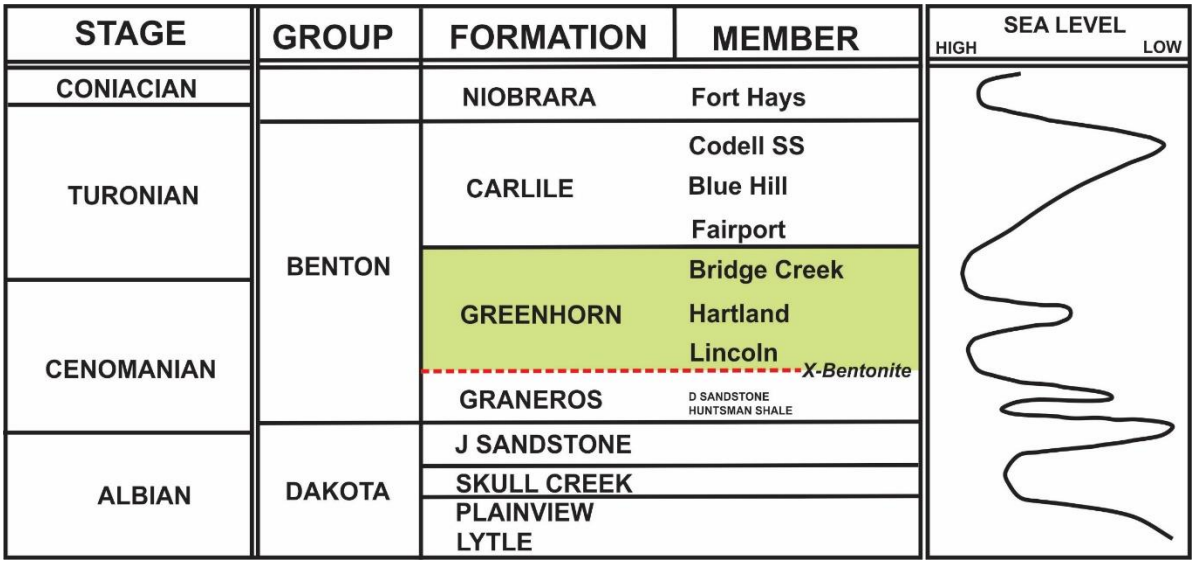

Figure 1. Stratigraphic column for the Cretaceous Dakota through lower Niobrara intervals. Sea level curve illustrates interpreted sea level changes for these time intervals.

Regional Geology

During mid- to late Cretaceous, the Western Interior seaway was present in western North America (Figure 2). The ancient seaway connected the proto Gulf of Mexico to the northern Boreal Sea (Arctic Ocean) (Kauffman, 1977). The western side of the seaway was the site of clastic deposition associated with the Sevier Orogenic Belt. The eastern side of the seaway was part of the low-lying Appalachia craton area and probably had little sedimentation into the seaway. This seaway resulted in several thousand feet of sedimentation in what is known as the Western Interior Cretaceous Basin (WIB). The basin ceased to exist with the onset of the Laramide Orogeny (latest Cretaceous to Eocene) that broke the WIB into current Rocky Mountain intermountain basins (e.g., Denver Basin).

Two cycles of carbonate deposition are found in Cretaceous strata in the seaway (Greenhorn and Niobrara, Figure 3) (Kauffman, 1969). The carbonates are deep-water carbonates that were associated with some of the highest sea levels in the Western Interior basin (Figure 1). The carbonates consist largely of chalks and marls. The Greenhorn consists of three members: Lincoln Limestone, Hartland Shale, and Bridge Creek Limestone. The Greenhorn overlies the Graneros and is beneath the Carlile. The Niobrara overlies the Carlile and consists of four to six chalk units (A, B1, B2, C, D, and Fort Hays) separated by marl beds.

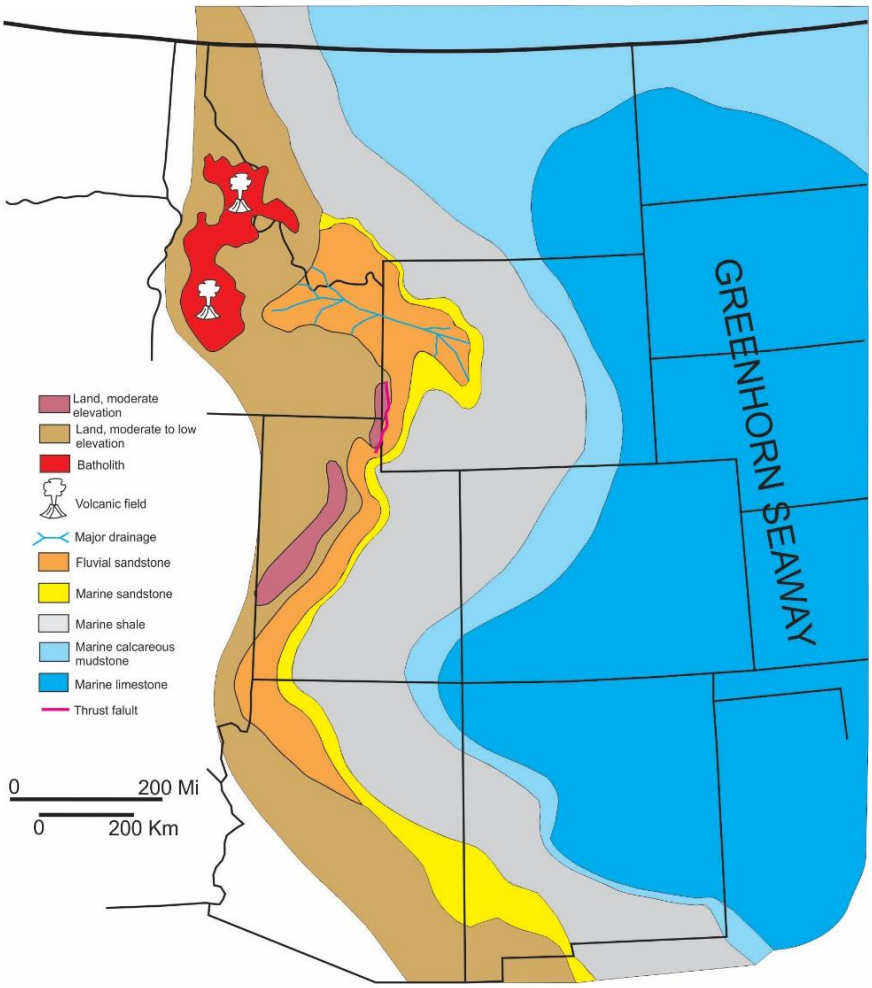

Figure 2. Paleoenvironment map for middle Greenhorn time from McGookey (1972). Seaway connected the arctic region to the Gulf of Mexico region.

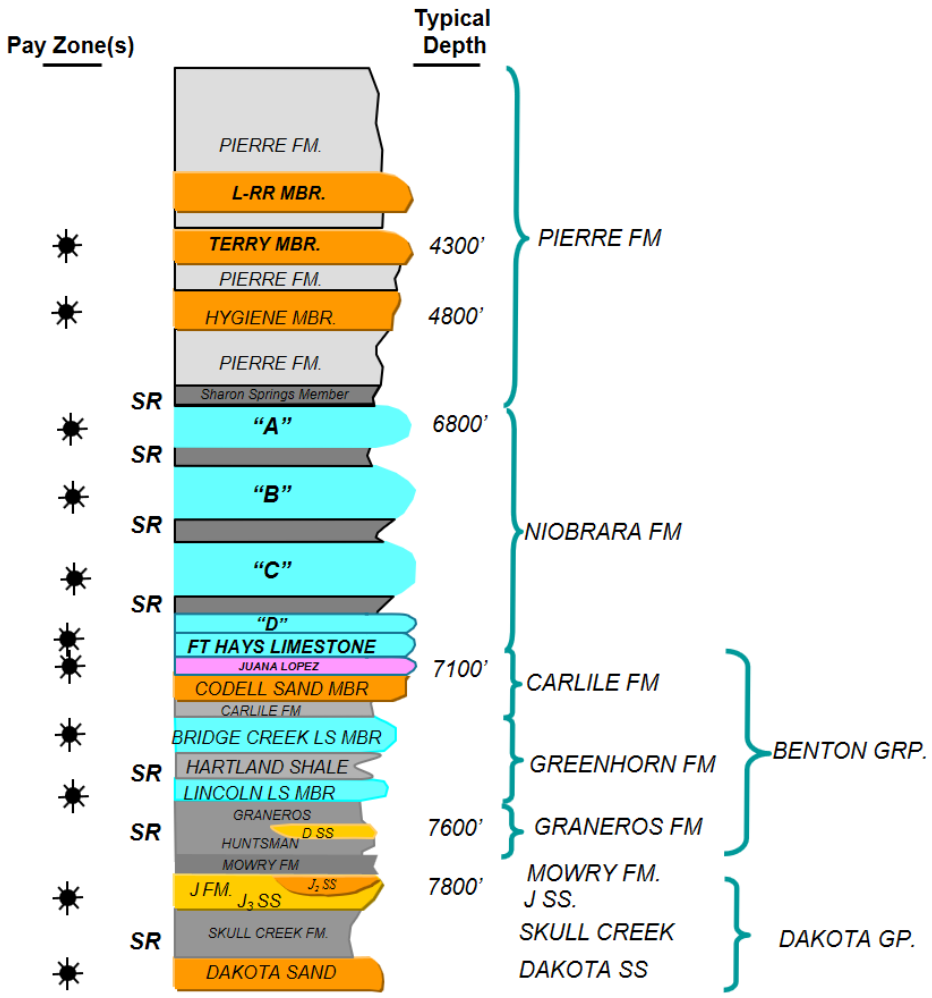

Figure 3. Stratigraphic column illustrating pay intervals and source beds and typical vertical drilling depths, Greater Wattenberg Field, Denver Basin.

Denver Basin

The Denver Basin is a large asymmetric basin located in northeast Colorado, northwest Nebraska, and southeast Wyoming (Figure 4). The deepest part of the basin occurs close to and parallels the Front Range and Laramie Range of Colorado and Wyoming, respectively. The deepest area of the basin is located close to Denver where the stratigraphic thickness is approximately 13,000 ft. The "cooking pot" or "kitchen" for the basin occurs along the basin axis.

The study area for this paper is the northern Denver Basin where the petroleum system has been extensively studied (Kaiser, 2012; Durkee, 2016). The Aristocrat H11-07 well from the Wattenberg Field is used to demonstrate petrophysics, geomechanics, and source-rock quality for the Graneros-Greenhorn interval. The Wattenberg Field is a basin-center type of field with multiple Cretaceous pay intervals (Figures 3, 4). Productive horizons for Wattenberg are shown on Figure 3. Wattenberg was discovered in 1970 and produces from the following Cretaceous horizons: J Sandstone, D Sandstone, Codell Sandstone, Niobrara Formation, Hygiene Sandstone, Terry Sandstone and Larimer Rocky Ridge Sandstone. Wattenberg Field is associated with a geothermal anomaly (Meyer and McGee, 1985; Higley and Cox, 2007). This anomaly appears to be associated with the Colorado Mineral Belt (a northeast zone of late Cretaceous and early

Tertiary mineralization that crosses the state of Colorado). A type geophysical log for the Wattenberg area is shown in Figure 5. The most important production volumetrically to date for the Wattenberg Field comes from the J Sandstone, Codell Sandstone, and Niobrara Formation. Most all the hydrocarbon pay zones in Wattenberg are regarded as unconventional (low porosity and permeability) and require fracture stimulation.

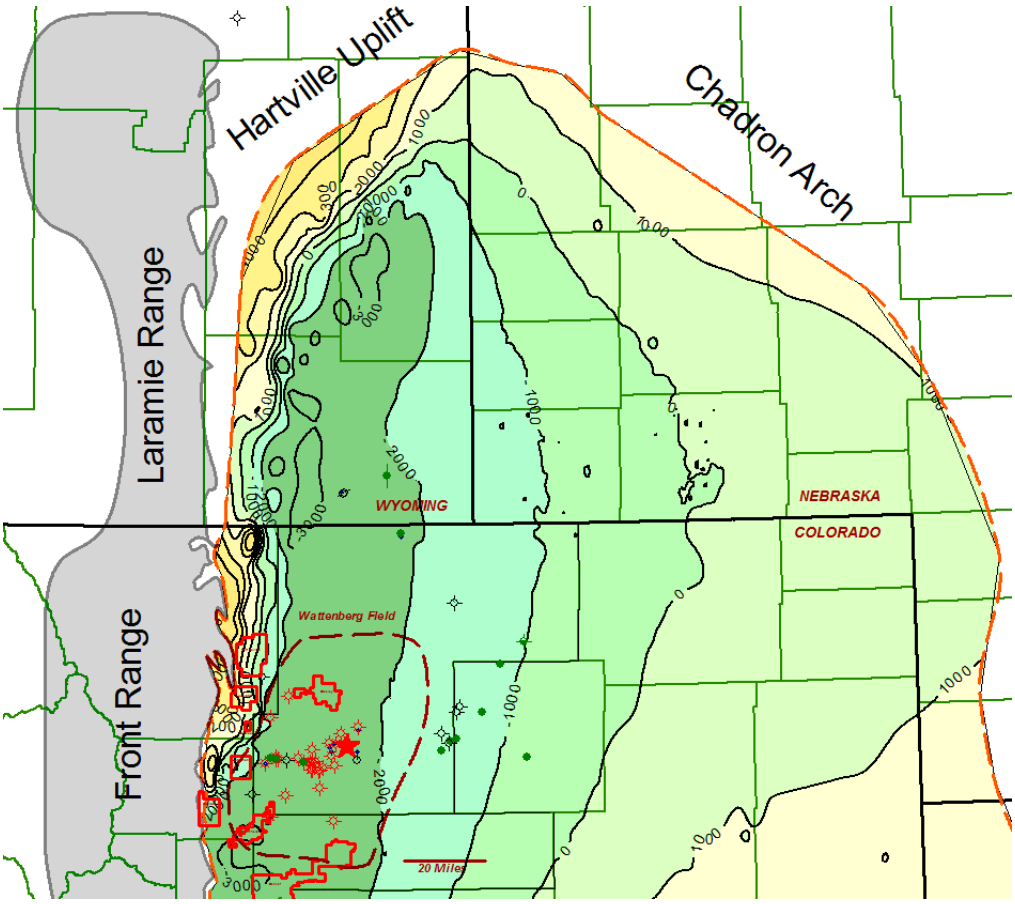

Figure 4. Structure contour map Codell Sandstone, northern Denver Basin. Wells shown were completed in the Greenhorn. Red dashed line is location of Wattenberg Field. Star indicates Aristocrat H11-07 well location. Greenhorn production is gas in the deeper parts of the Denver Basin and oil is shallower parts of the basin.

Graneros-Greenhorn Petroleum System

A petroleum system consists of source rocks and all the genetically related hydrocarbon accumulations (Magoon and Dow, 1994). The Graneros-Greenhorn potential petroleum system has organic-rich source beds in both the Graneros and Greenhorn (mainly the Hartland Shale but also organic-rich beds in the Lincoln and Bridge Creek members of the Greenhorn). Potential reservoir beds are the Lincoln and Bridge Creek limestone members of the Greenhorn. Wells completed in the Greenhorn (to date) in the Denver Basin are shown on Figure 4. In the Wattenberg area, Greenhorn production is mainly wet gas and condensate whereas wells to the east produce oil.

Stratigraphy

Graneros

The Graneros interval occurs between the Greenhorn and the D Sandstone over much of the Denver basin. Where the D pinches out the Graneros terminology is extended down to the top of the Mowry Shale (Figures 3, 5). The Graneros interval ranges in thickness from 150 to 350 ft across the northern Denver basin (Figure 6). Dramatic thickening of the interval occurs to the

northwest. This thickening is interpreted to be due to higher rates of siliciclastic deposition in this area. TOC in the Graneros ranges from 0.5 to 5.3 wt. %. The overall distribution of the TOC in the Graneros is more consistent (not as cyclic) than in the Greenhorn. Typical geophysical log responses for the Graneros are shown in Figure 5. The high Gamma Ray values in the Graneros are due to the presence of uranium and thorium. The high uranium is attribute to the high TOC content in the Graneros. The high thorium values are associated with clays and bentonites.

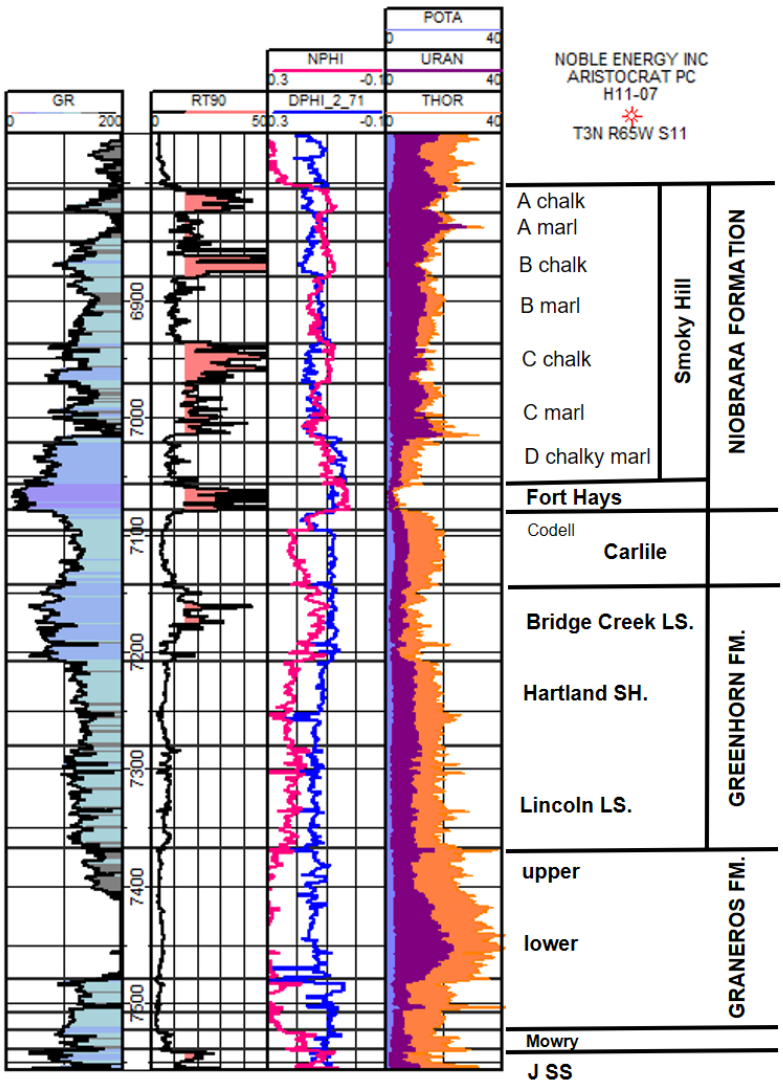

Figure 5. Well log for Niobrara through J Sandstone interval from Wattenberg Field. Location is shown by star on Figure 4. Logs shown are Gamma Ray (GR), Resistivity (RT90), Neutron porosity (NPHI), Density porosity (DPHI), and Spectra log Potassium (Pota), Uranium (Uran), and Thorium (Thor).

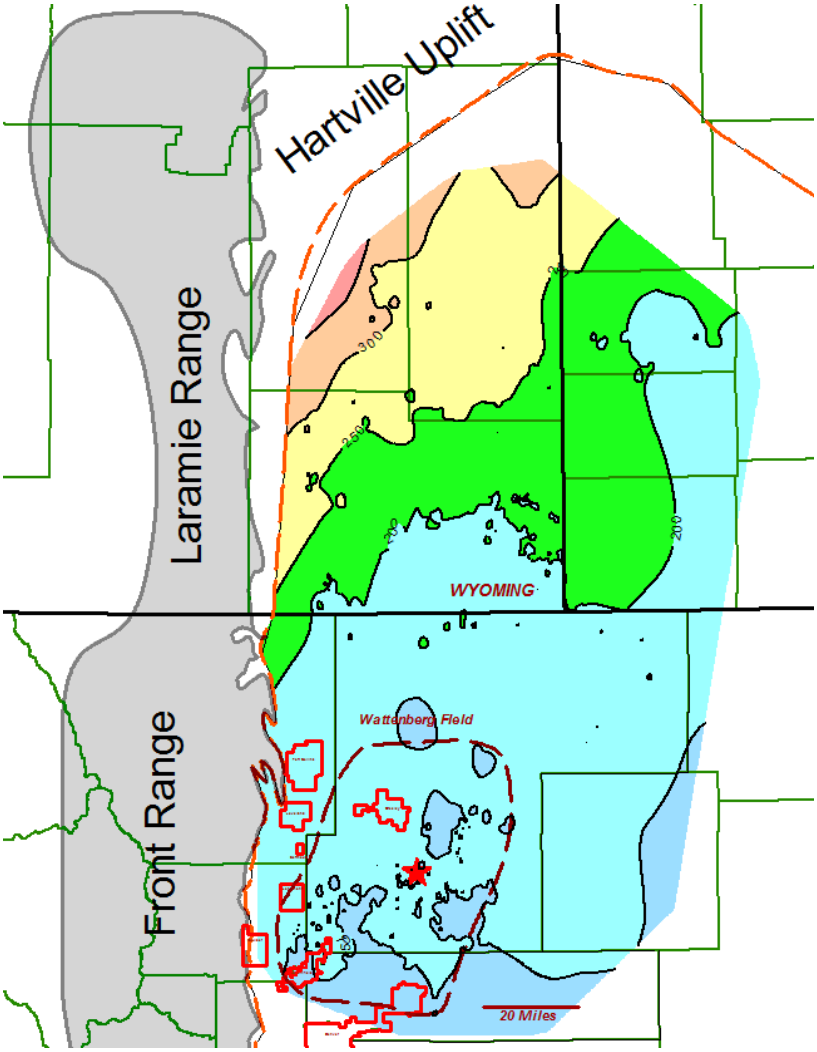

Figure 6. Isopach map of Graneros interval northern Denver Basin. Contour interval: 50 ft. Thickness ranges from 150 to 350 ft. Star indicates Aristocrat H11-07 well location. Red dashed line is location of Wattenberg Field.

Greenhorn

The Greenhorn is a pelagic carbonate and shale deposit and consists of three members (Hattin, 1979): Bridge Creek Limestone, Hartland Shale, and Lincoln Limestone (Figures 3, 5). The Bridge Creek and Lincoln are potential reservoir units and the Hartland is a potential source bed. Pelagic constituents consist mainly of nannofossils (coccoliths and calcispheres) and microfossils (mainly planktonic foraminifera). Macrofossils such as inoceramids and oysters also occur in the Greenhorn. The Greenhorn Formation represents a complex mixed siliciclastic-carbonate depositional setting with several facies that represent transitions from chalk to marl to mudstone. The formation ranges in thickness in the northern Denver Basin from 100 to 350 ft (Figure 7). Dramatic thickening occurs to the northwest. The thickening is again interpreted to be due to higher rates of siliciclastic deposition in this northern area.

The Bridge Creek and Lincoln are largely chalk units or chalky marl units (40-85 % $CaCO_3$). The Bridge Creek Member represents a biogenic pelagic-dominated system. The Lincoln represents a detrital carbonate dominated depositional system with significant calciclastic hypopycnal influence and tempestite deposition (foraminiferal packstones and grainstones). The Hartland is a chalky marl (20 – 80% $CaCO_3$) and regarded as a source rock, with total organic carbon (TOC) values of 2-4%, predominantly Type II marine kerogen. The Hartland has the lowest levels of fossil diversity and abundance suggesting low oxygen or anoxic conditions during deposition (Sageman, 1985). Depositional water depths for the chalk units is probably 100 to 500 ft (Hattin, 1979).

The Greenhorn is thermally mature in the Wattenberg Field and in deeper areas along the basin axis in the Northern Denver Basin. The Greenhorn is similar in lithology and porosity to the overlying Niobrara Formation. The Bridge Creek Member represents a biogenic pelagic-dominated system, whereas the Hartland and the Lincoln represent a detrital dominated depositional system with significant clastic hypopycnal influence and tempestite deposition (Durkee, 2016).

Log porosities for the Greenhorn are 8-12%. Core porosity and permeability for the Bridge Creek are 1.21-5.25% and .0022 md, respectively. Core porosity and permeability for the Hartland Shale is 1.25-1.34% and 0.0015 md respectively. Core porosity and permeability for the Lincoln are 2.79-5.07% and .004 md, respectively.

Figure 8 illustrates a three well cross section with core descriptions for the Greenhorn interval from the Pueblo area to the Silo Field area. The cross section illustrates the dramatic northward thickening of the Greenhorn in the northern Denver Basin.

The dramatic thickening of the Greenhorn to the north in the Denver Basin is due mainly to thickening within the Bridge Creek member. Most of this thickening is interpreted to be due to clastic dilution of carbonate units coming from the northwest.

A generalized stratigraphic column showing various facies present for the Greenhorn is shown by Figure 9. The Lincoln member is finely laminated, and consists of calcareous shales and marls with interbedded carbonate-rich chalk beds. The Hartland is relatively homogenous and consists of foraminifera-rich, laminated calcareous mudstone. The Bridge Creek consists of fine-grained chalks with laminar organic-rich calcareous shale and marl.

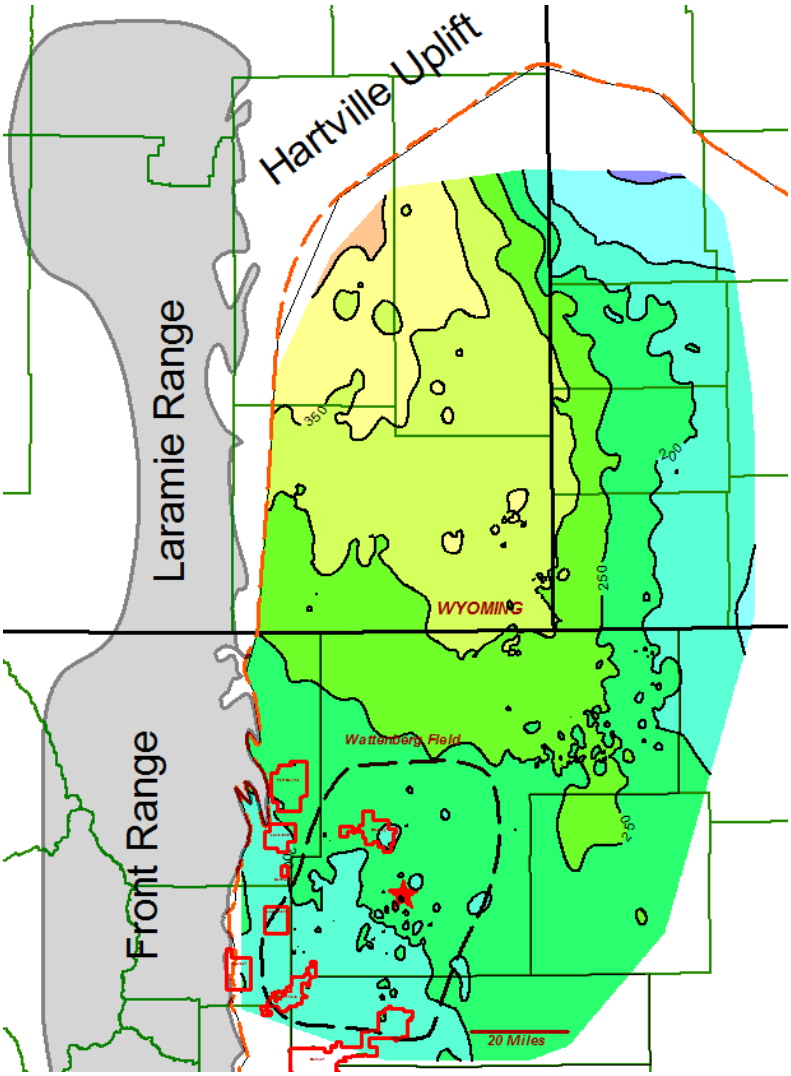

Figure 7. Isopach map of Greenhorn interval northern Denver Basin. Contour interval: 50 ft. Thickness ranges from 150 to 400 ft. Star indicates Aristocrat H11-07 well location. Red dashed line is location of Wattenberg Field.

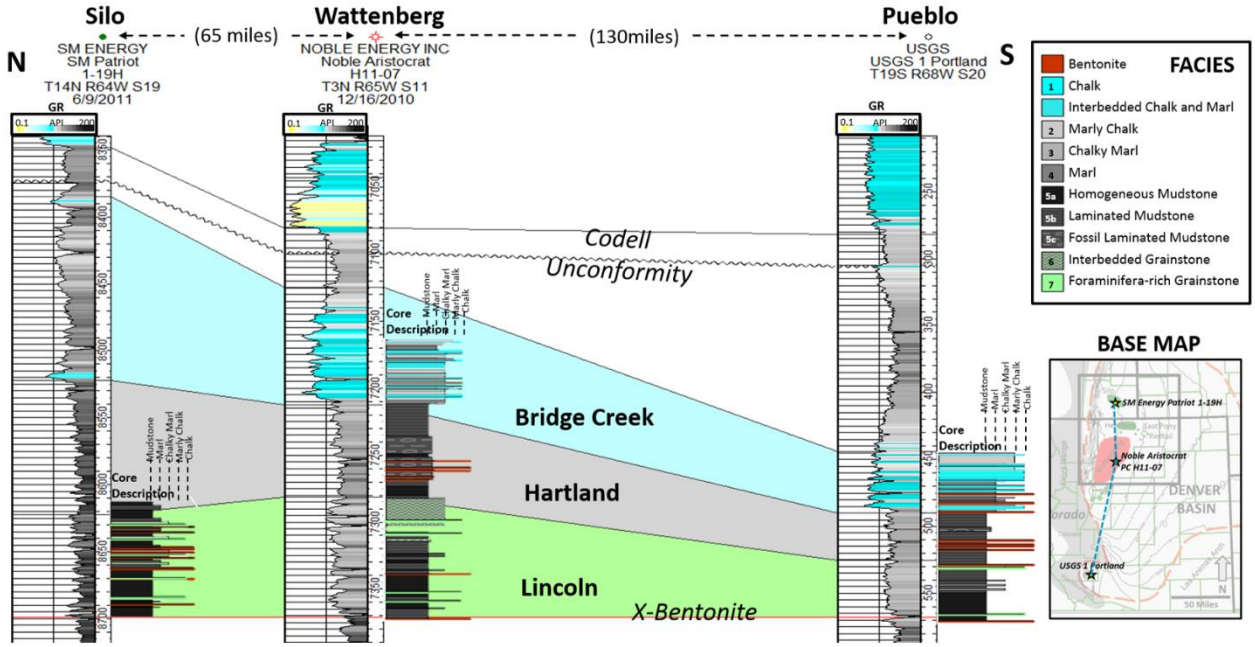

Figure 8. Three well cross section with core descriptions Greenhorn Formation, northern Denver Basin (from Durkee, 2016).

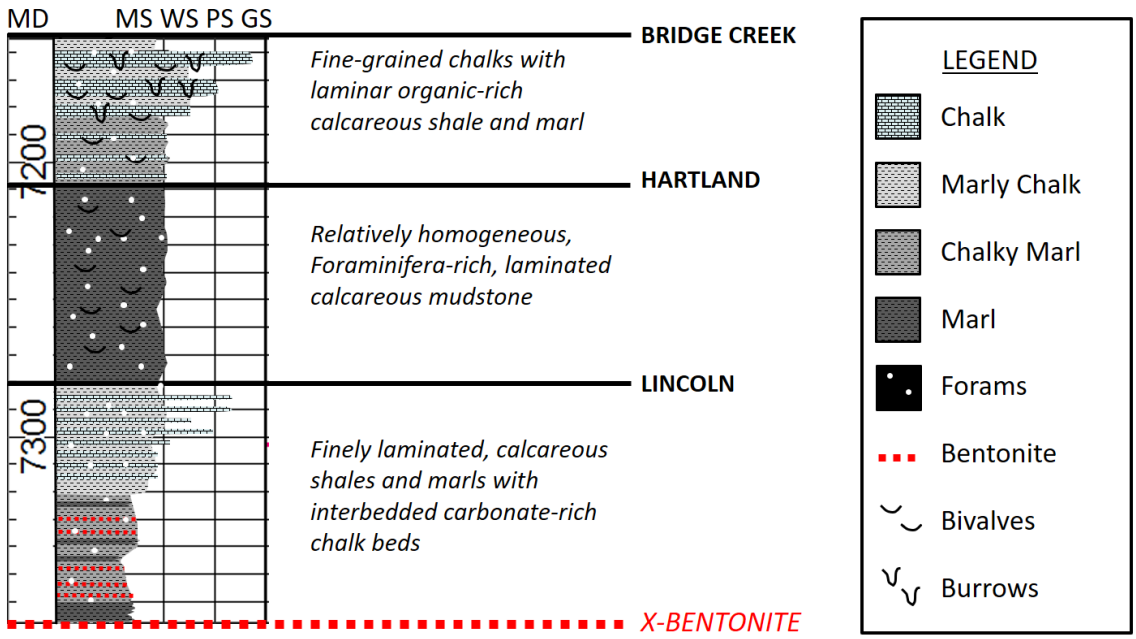

Figure 9. Generalized stratigraphic column for Greenhorn Formation, Aristocrat H11-07 (sec. 11, T3N, R65W) Wattenberg area (from Durkee, 2016).

Petrophysics

Typical geophysical log responses for the Niobrara and Greenhorn formations from Wattenberg Field are shown in Figure 5. Distinct gamma ray, resistivity, porosity, bulk density, sonic, and spectral gamma ray signatures characterize each unit. The GR curve distinguishes chalk (low GR) from marl units (high GR). If thick enough, the chalks also have higher resistivities than the

marls (clays associated with the marls lowers resistivity). The thin-bed effect mutes the resistivity in the Lincoln member. Neutron and density logs approach each other in the carbonate-rich intervals. The curves diverge in the shalier intervals. Spectral gamma logs show components of potassium, uranium, and thorium within the formation. Potassium is used to indicate clay concentrations; thorium is associated with heavy clay minerals and bentonites; uranium can be used as a proxy for organic matter. The Bridge Creek shows relatively low concentrations of uranium, potassium, and thorium, suggesting the interval is low in organic matter and clay. The Hartland and Lincoln members show higher values of these elements suggesting higher clay and organic matter. Overall, the Bridge Creek is similar in appearance to Niobrara chalks. The Hartland and Lincoln are similar to Niobrara marls.

XRD Mineralogy

The Greenhorn Formation is composed of siliciclastic (quartz silt and clay) and carbonates (mostly calcite with minor dolomite) (Figure 10). Mineralogy and clay characterization are important components for Greenhorn reservoir characterization. On a ternary plot of clay versus quartz versus carbonate, the Greenhorn plots in the mixed mudstone to mixed carbonate mudstone areas (plot after Gamero-Diaz et al., 2012). Pure chalk beds from the Bridge Creek plot in the carbonate quadrant. The Hartland and Lincoln are similar and plot in the mixed mudstone area, whereas, the Bridge Creek with its higher carbonate content plots in the mixed carbonate mudstone area. Overall, siliciclastic abundance increases from the Bridge Creek to the Lincoln. Carbonate abundance decreases between the Bridge Creek and other Greenhorn members.

Average mineralogy for the Bridge Creek is 24.5% clay, 54% carbonate, and 20% quartz. Average mineralogy for the Harland is 36.75% clay, 37.5% carbonate, and 20% quartz. Average mineralogy for the Lincoln is 36.33% clay, 31.33% carbonate, and 23.75% quartz (Durkee, 2016).

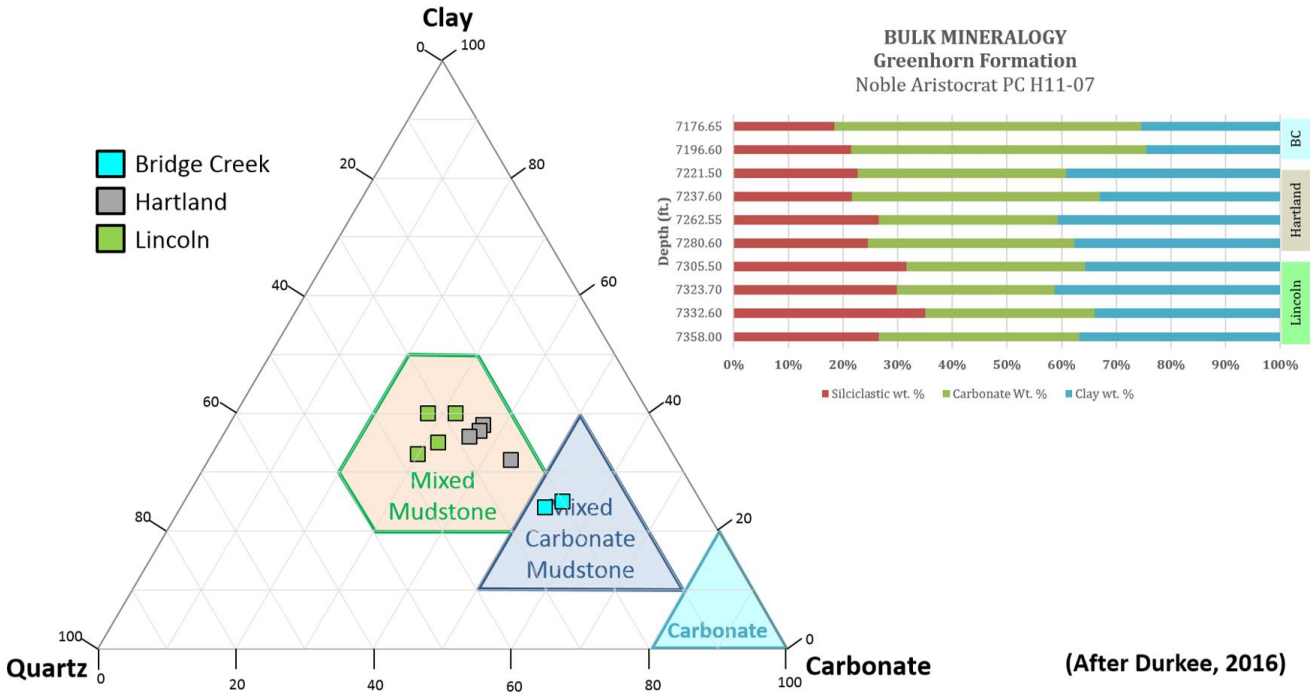

Figure 10. Bulk mineralogy from X-Ray diffraction illustrates highest carbonate content in Bridge Creek samples; the Hartland and Lincoln have 30 to 40% clay content.

XRF Chemo-Stratigraphy

Mudrock units can be characterized by using XRF elemental data. Organic richness, paleo-productivity, and detrital indicators can be determined. Geochemical data used for the Durkee (2016) study was provided by Nakamura (2015). Elemental data can be combined into the following five categories:

- Detrital indicators: aluminum (Al), titanium (Ti), potassium (K), and silicon (Si). These elements are associated with terrigenous minerals including clay minerals, feldspars, and quartz.
- Carbonate indicators: calcium (Ca) and strontium (Sr). These elements are associated with carbonate.
- Organic productivity indicators: chromium (Cr), zinc (Zn), vanadium (V), molybdenum (Mo), uranium (U), and nickel (Ni). These elements are associated with organic matter, redox conditions and are indicative of suboxic environments.
- Anoxic indicators: The elements in this category have some overlap with the organic suite. This group also includes vanadium (V), molybdenum (Mo), uranium (U) and nickel (Ni), as well as iron (Fe) and sulfur (S). The latter two elements are associated with pyrite. These elements are associated to anoxic conditions associated with redox reactions.
- Oxic indicators: Consists of manganese (Mn) which is associated with oxic to suboxic conditions.

Elevated values of detrital elements indicate increases in terrigenous minerals and clays within marl facies within each Greenhorn member (Figure 11). The highest concentration of detrital elements is found in the Hartland Shale. Elevated carbonate indicators are associated with chalky facies of the Bridge Creek and decrease in both the Hartland and Lincoln members.

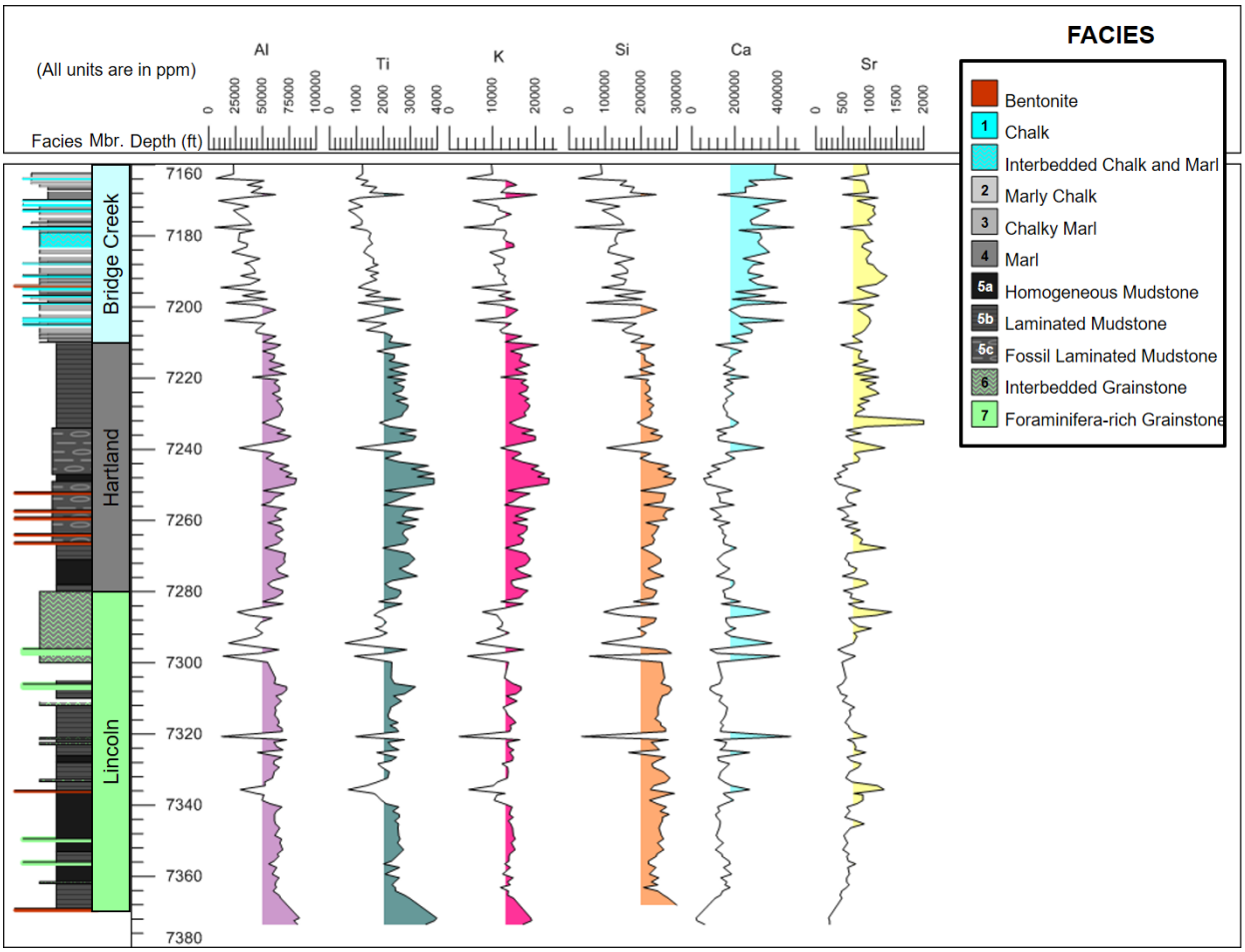

Figure 11. Elemental data for detrital (Al, Ti, K, and Si) and carbonate (Ca and Sr) indicators plotted against Aristocrat H11-07 core description and depth; elemental concentrations are in parts per million (ppm). From Durkee, 2016.

Elemental data associated with organic productivity and anoxic indicators show elevated values in the Hartland and Lincoln members indicating that these units were deposited under reducing, dysoxic to anoxic water conditions (Figure 12). Anoxic conditions are highly favorable for preservation of organic material. Organic and anoxic elements exist in low quantities in the carbonate-rich facies of the Bridge Creek. The oxic indicator, manganese (Mn), shows elevated values in the Bridge Creek suggesting deposition under oxic to suboxic conditions. Chalk beds in the Bridge Creek are also bioturbated.

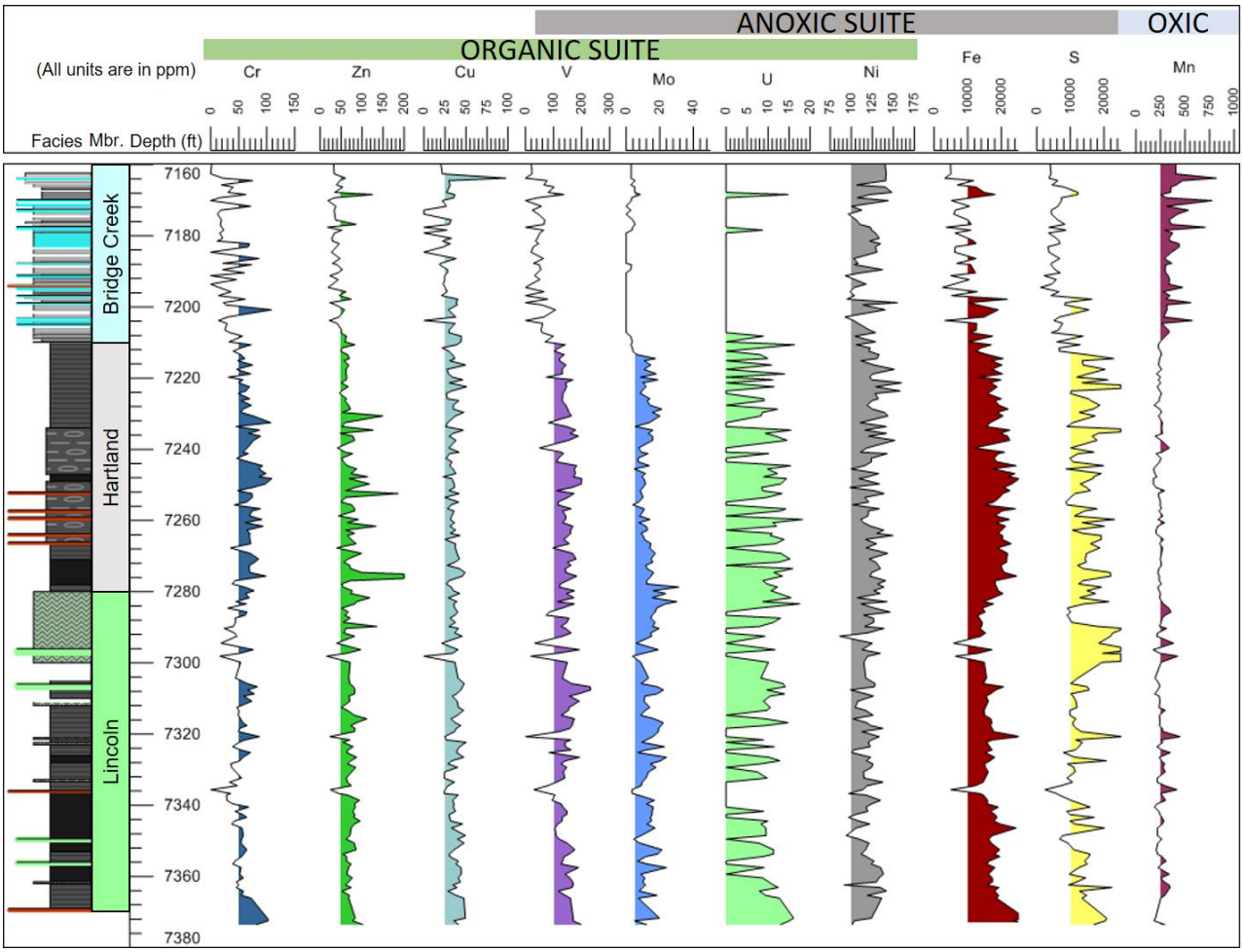

Figure 12. Elemental data for the organic (Cr, Zn, Cu, V, Mo, U, and Ni), anoxic (V, Mo, U, Ni, Fe, and S), and oxic (Mn) suites plotted against the Noble Aristocrat PC H11-07 core description and depth. Elemental concentrations are in parts per million (ppm). From Durkee, 2016.

Source Beds

Source beds for the Graneros-Greenhorn Petroleum System are the Graneros shale, and all members of the Greenhorn (Figure 13). The Bridge Creek and Lincoln members of the Greenhorn consist of couplets of organic-rich mudstone and carbonate beds. TOC values as measured are a function of the original organic content but affected thermal maturity of the samples. In areas of high thermal maturity, a greater proportion of the TOC has converted to hydrocarbons. The following general numbers were measured from samples in the greater Denver Basin area. The

Graneros has TOC contents of 2.8-5.2 wt. %. The Lincoln has values ranging from 2.2 to 4.7 wt. %. The Hartland has values ranging from 0.7-4.5 wt. %. The Bridge Creek has values ranging from 0.5-3.4 wt. %. Figure 13 illustrates source rock data from the Aristocrat H11-07 well located in the wet-gas window of the Wattenberg Field. The Graneros section was not analyzed in this well. The highest TOC values are found in the Hartland Shale and the Lincoln members of the Greenhorn. TOC in the Bridge Creek ranges from 0.5-3.4 wt. %. TOC in the Hartland ranges from 0.7-4.1 wt. %. TOC in the Lincoln ranges from 2.2-4.7 wt. %. Tmax values for the Bridge Creek, Hartland, and Lincoln members are 475, 485, and 485°C, respectively (Durkee, 2016). This indicates the source beds are thermally mature in the wet-gas window. Hydrogen index (HI) numbers less than 50 also indicate high thermal maturity for the Greenhorn in the Wattenberg area.

Figure 14 illustrates data from the Aristocrat Angus 12-8 well (sec. 8, T3N, R65W) from the Wattenberg Field (Kaiser, 2013). TOC contents for the Graneros and Greenhorn are good to excellent in spite of the fact of the high thermal maturity of the samples. The low S2 values on the plot in Figure 14 indicate that elevated thermal maturity.

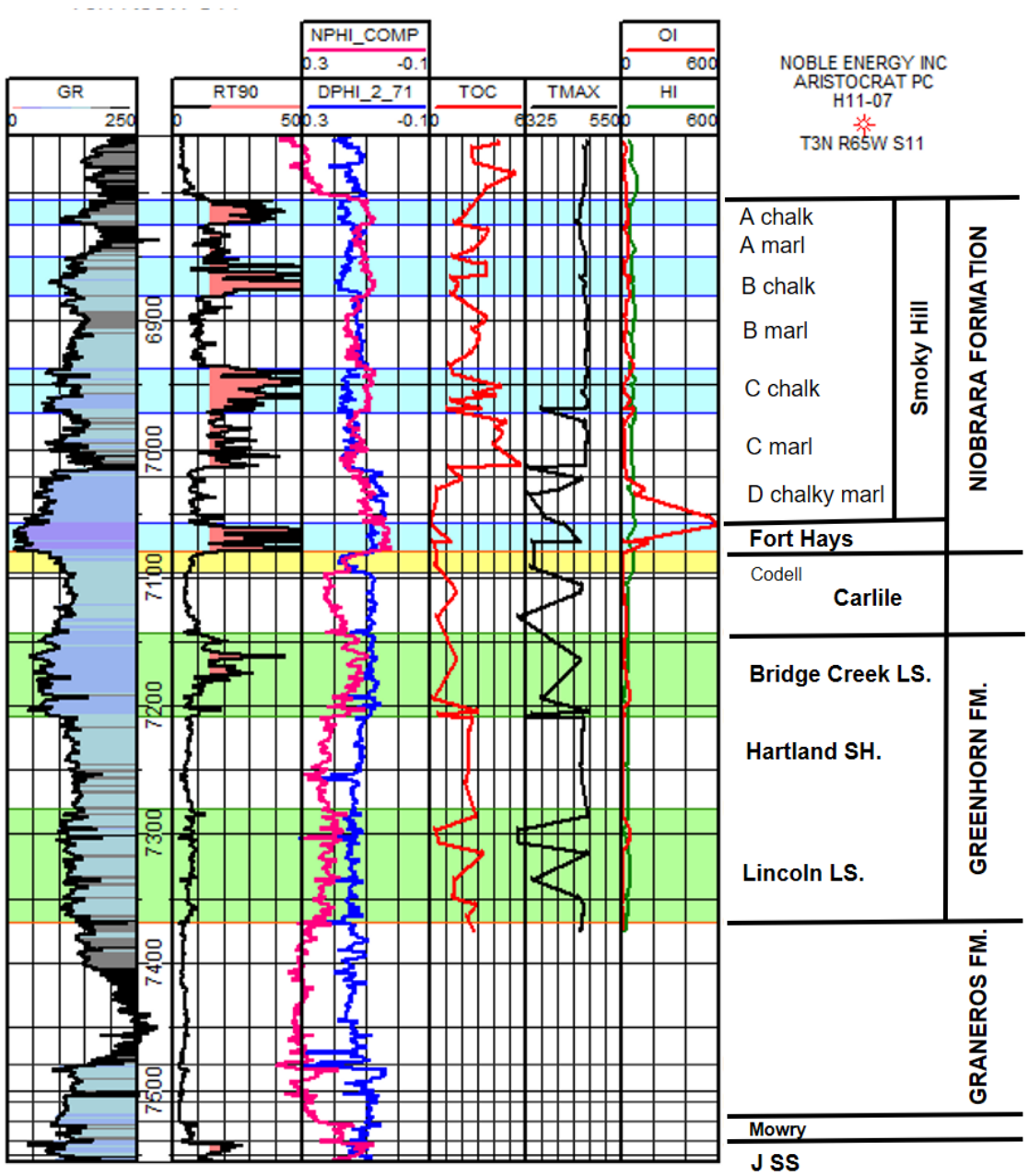

Figure 13. Well log and source rock analysis data for Niobrara through J Sandstone interval from Wattenberg Field. Location of well is shown by star on Figure 4. Logs shown are Gamma Ray (GR), Resistivity (RT90), Neutron porosity (NPHI), Density porosity (DPHI), total organic carbon (TOC), temperature maximum data (Tmax), oxygen index (OI), and hydrogen index (HI).

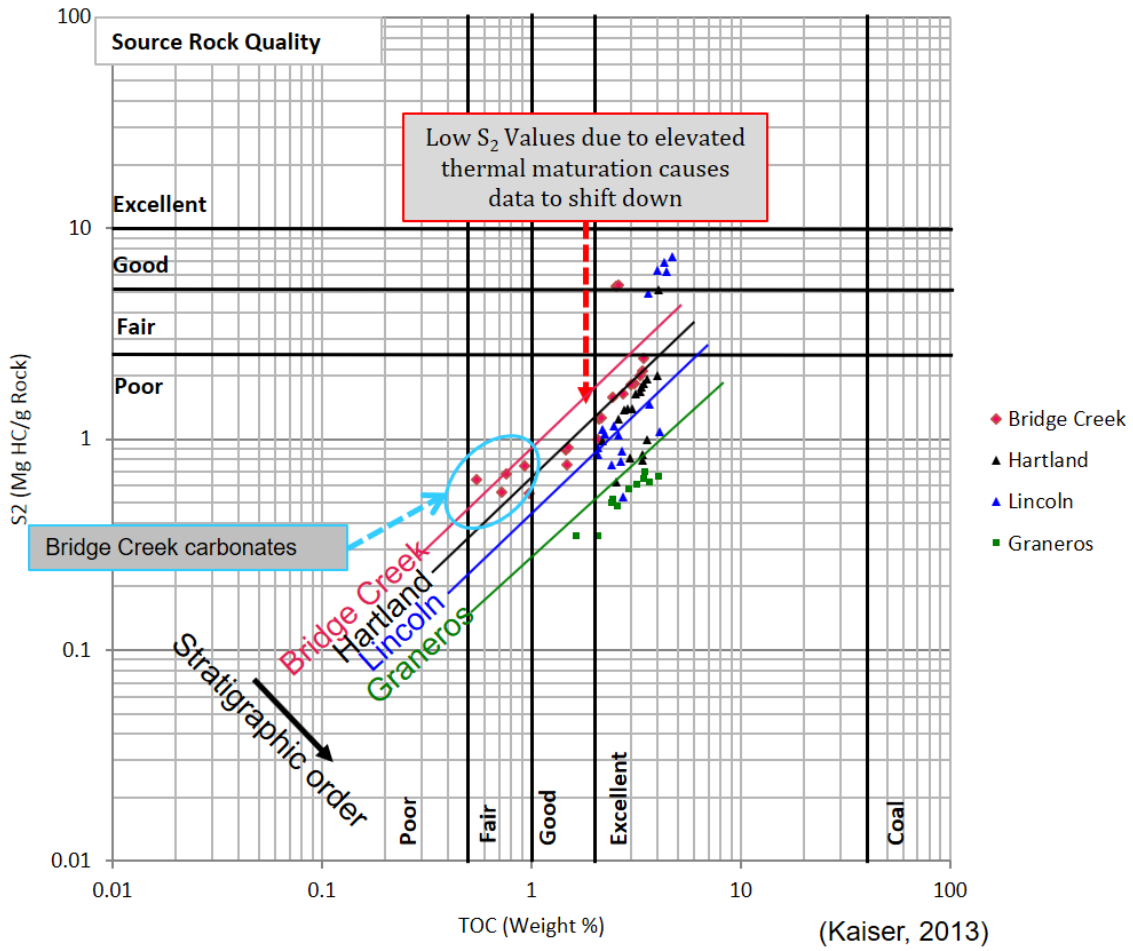

Figure 14. Source rock quality plot (S2 versus TOC) illustrating that source rocks in Bridge Creek, Hartland, Lincoln, and Graneros are good to excellent. Both S2 and TOC are lowered by thermal maturity so the overall initial source rock quality was even better. The poor S2 data values are due to thermal maturity. The data is from a well in the gas generation window. Data is from the Aristocrat Angus core studied by Kaiser, 2013.

Mechanical Stratigraphy

The mechanical stratigraphy of the Niobrara through Graneros intervals is shown by Figure 15. Young's modulus and Poisson's ratio were calculated from an available dipole sonic log. Brittleness as used in this paper is simply Young's modulus divided by Poisson's ratio. The highest values of Young's modulus are found in the chalk beds of the Niobrara and the Bridge Creek member of the Greenhorn. Alternating thin beds of carbonate and mudrock in the Lincoln member of the Greenhorn are thought to suppress the Young' modulus values. The Lincoln member overall resembles marl units of the Niobrara Formation. Both the marls and chalks of the Niobrara are thought to contribute to Niobrara production.

Both the Lincoln and Bridge Creek members appear to be more brittle than the Hartland Shale and Graneros Formation. Thus, both the Lincoln and Bridge Creek are recommended as

horizontal drilling targets. The Lincoln and Bridge Creek members should have a favorable response to hydraulic fracture stimulation similar to chalk beds in the Niobrara Formation (proven producers).

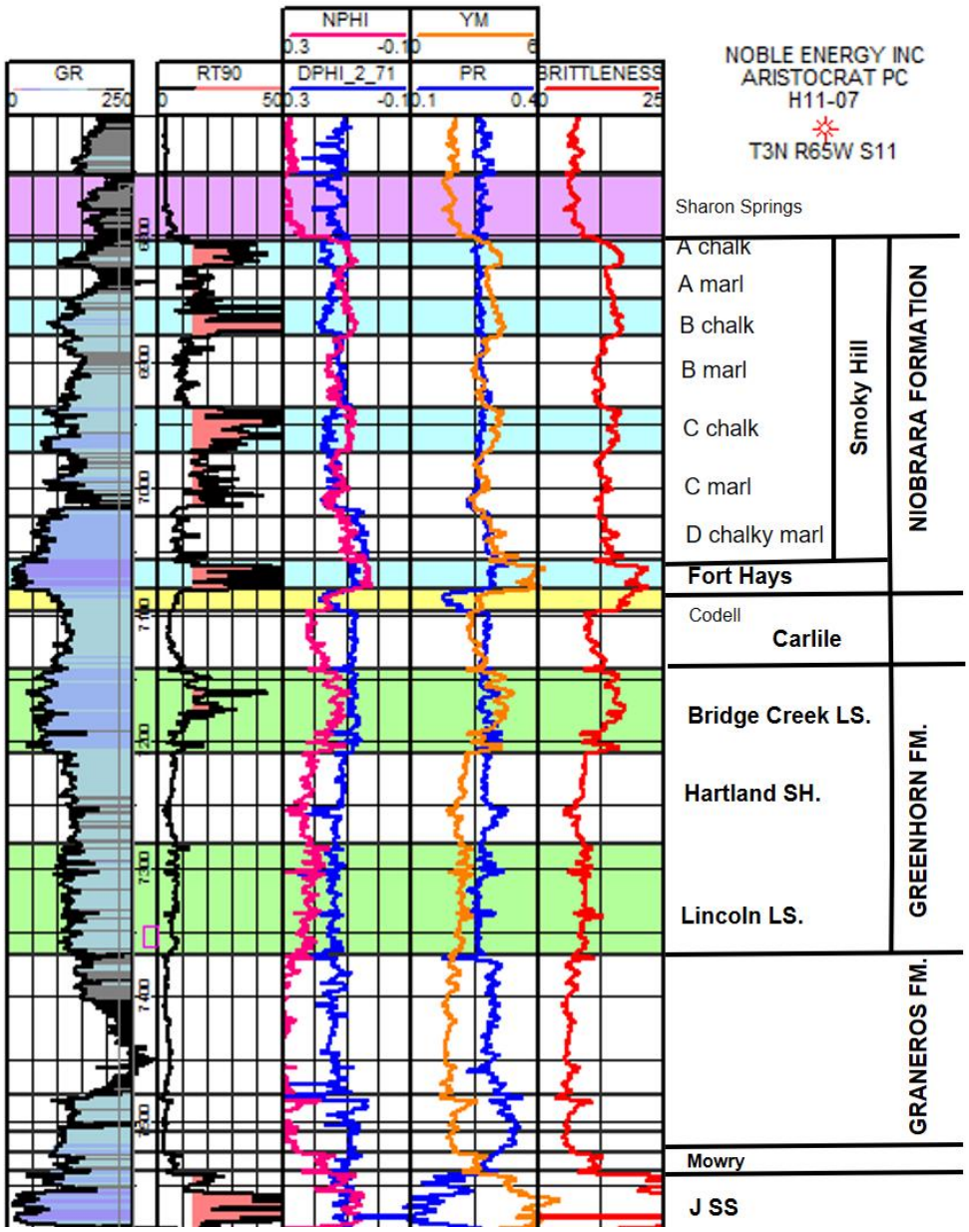

Figure 15. Well log for Niobrara through J Sandstone interval from Wattenberg Field. Location is shown by star on Figure 4. Logs shown are Gamma Ray (GR), Resistivity (RT90), Neutron porosity (NPHI), Density porosity (DPHI), Young modulus (YM), Poisson's ratio (PR), and Brittleness. The Bridge Creek is comparable geomechanically to various Niobrara chalk intervals. The Hartland and Lincoln members of the Greenhorn resemble marl intervals of the Niobrara Formation. Suggested target horizons for Greenhorn laterals are the Bridge Creek and Lincoln limestone members.

Horizontal Drilling

New horizontal wells with multistage hydraulic fracture stimulation are beginning to test the potential Greenhorn play in the Denver Basin. Operators (Noble, Anadarko, Chesapeake, and EOG) have all drilled horizontal Greenhorn wells. Results from these wells are not currently available. However, the high number of vertical Greenhorn completions in the Wattenberg Field suggest that this area is a logical location for future drilling activity (Figure 4).

Summary

The Graneros and Greenhorn formations both contain significant source rocks (TOC contents > 2.5 wt. %). The Bridge Creek member of the Greenhorn Formation appears to be similar in petrophysical and mechanical properties to chalk beds in the Niobrara Formation (a proven, active resource play). The Lincoln member of the Greenhorn is similar to marl beds of the Niobrara Formation (also known to produce).

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PERMIAN BASIN SHALES

Beau Tinnin and Bo Henks, Pioneer Natural Resources

The Permian Basin of southeast New Mexico and west Texas (Figure 1) is currently one of the most prolific oil producing regions in the United States. It has produced more than 29 billion barrels of oil and 75 trillion cubic feet of gas (Texas RRC) since the early 1920s. Numerous experts agree that the Permian Basin contains significantly more recoverable resource in place than what has previously been produced to date. Overall, the Permian Basin spans an area of approximately 250 miles wide by 300 miles long. The basin can be divided into several distinct structural and tectonic regions with current drilling activity focused in two sub-basins, the Midland Basin and the Delaware Basin, which are both separated by the Central Basin Platform (Figure 1). In a cross sectional view, the Permian Basin is highly asymmetric, with the western Delaware Basin comprised of thicker and more structurally deformed sediments than the eastern Midland Basin.

The Permian Basin is comprised of numerous vertically-stacked conventional reservoirs and organic-rich source rocks intervals with a vast majority of production coming from Permian- and Pennsylvanian-aged units. Traditionally, these formations have been developed with vertical wells and small hydraulic stimulations but more recently there has been a dramatic shift to horizontal drilling (Figure 2) and large multi-stage hydraulic stimulations. As of December 16, 2016, there were 258 rigs running in the Permian Basin with 216 horizontal/deviated wells and 42 vertical wells (data from Baker Hughes). Currently, rig counts are on a sharp rise after bottoming out earlier this year (Figure 3). But even with the falling rig count of 2015-2016 in the Permian Basin (Figure 3), the basin's production has continued to climb (Figures 4 and 5). Based on the U.S. EIA December 2016 Drilling Productivity Report, oil production has been steadily rising since 2010 when it was at approximately 900,000 barrels of oil per day and is now currently at approximately 2.1 million barrels of oil per day (Figure 6), despite the significant drop in rig count in late 2014/early 2015.

The substantial rise in oil production in the Permian Basin is directly tied to the uptick in horizontal well activity targeting tight oil formations. Oil and gas companies are actively drilling horizontal wells targeting the Clear Fork, Spraberry, and Wolfcamp formations in the Midland Basin and targeting the Brushy Canyon, Bone Spring, Wolfcamp, Cisco, and Canyon formations in the Delaware Basin.

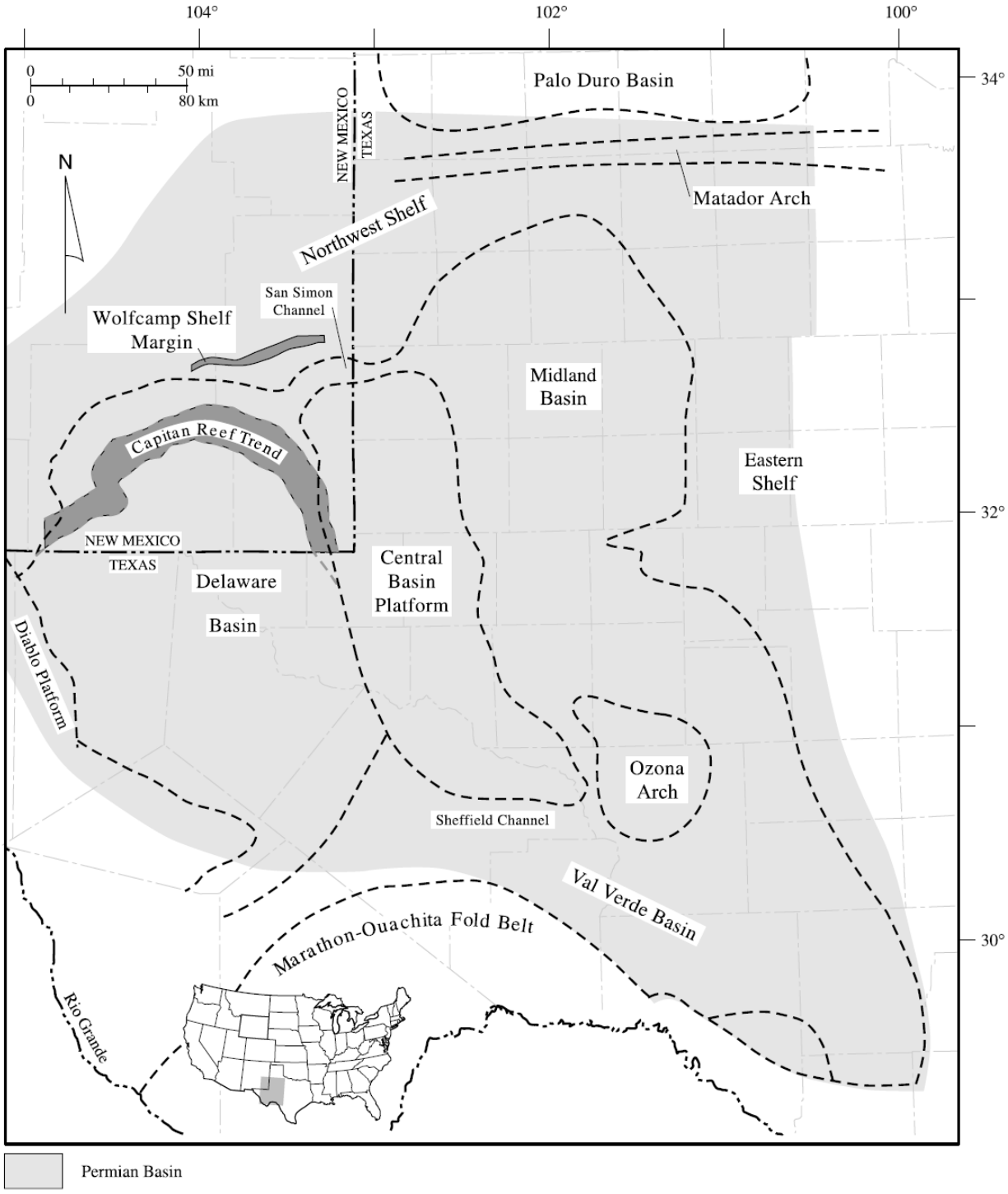

Figure 1: Map of the Permian Basin in southeast New Mexico and west Texas showing the major geologic and tectonic boundaries of the region. Figure from Dutton et al. (2005).

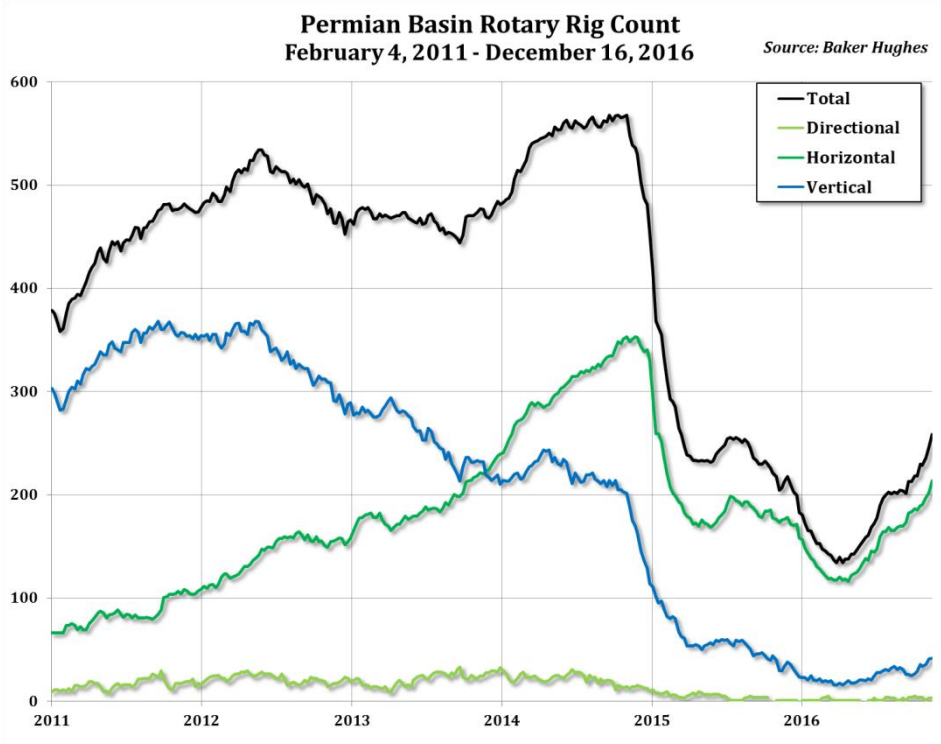

Figure 2: Permian Basin rotary rig count from February 2011 to December 2016 comparing vertical and deviated/horizontal wells in the basin. Rig count data from Baker Hughes.

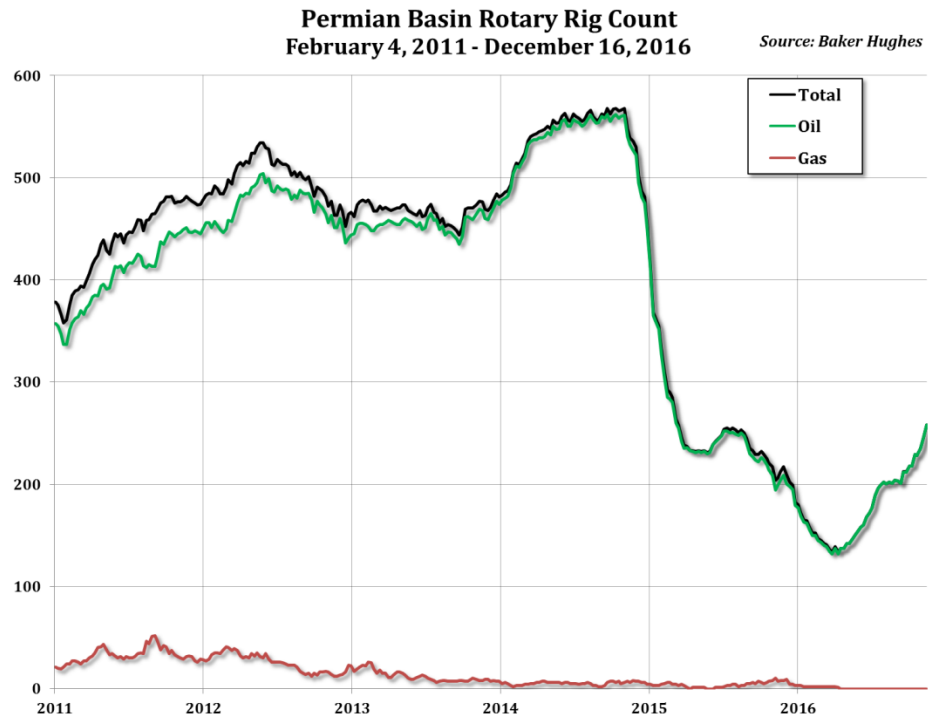

Figure 3: Permian Basin rig count from February 2011 to December 2016 comparing oil and gas rigs in the basin. Rig count data from Baker Hughes.

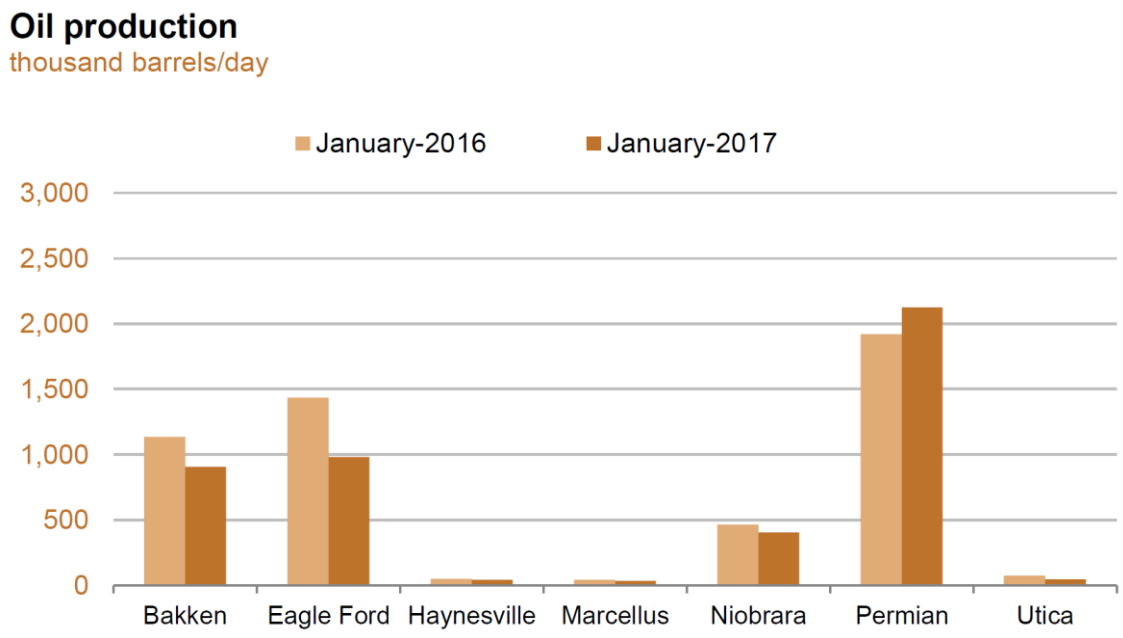

Figure 4: Oil production comparison of the Permian Basin (Texas and New Mexico) with six other significant tight oil and shale gas regions of the continental United States. Note: oil production is projected through January 2017 and represents both crude and condensate production from all formations within the region. Figure from U.S. EIA December 2017 Drilling Productivity Report. https://www.eia.gov/petroleum/drilling/pdf/dpr-full.pdf

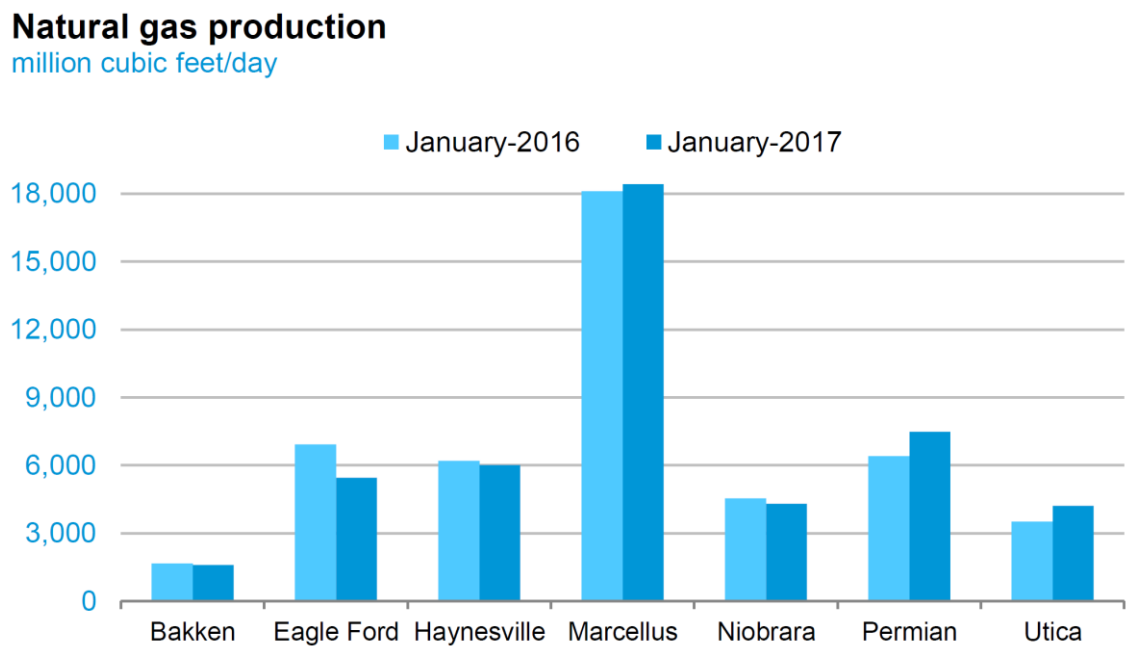

Figure 5: Natural gas production of the Permian Basin (Texas and New Mexico) with six other significant tight oil and shale gas regions of the continental United States. Note: gas production is projected through January 2017. Figure from U.S. EIA December 2016 Drilling Productivity Report. https://www.eia.gov/petroleum/drilling/pdf/dpr-full.pdf

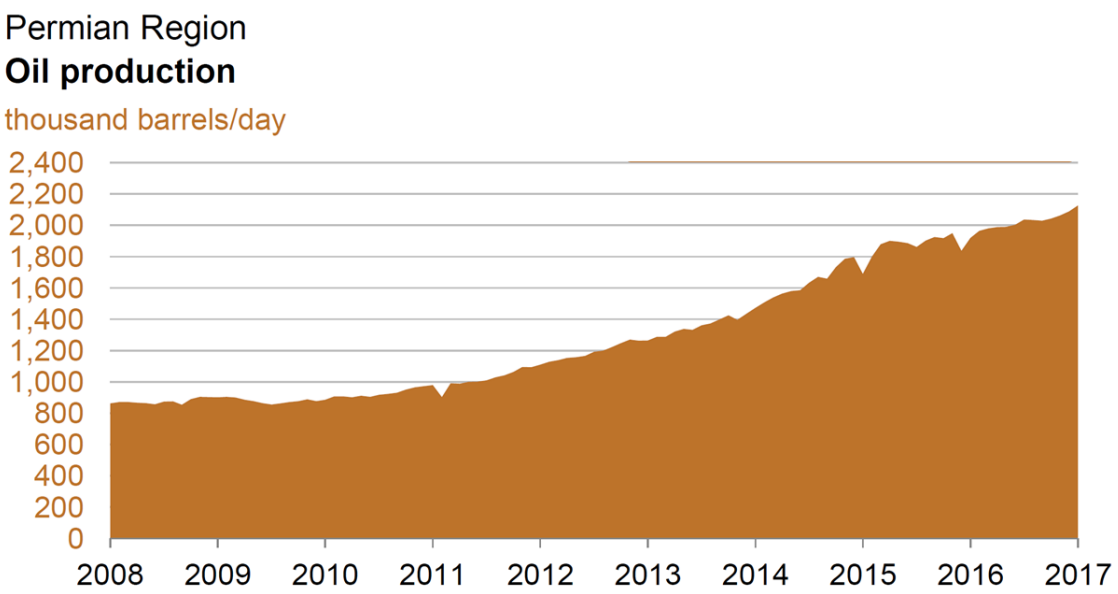

Figure 6: Oil production of the Permian Basin (Texas and New Mexico). Note: oil production is projected through January 2017 and represents both crude and condensate production from all formations within the region. Figure from U.S. EIA December 2016 Drilling Productivity Report. https://www.eia.gov/petroleum/drilling/pdf/dpr-full.pdf

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Tight-Oil Plays and Activities in Utah

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The dramatic crash of crude oil that occurred towards the end of 2014 continuing through 2016, coupled with ongoing low natural gas prices, has severely affected exploration and development of shale gas and liquids in Utah. Following on the success of the past shale gas boom elsewhere and employing many of the same well completion techniques, numerous petroleum companies had been exploring for liquid petroleum in shale formations in the state. In fact, many shales or low-permeable ("tight") carbonates targeted for natural gas include areas in which the zones are more prone to liquid production. Organic-rich shales in the Uinta and Paradox Basins have been the source for significant hydrocarbon generation, with companies traditionally targeting the interbedded sands or porous carbonate buildups for their conventional resource recovery. With the advances in horizontal drilling and hydraulic fracturing techniques, operators in these basins

explored the petroleum production potential of the shale and interbedded tight sand and carbonate units themselves.

Uinta Basin

Overview

The Uinta Basin is the most prolific petroleum province in Utah. It is a major depositional and structural basin that subsided during the early Cenozoic along the southern flank of the Uinta Mountains. Lake deposits filled the basin between the eroding Sevier highlands to the west and the rising Laramide-age Uinta Mountains, Uncompahgre uplift, and San Rafael Swell to the north, east, and south, respectively. The southern Eocene lake, Lake Uinta, formed within Utah's Uinta Basin and Colorado's Piceance Creek Basin.

The Green River Formation consists of as much as 6000 ft of sedimentary strata (Hintze and Kowallis, 2009; Sprinkel, 2009) and contains three major depositional facies associated with Lake Uinta sedimentation: alluvial, marginal lacustrine, and open lacustrine (Fouch, 1975). The marginal lacustrine facies, where most of the hydrocarbon production is found, consists of fluvial-deltaic, interdeltaic, and carbonate flat deposits, including microbial carbonates. The open-lacustrine facies is represented by nearshore and deeper water offshore muds, including the famous Mahogany oil shale zone, which represents Lake Uinta's highest water level.

The Uinta Basin is asymmetrical, paralleling the east-west trending Uinta Mountains. The north flank dips 10-35º southward into the basin and is bounded by a large north-dipping, basement-involved thrust fault. The southern flank gently dips between 4-6º north-northwest.

Activity

Tight-oil drilling and exploration activities in the Uinta Basin target relatively thin porous carbonate beds of the Uteland Butte Limestone Member of the lower Green River Formation (figure 1), particularly in an area referred to as the "Central Basin region" between Altamont-Bluebell field to the north and Monument Butte field to the south. The Uteland Butte has historically been a secondary oil objective of wells tapping shallower overlying Green River reservoirs and deeper fluvial-lacustrine Colton Formation sandstone units in the western Uinta Basin.

The Uteland Butte records the first major transgression of Eocene Lake Uinta after the deposition of the alluvial Colton Formation, and thus it is relatively widespread in the basin (figure 2). The Uteland Butte ranges in thickness from less than 60 ft to more than 200 ft and consists of limestone, dolomite, organic-rich calcareous mudstone, siltstone, and rare sandstone (figures 1, 3, and 4). The dolomite (figure 1), the horizontal drilling target, often has more than 20% porosity, but is so finely crystalline that the permeability is very low (single mD or less).

Several companies (Newfield, LINN, Bill Barrett Corporation, Crescent Point, QEP Resources, Petroglyph, and Axia) have targeted the Uteland Butte with horizontal wells in both the central, normally pressured part of the basin near Greater Monument Butte field, and farther north in the overpressured zone in western Altamont field. Since spring 2016, there have been four rigs drilling wells in the Uinta Basin some of which have targeted the Uteland Butte. However, drilling records are kept confidential for up to a year by the Utah Division of Oil, Gas, and Mining.

Paradox Basin

Overview

The Paradox Basin is located mainly in southeastern Utah and southwestern Colorado with small portions in northeastern Arizona and the northwestern corner of New Mexico. The Paradox Basin is an elongate, northwest-southeast-trending, evaporitic basin that predominately developed during the Pennsylvanian, about 330 to 310 Ma. The basin was bounded on the northeast by the Uncompahgre Highlands as part of the Ancestral Rockies. As the highlands rose, an accompanying depression, or foreland basin, formed to the southwest—the Paradox Basin. Rapid basin subsidence, particularly during the Pennsylvanian and continuing into the Permian, accommodated large volumes of evaporitic and marine sediments that intertongue with non-marine arkosic material shed from the highland area to the northeast. Deposition in the basin produced a thick cyclical sequence of carbonates, evaporites, and organic-rich shale of the 500- to 5000-ft-thick Pennsylvanian Paradox Formation (Hintze and Kowallis, 2009).

Rasmussen (2010) divided the middle part of the Paradox Formation in the evaporite basin into as many as 35 salt cycles, some of which onlap onto the basin shelf to the west and southwest (figure 5). Each cycle consists of a clastic interval/salt couplet. The clastic intervals are typically interbedded dolomite, dolomitic siltstone, anhydrite, and black, organic-rich shale—the sources of the petroleum in the basin. The clastic intervals typically range in thickness from 10 to 200 ft and are generally overlain by 200 to 400 ft of halite.

The Paradox Basin can generally be divided into three areas: the Paradox fold and fault belt in the north, the Blanding sub-basin in the south-southwest, and the Aneth platform in the southernmost part in Utah. The area now occupied by the Paradox fold and fault belt was the site of greatest Pennsylvanian/Permian subsidence and salt deposition. Folding in the Paradox fold and fault belt began as early as the Late Pennsylvanian as sediments were laid down thinly over, and thickly in areas between, rising salt. Spectacular salt-cored anticlines extend for miles in the northwesterly trending fold and fault belt. Reef-like buildups or mounds of carbonates consisting of algal bafflestone and oolitic/skeletal grainstone fabrics in the Desert Creek and Ismay zones of the Paradox Formation are the main hydrocarbon producers in the Blanding sub-basin and Aneth platform. Oil in these zones is sourced above, below, or within the organic-rich Gothic, Chimney Rock, Hovenweep, and Cane Creek shales (figure 5).

Activity

The Cane Creek shale zone of the Paradox Formation has been a target for tight-oil exploration on and off since the 1960s and produces oil from several small fields (figure 6). The play generated much interest in the early 1990s with the successful use of horizontal drilling. Currently, eight active fields produce from the Cane Creek in the Paradox Basin fold-and-fault belt, with cumulative oil production over 8 million bbls and 8 BCFG (Utah Division of Oil, Gas, and Mining, 2016). Until the recent drop in oil prices, the Cane Creek and other Paradox zones have been targeted for exploration using horizontal drilling.

The Cane Creek shale zone records an early stage of a transgressive-regressive sequence (cycle 21) in the Paradox Formation and consists of organic-rich marine shale with interbedded dolomitic siltstone and anhydrite (figure 7). The unit is up to 160 ft thick and areally extensive within the Paradox Basin. It is divided into the A, B, and C zones, with the shale and silty carbonates of the B zone considered both the source rock and reservoir. The A and C zones are anhydrite rich and provide an upper and lower seal to the B zone. The unit is highly overpressured, with measurements ranging between 5000 and 6200 psi, which is probably the result of hydrocarbon generation between very impermeable upper and lower anhydrite seals. The B zone is naturally fractured, and oriented cores show that fractures trend northeast-southwest, matching the regional structural trend.

The U.S. Geological Survey (2012), Whidden and others (2014), and Anna and others (2014) re-assessed the undiscovered oil resource in the Cane Creek shale at 103 million barrels at a 95% confidence level and 198 million barrels at a 50% confidence level. In addition to the Cane Creek, several other organic-rich shale zones are present in the Paradox Formation, creating the potential for significant resource base additions. The Gothic, Chimney Rock, and Hovenweep shales (figure 5) in the Blanding sub-basin and Aneth platform are estimated to hold an undiscovered oil reserve of 126 million barrels at a 95% confidence level and 238 million barrels at a 50% confidence level (U.S. Geological Survey, 2012; Whidden and others, 2014; and Anna and others, 2014).

Fidelity Exploration & Production Company, the major operator in the Cane Creek play for several years, estimated that with extended horizontal drilling the estimated ultimate recovery could be as much as 1.7 million bbls of oil per well (IHS Inc., 2014). However, no Cane Creek drilling activity was reported in 2016 due to continued depressed oil prices and lower than expected flow rates in recent wells. Fidelity completed the 24-mile, 12-inch diameter Dead Horse Lateral gas pipeline gathering system and Blue Hill gas plant so gas produced from the Cane Creek is now being sold instead of being flared as it was for many years. Finally, Fidelity recently sold their holdings to Wesco Operating Incorporation.

Current Research

The Utah Geological Survey (UGS), with funding from the National Energy Technology Laboratory, U.S. Department of Energy (DOE), is in the final year of a four-year project titled "Liquid-Rich Shale Potential of Utah's Uinta and Paradox Basins: Reservoir Characterization and Development." The overall goals of this study are to provide reservoir-specific geological and engineering analyses of the (1) emerging Green River Formation tight-oil plays (such as the

Uteland Butte Limestone Member, Black Shale facies, deep Mahogany zone, and other deep Parachute Creek member high-organic units) in the Uinta Basin, and (2) the established, yet understudied Cane Creek shale (and possibly other shale units such as the Gothic and Chimney Rock shale zones) of the Paradox Formation in the Paradox Basin. To accomplish these goals, the project will:

- Characterize geologic, geochemical, and petrophysical rock properties of target zones in the two designated basin areas by compiling various sources of data and by analyzing newly acquired and donated core, well logs, and well cuttings.
- Describe outcrop reservoir analogs of Green River Formation plays and compare them to subsurface data (not applicable in the Paradox Basin since the Cane Creek shale is not exposed).
- Map major regional trends for targeted liquid-rich intervals and identify "sweet spots" that have the greatest oil production potential.
- Suggest techniques to reduce exploration costs and drilling risks, especially in environmentally sensitive areas.
- Improve drilling and fracturing effectiveness by determining optimal well completion design.
- Suggest techniques to reduce field development costs, maximize oil recovery, and increase reserves.

The project will therefore develop and make available geologic and engineering analyses, techniques, and methods for exploration and production from the Green River Formation tight-oil zones and the Paradox Formation shale zones where operations encounter technical, economic, and environmental challenges.

In addition to a thorough geologic characterization of the target zones, tests will be performed to characterize the geomechanical properties of the zones of interest to inform/guide well completion strategies. The brittle characteristics of the target intervals will be studied in detail using energy-based calculations. This approach acknowledges both mechanical properties and in-situ stress conditions, as well as geometric lithologic constraints and the mineralogy that regulates fracturing. The study will establish a template for more effective well planning and completion designs by integrating the geologic characterization and formation evaluation with state-of-the-art rock mechanical analyses. This will help companies access oil they know is present, but technically difficult to recover.

To aid in the identification of hydrocarbon "sweet spots," novel concepts for exploration was employed, such as the use of low-cost, low-environmental impact, epifluorescence analysis of regional core and well cuttings. Epifluorescence microscopy is a technique used to provide information on diagenesis, pore types, and organic matter (including "live" hydrocarbons) within sedimentary rocks. It is a rapid, non-destructive procedure that uses a petrographic microscope equipped with reflected-light capabilities, a mercury-vapor light, and appropriate filtering. Epifluorescent intensities obtained from core and cuttings were mapped to help identify areas with potential for significant hydrocarbon production. The detailed reservoir characterization and rock mechanics analyses provide the basis for identification of "sweet spots" and improve well completion strategies for these undeveloped and under-developed reservoirs.

For more information about this ongoing project, including available posters and talks (in pdf), refer to the Utah Geological Survey's project website:
http://geology.utah.gov/resources/energy/oil-gas/shale-oil.

Recent Publications

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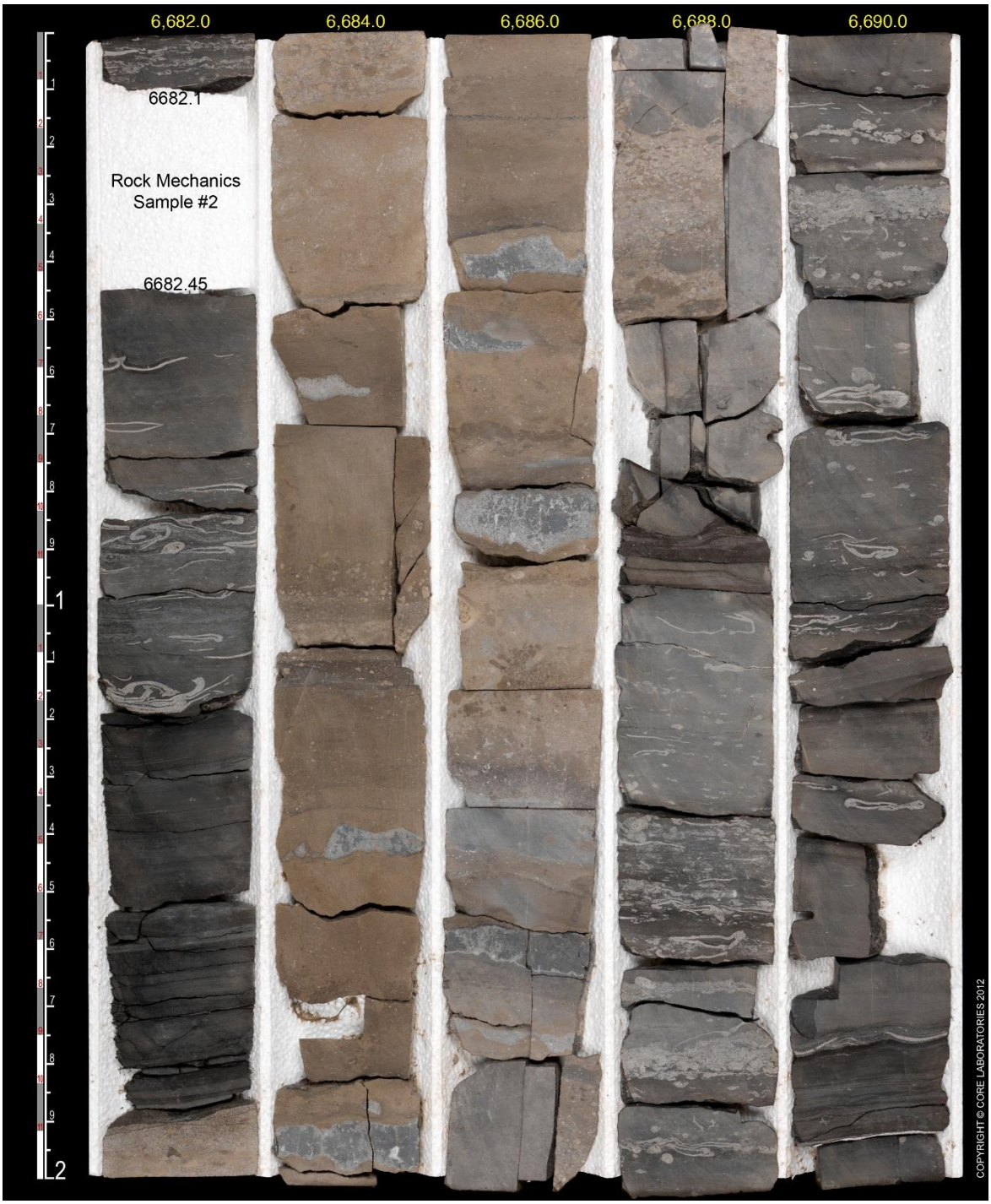


Figure 1. Uteland Butte core from the Bill Barrett 14-1-46 well. The horizontal drilling target is the roughly 5-ft light brown dolomitic interval. Porosity in this interval ranges from 15 to 30% and permeability averages 0.06 mD. The dolomite is interbedded with organic-rich mudstones and limestones averaging between 1 and 3% TOC. Note the abundant shell fragments indicating deposition in a freshwater lacustrine environment.

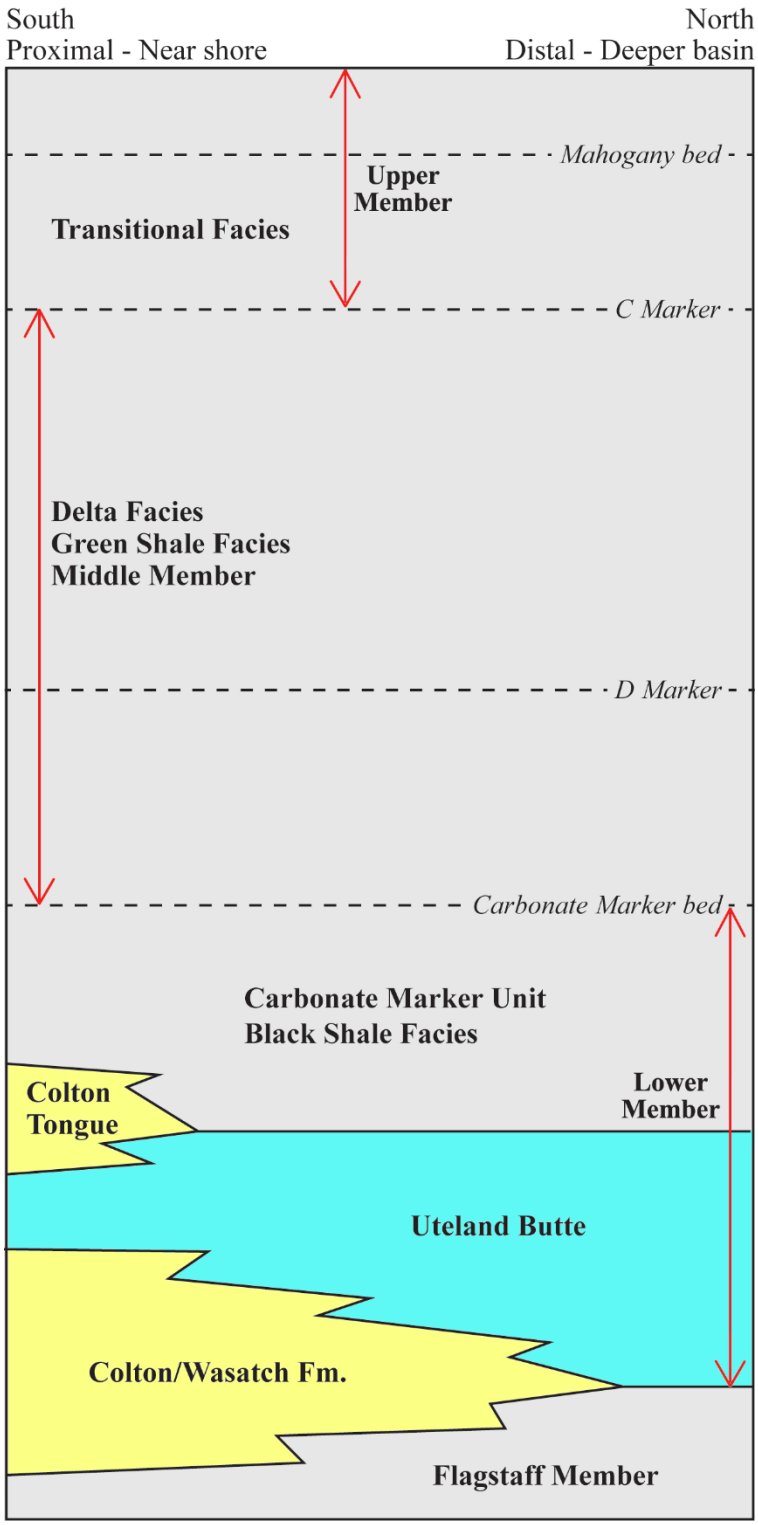


Figure 2. General stratigraphy of the Green River Formation in the western Uinta Basin (not to scale). The Uteland Butte Limestone, the primary horizontal drilling target in the basin, and its relationship to the Colton/Wasatch Formation is shown.

Figure 3. Outcrop of the Uteland Butte Member of the Green River Formation, Nine Mile Canyon, central Utah.


Figure 4. Fresh road cut exposure of Uteland Butte Member of the Green River Formation consisting of interbedded dolomite and mudstone/limestone, Nine Mile Canyon, central Utah.

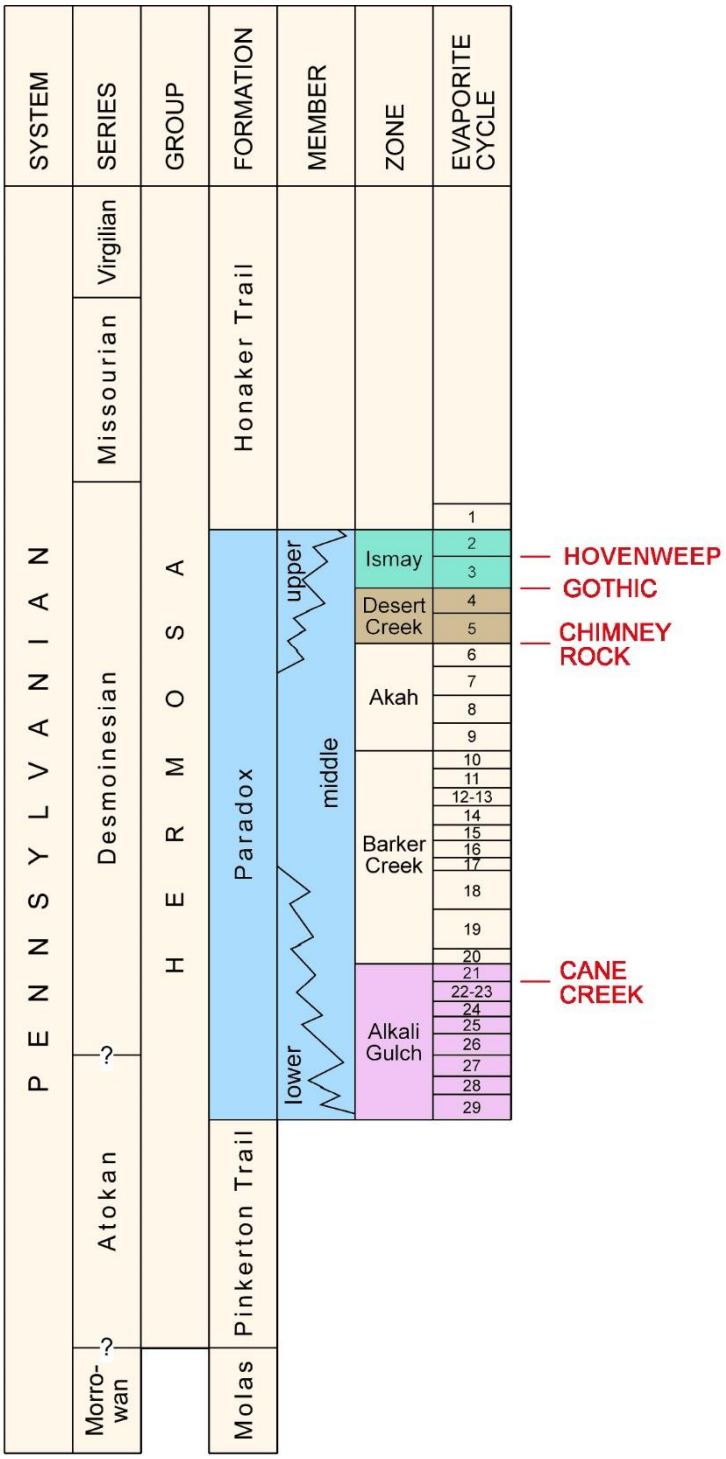


Figure 5. Pennsylvanian stratigraphic chart for the Paradox Basin, informal organic-rich shale units are highlighted. Modified from Hite (1960), Hite and Cater (1972), and Reid and Berghorn (1981).

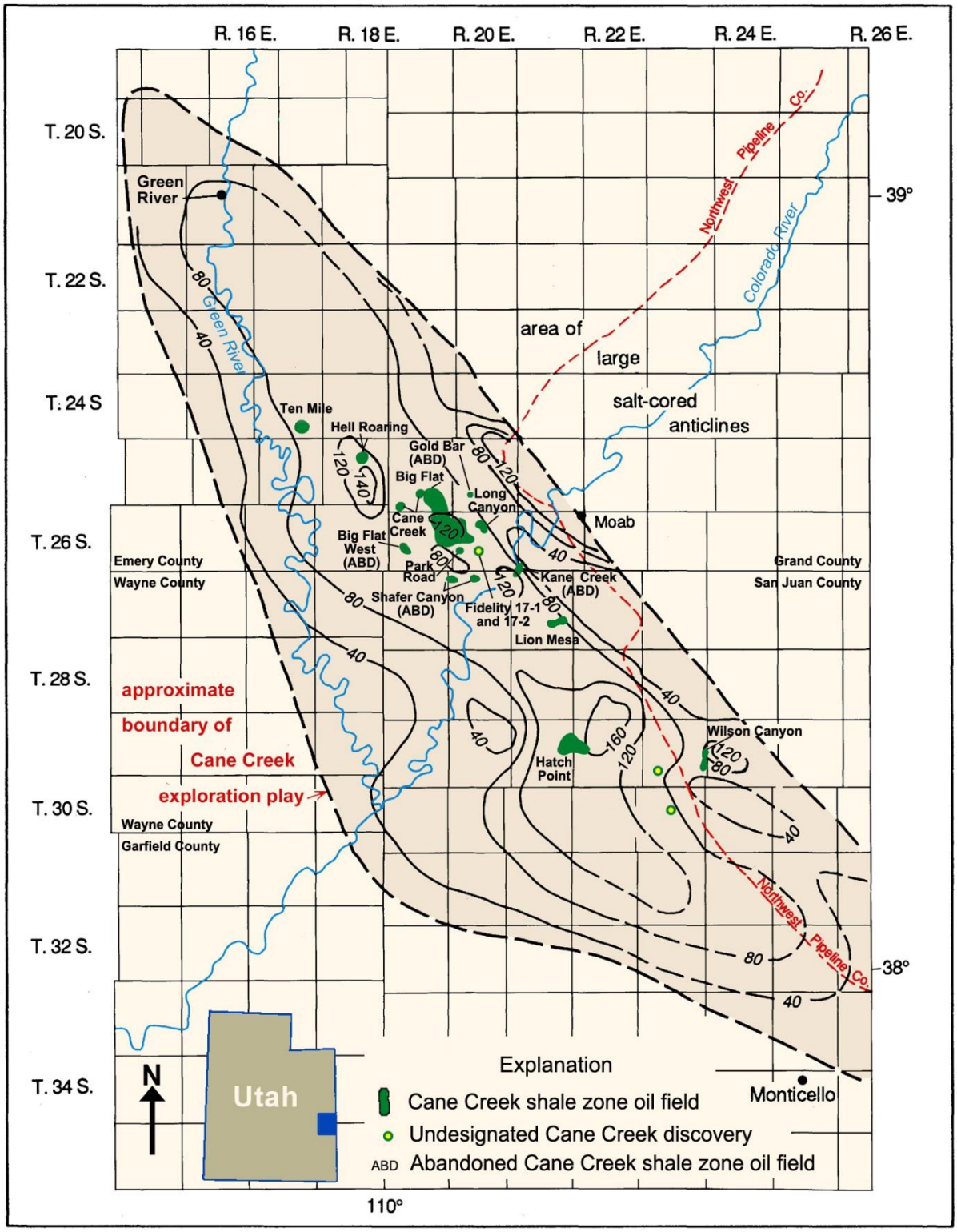


Figure 6. Thickness map and exploration play area of the Cane Creek shale zone of the Pennsylvanian Paradox Formation, northern Paradox Basin, Utah, showing Cane Creek fields. Contour interval = 40 ft. Dashed red line is natural gas pipeline.

Figure 7. Cane Creek shale zone core from the Union Pacific Resources Remington 21-1H well (section 21, T. 31 S., 23 E., SLBL&M, San Juan County, Utah) displays interbedded medium gray dolomite with organic-rich dark gray/black shale. Also present is mottled light gray to white anhydrite.

UTICA SHALE, OHIO, PENNSYLVANIA, WEST VIRGINIA, KENTUCKY

Richard Nyahay, Nyahay Geosciences, LLC, New York

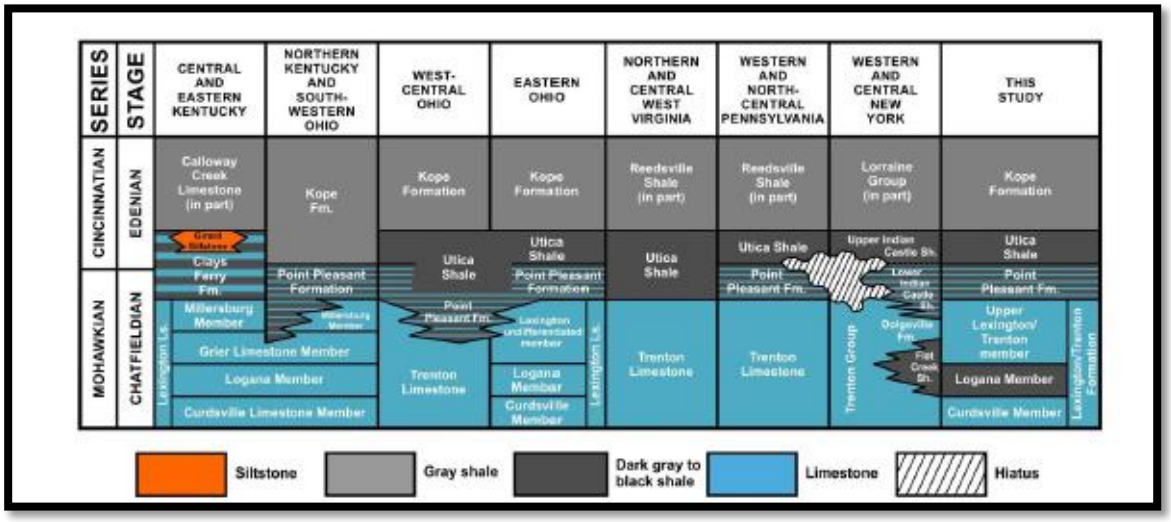
OVERVIEW:

The Ordovician Utica (Indian Castle), Dolgeville, and Flat Creek are the formations of interest. These shales and interbeded limestones range in TOC (Total Organic Content) 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, Pennsylvania, and West Virginia, 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).

In Kentucky, the Utica is equivalent to the Clays Ferry formation and individual members of the Trenton/Lexington formation, one organic rich, the Logana member and the other organic poor, the Curdsville member.

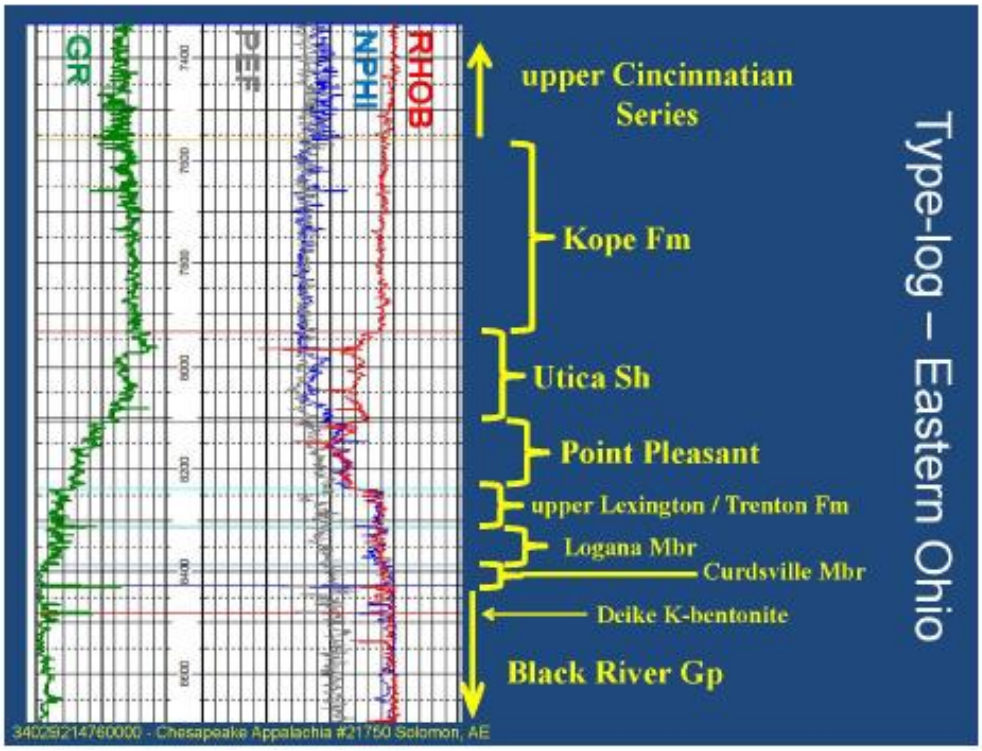
In Michigan, the Utica is underlain by the Collingwood Formation in the northern central part of the state. This formation consist of shales that are black to brown and dark gray in color, with a thickness between 25 to 40 feet and TOC range between 2-8 percent (Snowdon, 1984).



(Patchen, D.G. and Carter, K.M., 2015)

Correlations from the Utica outcrop sections in the Mohawk Valley to subsurface in Ohio, Pennsylvania, Kentucky, and West Virginia would be as follows: the Lorraine to Upper Indian Castle would be equivalent to the Kope Formation, Lower Indian Castle would be equivalent to the Utica, the Dolgeville would be equivalent to the Point Pleasant, the Flat Creek would be equivalent to the Logana (Smith, 2015). See the type log for the Utica section below.

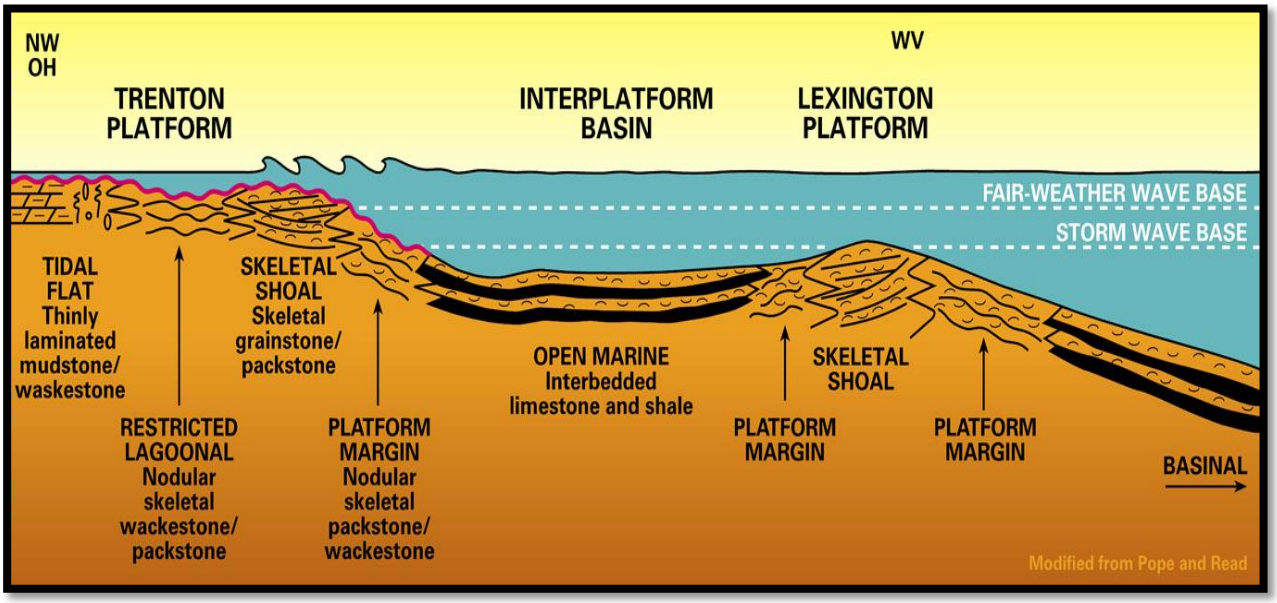
The Kope Formation is an organic poor interbedded gray shale and siltstone. The Utica Formation would be a laminated organic and clay rich shale with thin limestone beds. The Point Pleasant Formation is an interbedded limestone and shale, the upper section would be organic poor, and the lower section is a storm-bedded and laminated black shale and limestone. The Logana Formations is an organic rich interbedded calcareous shales and limestones with abundant ostracods in the organic facies.



(Patchen, D.G. and Carter, K.M., 2015)

GEOLOGY:

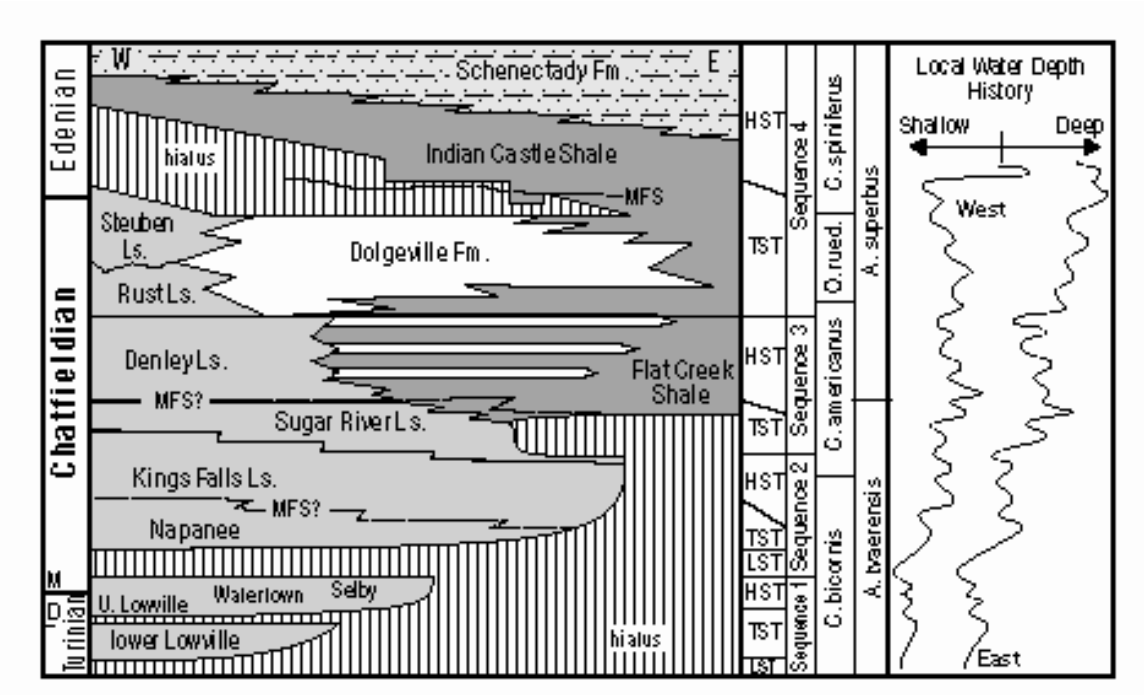
The Late Ordovician Utica shale was deposited in a foreland basin setting adjacent to and on top of, the Trenton and Lexington carbonate platforms. Initial deposition of the Trenton and Lexington platform began on a relatively flat Black River passive margin. Early tectonic activity from the Taconic orogeny created the foreland bulge that would become the Trenton and Lexington platforms. Carbonate growth was able to keep up with the overall rise in seal level while areas stayed relatively deeper until increased subsidence in the foreland basin lowered the ramps out of the photic zone and inundated the passive margin with fine grained clastics (Willan et al. 2012).



(Riley & Baranowski, 2011)

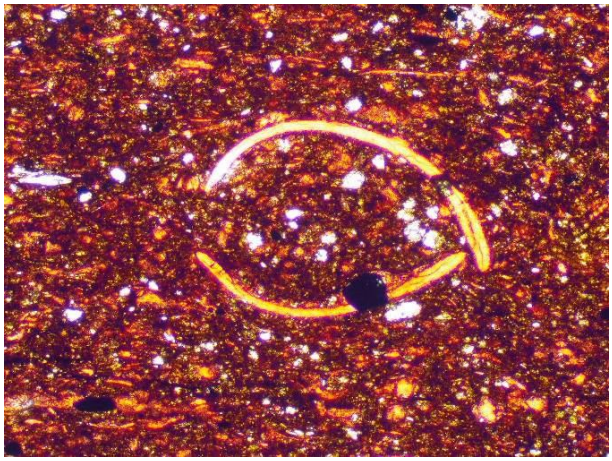
The Trenton/Lexington limestone through the Utica Shale comprise the trangressive systems tract (TST) of a large second-order sequence, superimposed with four, smaller scale third-order composite sequences. Third order sequences are

regional correlative, aggradational, and lack lowstand deposits. Sequences are separated by type 3 sequence boundaries that amalgamate with trangressive surfaces and separate underlying highstand system tracts(HST's) from overlying TST's(McClain, 2012).



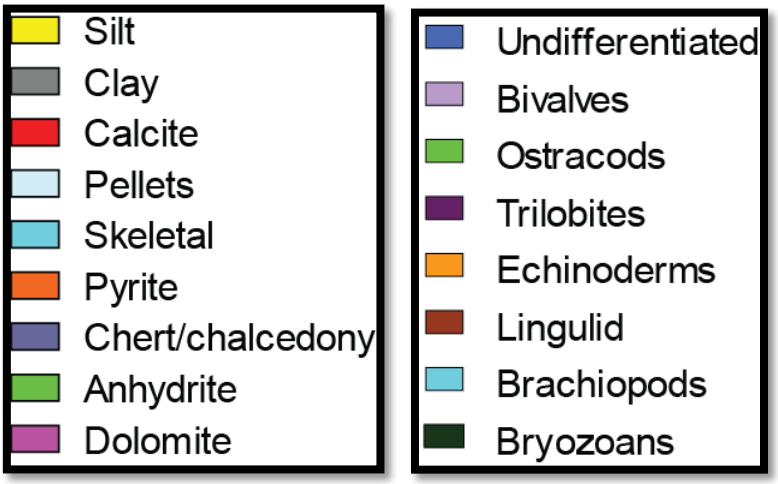
(Joy et al. 2000)

Smith, 2013 proposes the organic rich section were deposited in shallow water to the west and becomes progressively less organic rich approaching what was the deepest part of the basin due to progressively more dilution from clay and silt that are sourced from the highlands to the east, but it may be the longest duration of anoxic conditions occurred in the shallowest water. The environment was relatively shallow, less than 30 meters deep, with storm dominated carbonate shelfs that experienced frequent algae blooms. A study of five cores taken in Ohio show an abundance of fossils that indicates the environment was oxygenated much of the time. There are delicate trilobites and articulated ostracods that could not have been transported any significant difference. The silt sized skeletal debris was probably reworked and of unknown origin. A core description from one of the five cores below (Smith, 2015a).

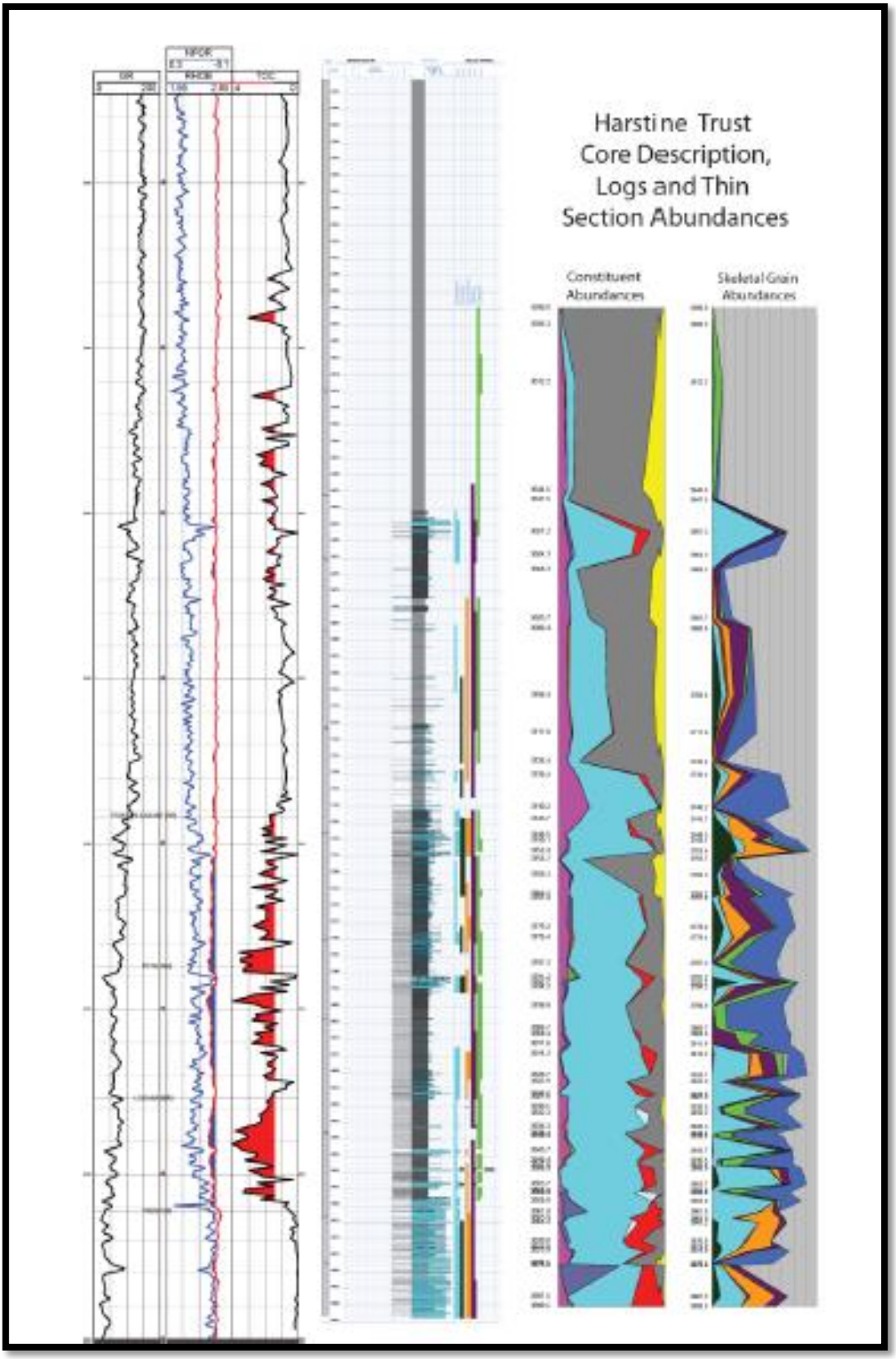


(Smith, 2015a)

An ostracod in organic rich Logana member of the Lexington Formation.

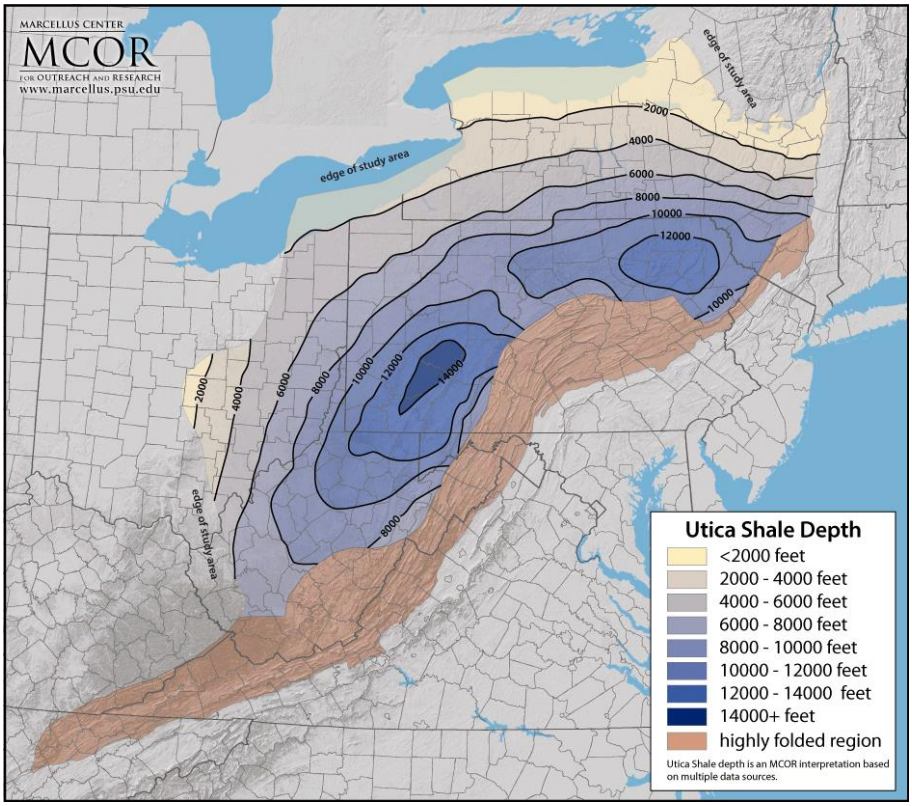


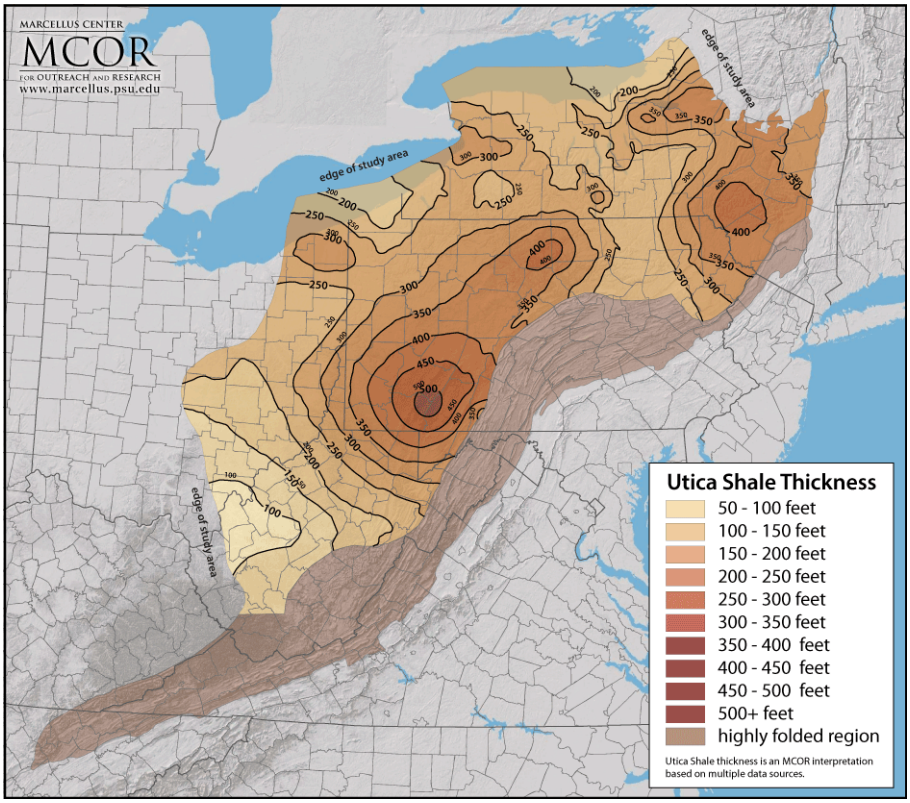
Descriptions for graphs below



(Smith, 2015a)

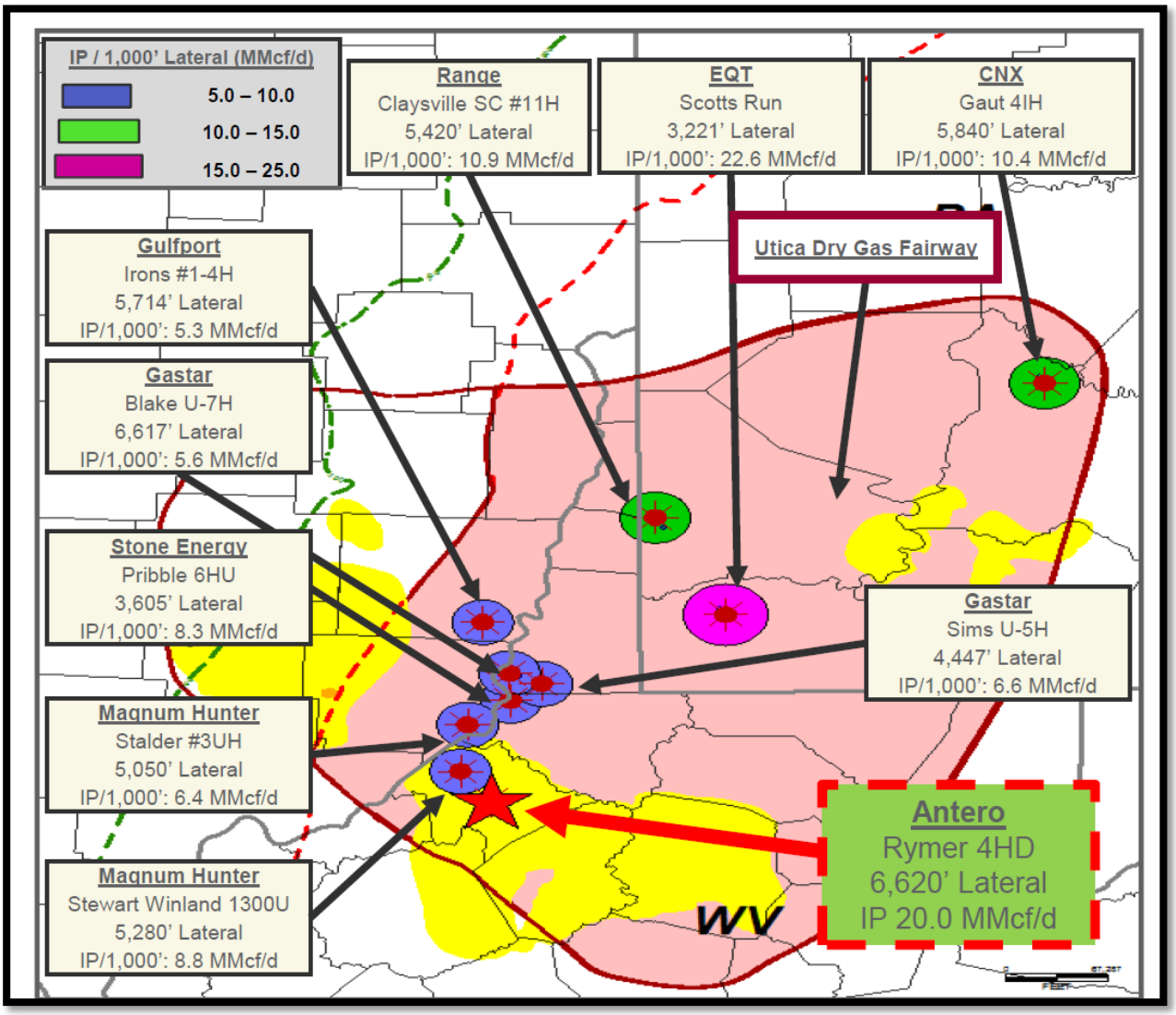
One of the five Devon Cores studied in Ohio





General Maps of the Utica

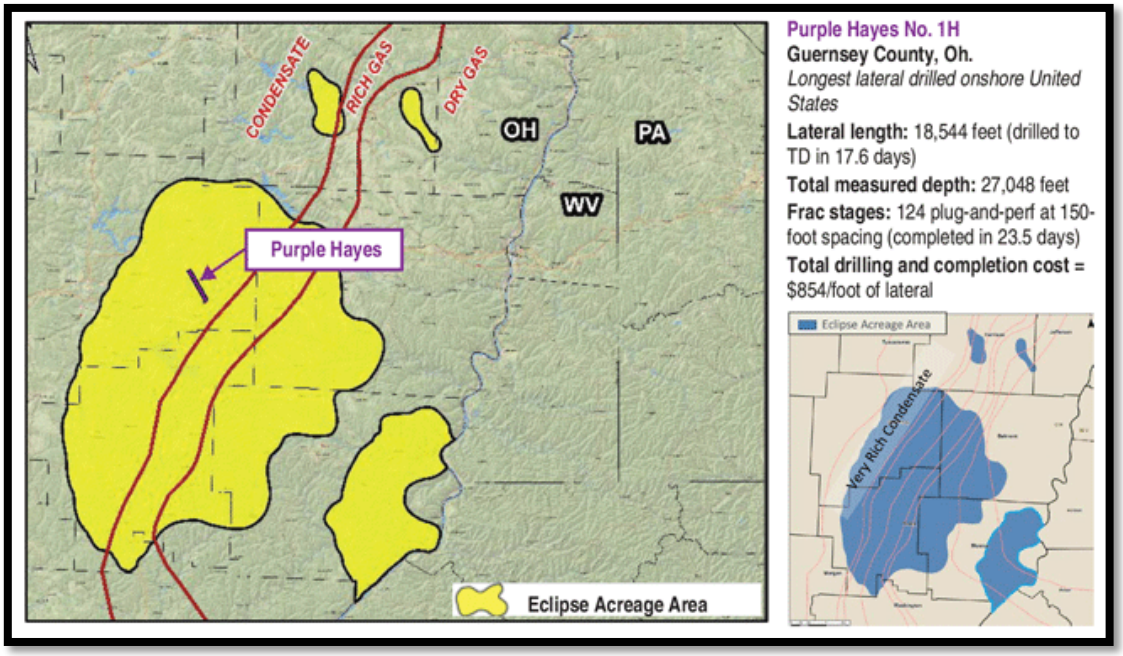
Well Activity:



(Antero Resources Company Presentation, 2016)

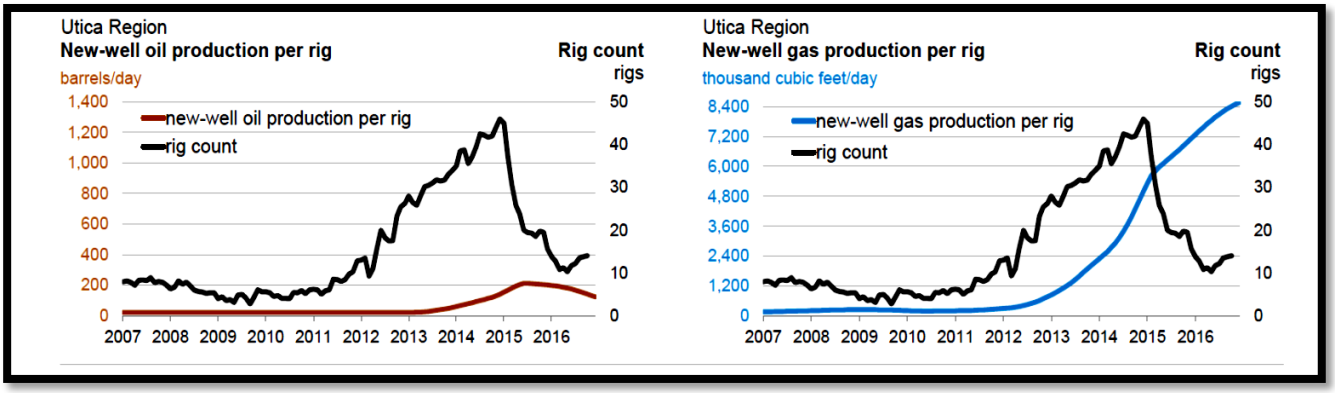
With the current regulatory moratorium in place in New York, activity has been focused in eastern Ohio, western Pennsylvania and western West Virginia. No drilling has been done in Kentucky to date. Ohio current drilling activity as of December 3, 2016 lists 2319 Utica permits, 1860 wells drilled and 1327 producing wells (ODNR, 2016). Exploration activity has been concentrated in a triangle area of southeastern Ohio, the northern pan handle of West Virginia and southwestern Pennsylvania. The map above highlights the area of the best producing Point Pleasant wells.

In May, Eclipse Resources Corporation drilled the Purple Hayes 1H well, the longest lateral ever drilled onshore in the United States. The length of the lateral was 18,544 feet, it was completed in 24 days and produces natural gas and condensate. Initial Production from the Purple Hayes 1H is 5 million cubic feet per day and 1,200 barrels of condensate a day. Compared to earlier wells Eclipse has drilled, the superlateral Purple Hayes 1H has three times the reservoir interval than those of the first 10 horizontals at one third the cost and in less time than 7,000 foot laterals drilled earlier (Beims, 2016).



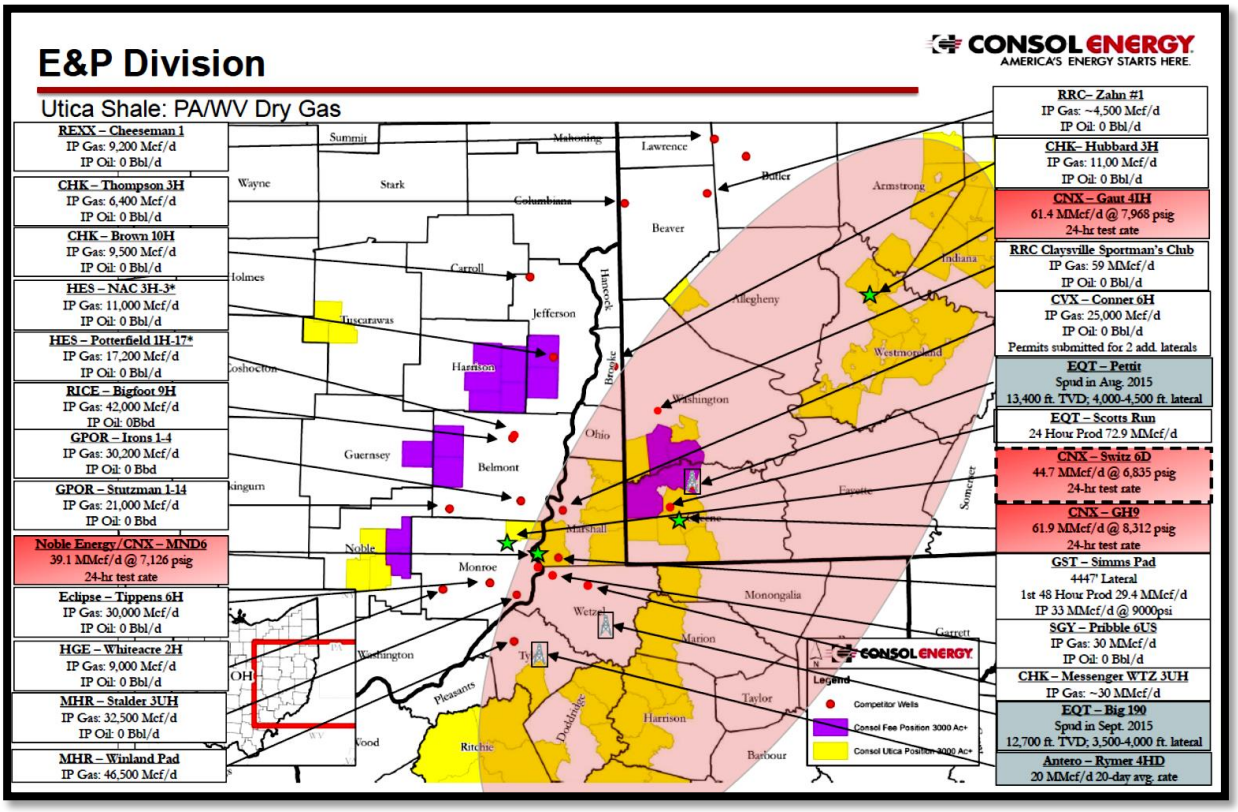
(Biems, 2016)

Most of the activity has taken place in Eastern Ohio. Chesapeake Energy is the operator who has the majority of permits. Shell Appalachia has concentrated their efforts in the dry gas area in Pennsylvania from Lawrence County eastward to Tioga County and has permitted 75 Utica/Point Pleasant horizontal wells. Of these, 18 are reported as completed, two are drilled or drilling, and 55 are not drilled. There are no annual production data available for these wells.

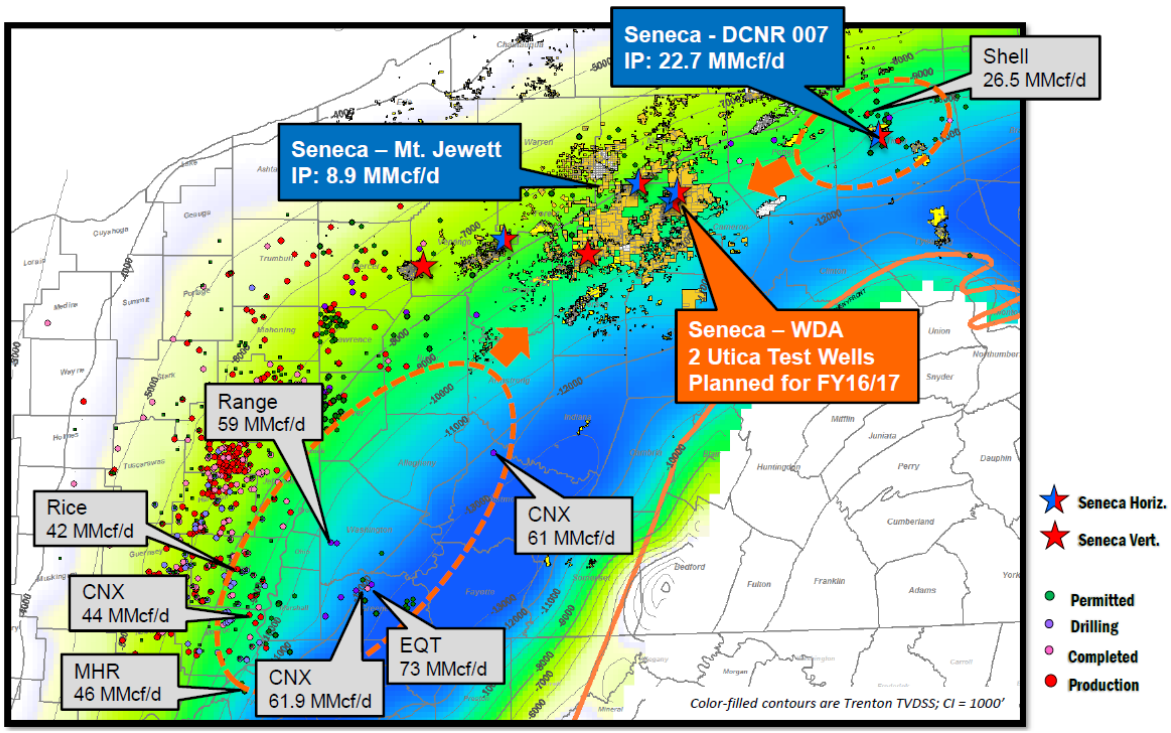


November statistics for Utica Region from EIA 2016

Pennsylvania and West Virginia Activity:

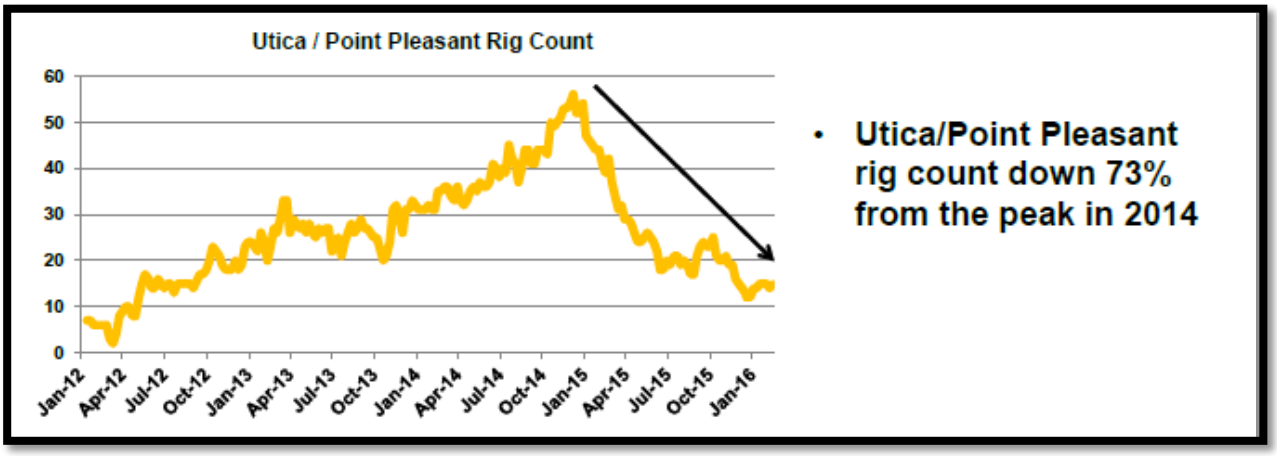


(Consol Energy, 2016)



(National Fuels, 2016)

Drilling rigs counts are reflecting stagnant natural gas prices, low demand and excess supply. As of December 2016, 18 rigs were operating in Ohio with fewer wells to be drilled Pennsylvania and West Virginia. Gulfport Energy in response to decreased commodity prices is shifting its lateral spacing from 600 to 1000 feet to increase acreage held by production and minimize leasehold costs (Gulfport Energy, 2016).



(Range Resources, 2016)

The table below lists some of the major companies and their net acreage in the Utica in 2014.

Company	Ticker	Net Acres
Chesapeake Energy	CHK	1,000,000
Chevron	CVX	600,000
Anadarko Petroleum	APC	267,000
Devon Energy	DVN	195,000
Range Resources	RRC	190,000
Hess Corporation	HES	185,000
EV Energy	EVEP	177,000
Gulfport Energy	GPOR	147,350
Halcon Resources	HK	142,000
Antero Resources	AR	104,000
Magnum Hunter	**MHR**	**99,000**
BP	BP	84,000
Consol Energy	CNX	80,000
ExxonMobil	XOM	75,000
PDC Energy	PDCE	48,000
Carrizo Oil & Gas	CRZO	21,700
Rex Energy	REXX	21,000
EQT Resources	EQT	13,600

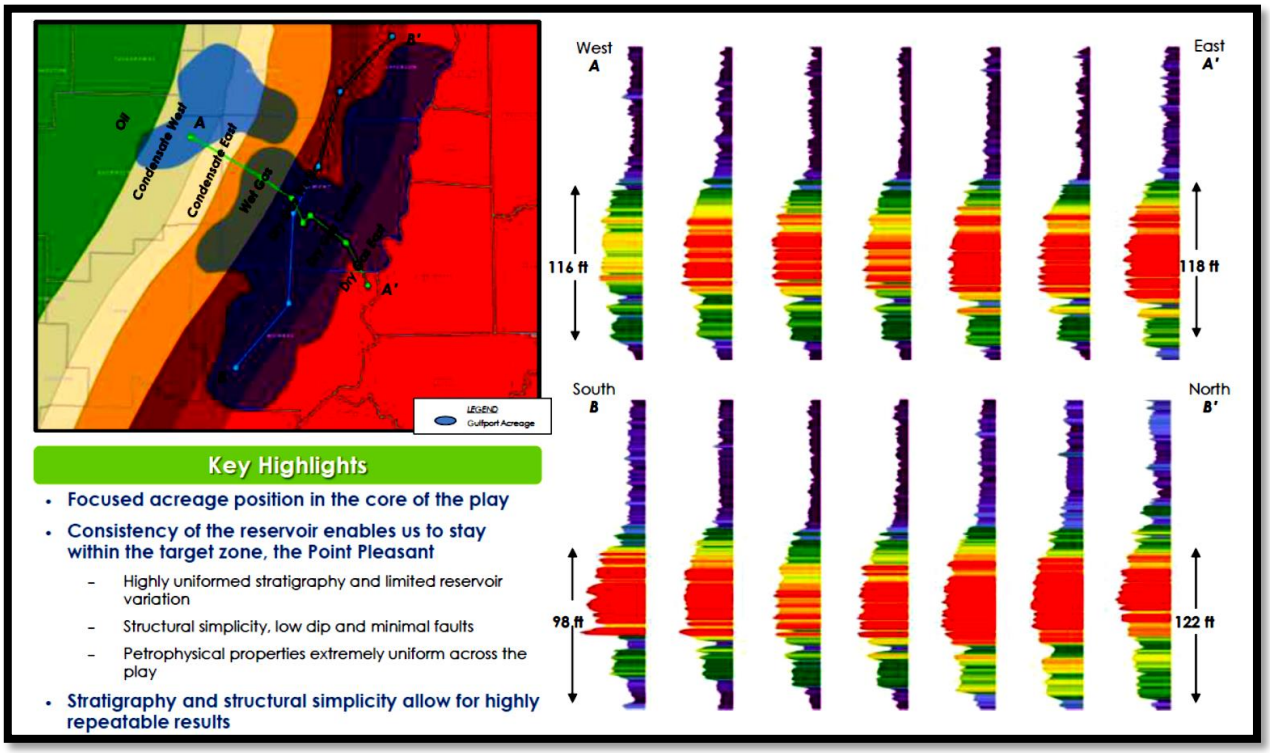
(Magnum Hunter Resources, 2014)

Best Well Attributes: EQT's Scott Run comes in at the highest IP rate thus far in the dry gas window of the Utica/Point Pleasant play with an initial 24 hr. IP of 72.9 MMcf/d. Two Consol Energy wells GH9 and Gaut 4IH are just below with initial 24 hr. IP's of 61.9 and 61.4 MMcfp/d. From the table below lateral length ranges from 3221 to 6957 feet though increasing IP is not correlating with increasing lateral length. From the Seneca Resources Presentation map above seems to indicate that increasing depth plus with 5,000 foot laterals equal better producing wells. The Gulfport cross sections show the stratigraphy and petrophyical properties of the Point Pleasant are uniform and are structurally quiet. This would speak to the success Eclipse Resource Corporation is having with its superlateral Purple Hayes 1H. Eclipse Resources corporation research believes it could drill a 22,000 foot lateral well effectively.

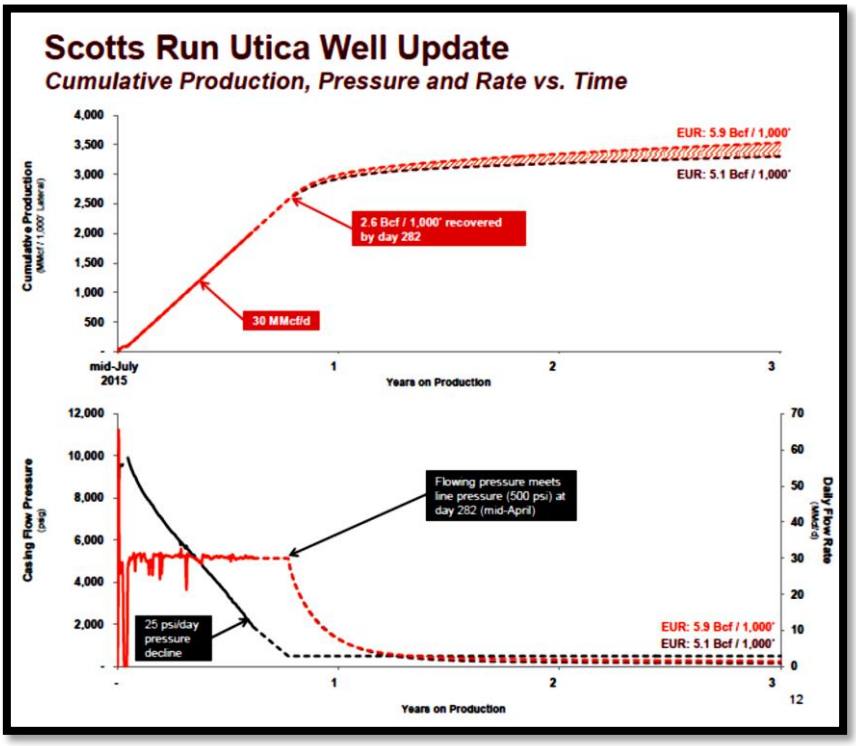
Well	Operator	24-hr IP (MMcf/d)	Lateral Length (Ft)	24-hr IP/1,000' Lateral (MMcf/d)
Scotts Run	EQT	72.9	3,221	22.633
Gaut 4IH	CNX	61.0	5,840	11.131
CSC #11H	RRC	59.0	5,420	10.886
Stewart-Win 1300U	MHR	46.5	5,289	8.792
Bigfoot 9H	RICE	41.7	6,957	5.994
Blank U-7H	GST	36.8	6,617	5.561
Stalder #3UH	MHR	32.5	5,050	6.436
Irons #1-4H	GPOR	30.3	5,714	5.303
Pribble 6HU	SGY	30.0	3,605	8.322
Simms U-5H	GST	29.4	4,447	6.611
Conner 6H	CVX	25.0	6,451	3.875
Messenger 3H	SWN	25.0	5,889	4.245
Tippens #6H	ECR	23.2	5,858	3.960
Porterfield 1H-17	HESS	17.2	5,000	3.440

(Antero Resources Company Presentation, 2016)

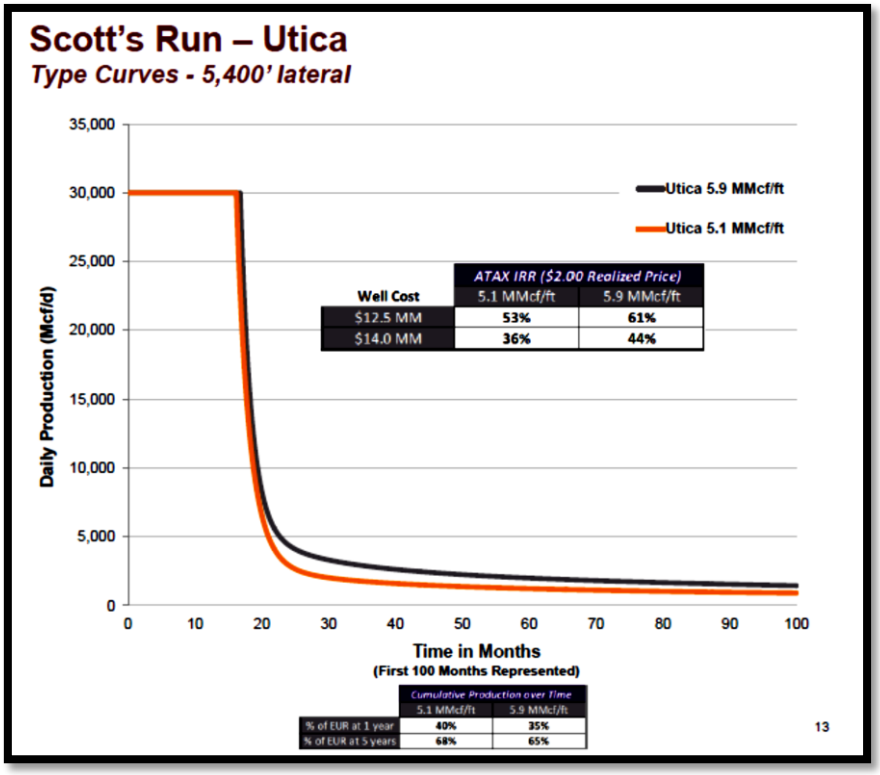
Uniform Stratigraphy and Petrophysical Properties



(Gulfport Presentation, 2016)



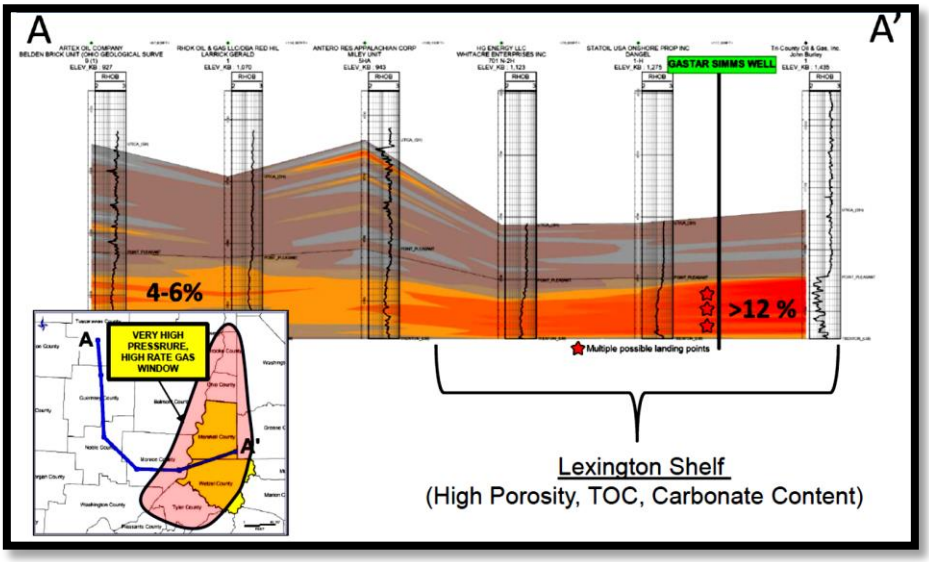
(EQT, 2016)



(EQT, 2016)

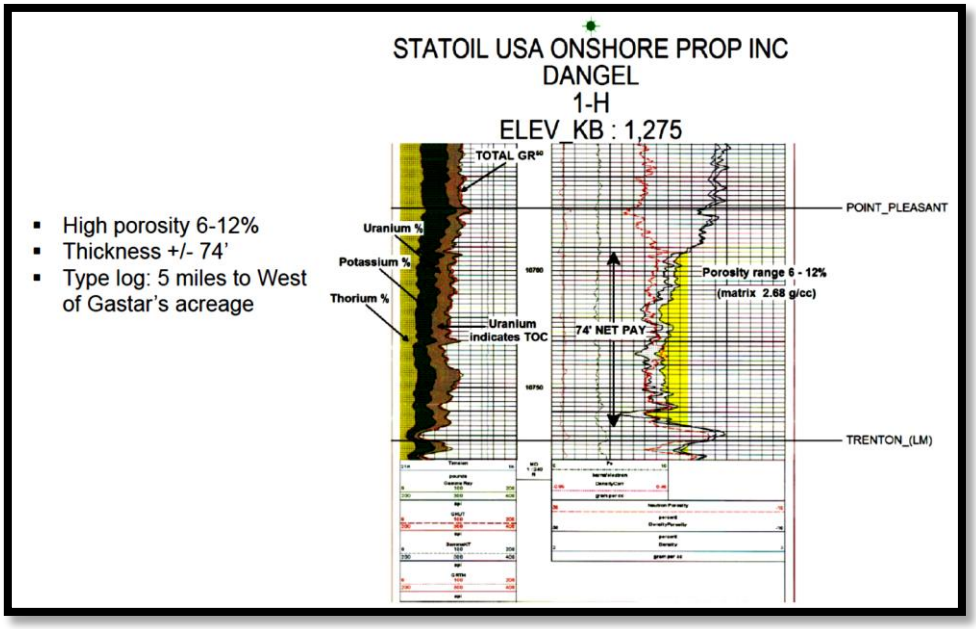
Above are type curves for EQT's Scott Run well drilled in Greene County PA with 18 fracture stages on a 3,221 foot lateral. If you inspect the cross-section below closely it shows the density logs decreasing as wells trend to the east in the Point Pleasant sweet spot. With decreasing density logs, the TOC content increases. With TOC greater than 12 % in some of these wells, production must be related to TOC. From Gastar type log (Dangle 1H) in Monroe County, Ohio, the lower density log values correlate to increasing TOC.

Cross-section of wells with very high pressure and high gas rates.



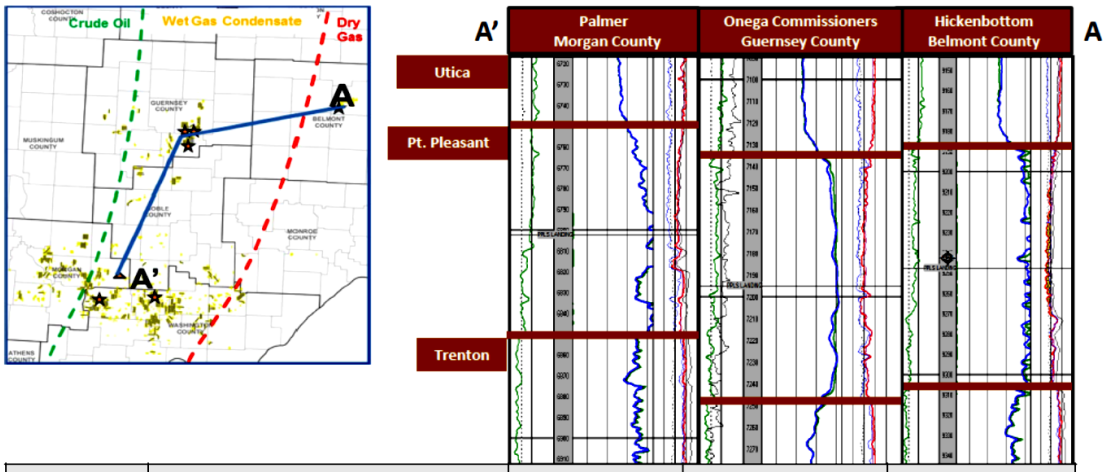
(Gastar Exploration Inc., 2014)

Gastar's Exploration type log in Monroe County, Ohio for the Simm's Well in West Virginia.



(Gastar Exploration Inc, 2014)

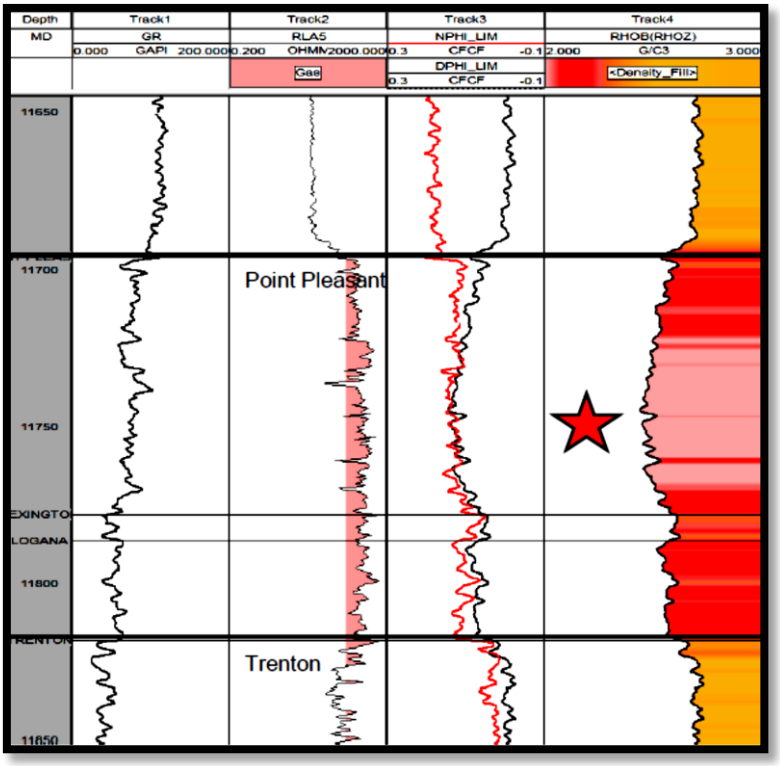
All logs in the highlighted southeastern Ohio, PA and West Virginia area all show increasing resistivity and decreasing density which correlates to higher TOC values and increasing porosity.



Average Rock Properties PDC Acreage	Palmer Morgan County	Onega Commissioners Guernsey County	Hickenbottom Belmont County
Resistivity (ohm-m)	800 – 2,000	1,000 – 2,000+	1,000 – 2,000+
Porosity (%)	6 - 11%	6 - 12%	6 - 13%
Thickness of Pt. Pleasant (ft)	100'	112'	117'
Total Organic Content (TOC)	Max 4.4	Max 4.8 (est.)	Max 4.5
Formation Depth (ft)	6,750' – 6,850'	7,135 – 7,247	9,188' – 9,305'
BTU of gas stream	1,261	1,254	1,040

(PDC Energy, 2014)

Log from Range Resources in Washington County, PA with an IP of 59 mmcfd with 32 stage 5420 feet lateral completion



(Range Resources, 2015)

Most of the gas in place is in free gas, according to Range Resources 20% to 40 % more than best areas in eastern Ohio.

	GAS IN PLACE ANALYSIS: Claysville Sportsman 11H				
		Bulk Density (g/cc)	Gas Content (scf/ton)	GIP (scf/acre-ft)	GIP (BCF/section)
Utica to Trenton	Free Gas	2.64	240.4	863,811	140.9
	Sorbed Gas		23.5	84,488	13.8
	Total Gas in Place		263.9	948,299	154.7
	GAS IN PLACE ANALYSIS: Claysville Sportsman 11H				
		Bulk Density (g/cc)	Gas Content (scf/ton)	GIP (scf/acre-ft)	GIP (BCF/section)
Utica	Free Gas	2.73	148.2	549,663	46.3
	Sorbed Gas		9.9	36,534	3.1
	Total Gas in Place		158.1	586,197	49.3
	GAS IN PLACE ANALYSIS: Claysville Sportsman 11H				
		Bulk Density (g/cc)	Gas Content (scf/ton)	GIP (scf/acre-ft)	GIP (BCF/section)
Point Pleasant	Free Gas	2.56	338.5	1,177,676	93.0
	Sorbed Gas		38.1	132,404	10.5
	Total Gas in Place		376.5	1,310,080	103.5

(Range Resources, 2015)

With high gas in place values, Range Resources is also reporting highest pressure gradients along South East Ohio, the pan handle of West Virginia and south western Pennslyvania.

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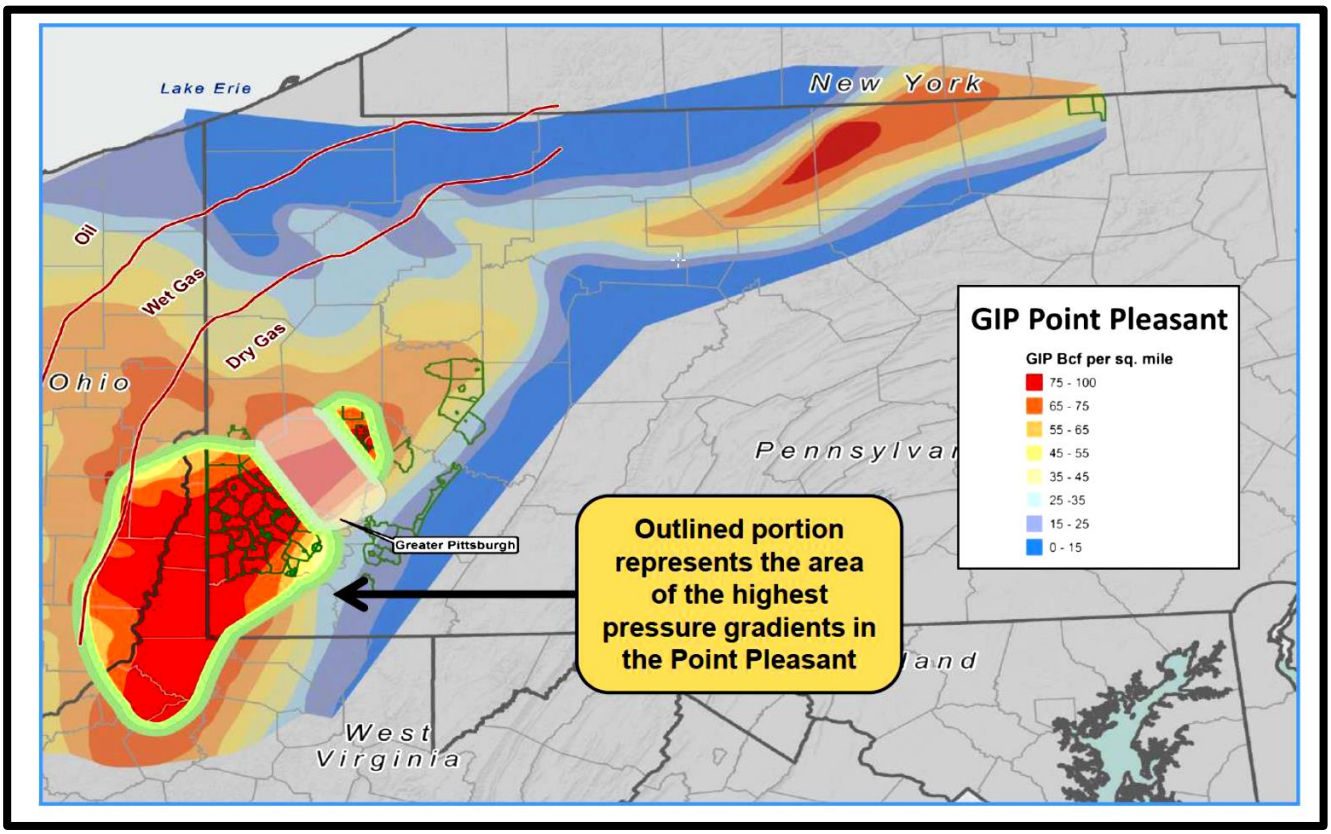


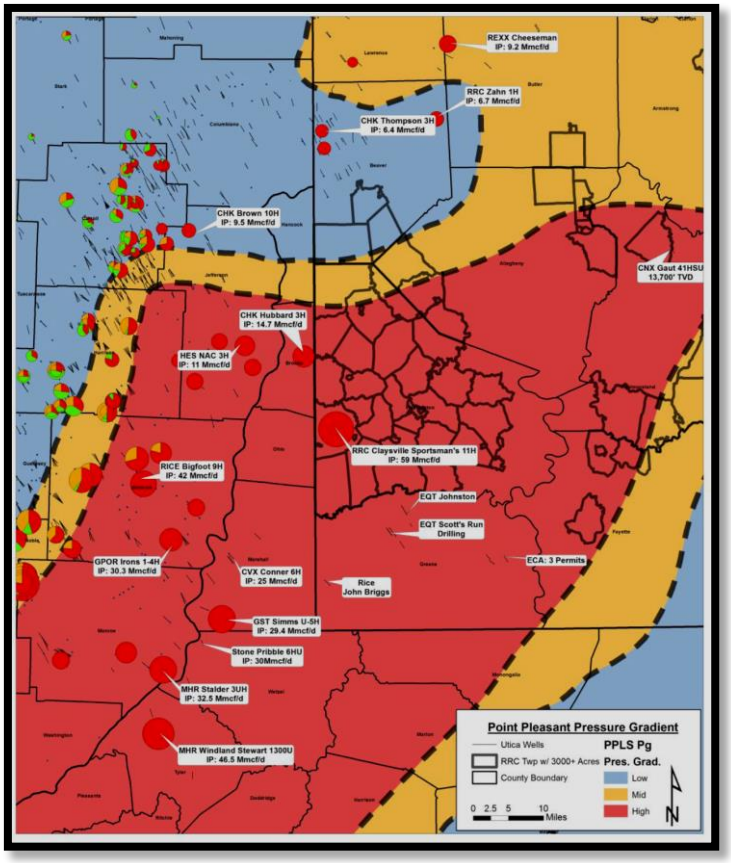
(Range Resources, 2015)

Table of Pressure Gradients for States

State	Pressure Gradient (psi/ft)		Note(s)
	Low	High	
New York (NY)	0.433	0.5	0.433 for most of NY; 0.5 for very small portion of southern NY
Ohio (OH)	0.6	0.9	0.6 for most of OH; 0.7-0.9 for narrow region in east central OH
Pennsylvania (PA)	0.6	0.9	0.6 for most of PA; 0.7 in small portion of central PA; 0.7-0.9 in southwestern PA
West Virginia (WV)	0.6	0.9	0.6 for most of WV; 0.7-0.9 for northern WV panhandle

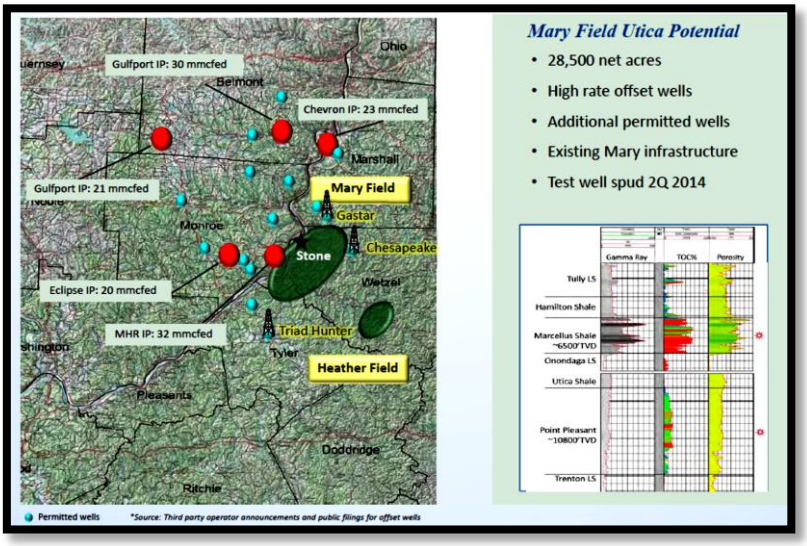
(Patchen, D.G. and Carter, K.M., 2015)

Below is a graphic from a Range Resources presentation delineating pressure gradients found in the area with high volume wells. Pressure gradients have been reported to be 0.94 and higher.



(Range Resources, 2015)

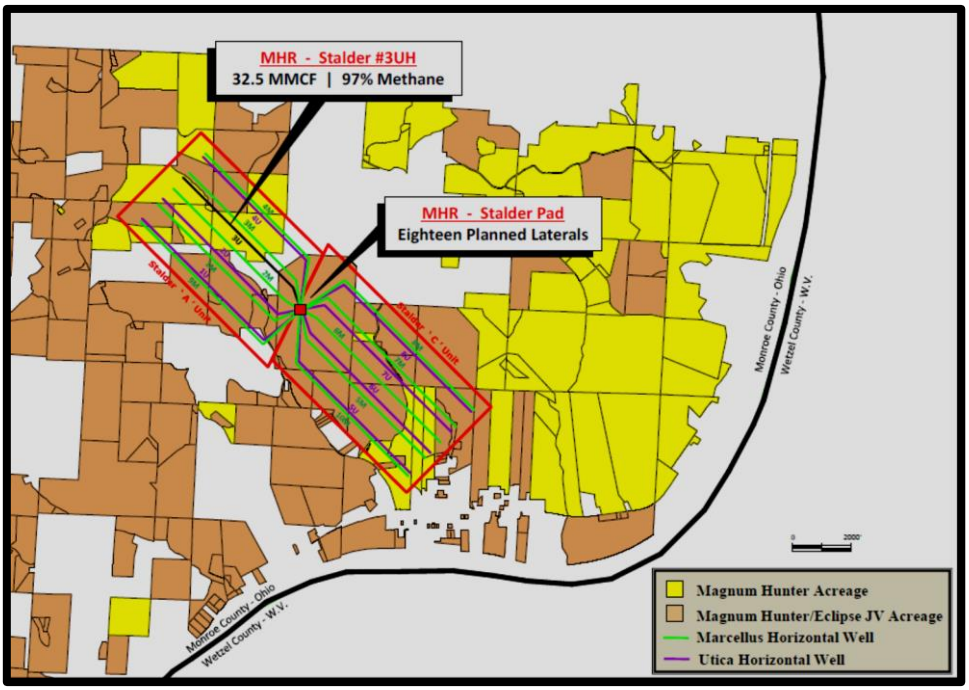
Stone Energy also had a successful test in Wetzel County, WV extending the high IP and pressure gradient area and possibly looking to extend the area further to the southeast.



(Stone Energy, 2014)

Stackable Reservoirs:

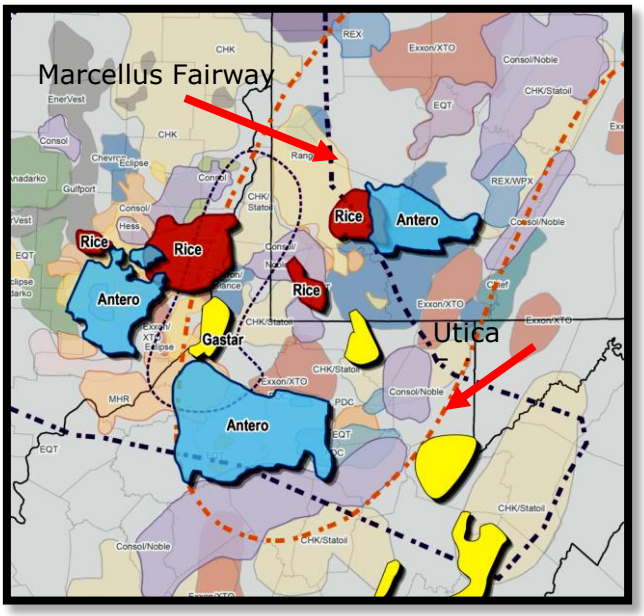
Magnum Hunter Resources has been exploiting this area with stackable reservoirs most notably the Ordovician Utica and Devonian Marcellus see the design below in Monroe County, Ohio.



(Magnum Hunter Resources Inc., 2014)

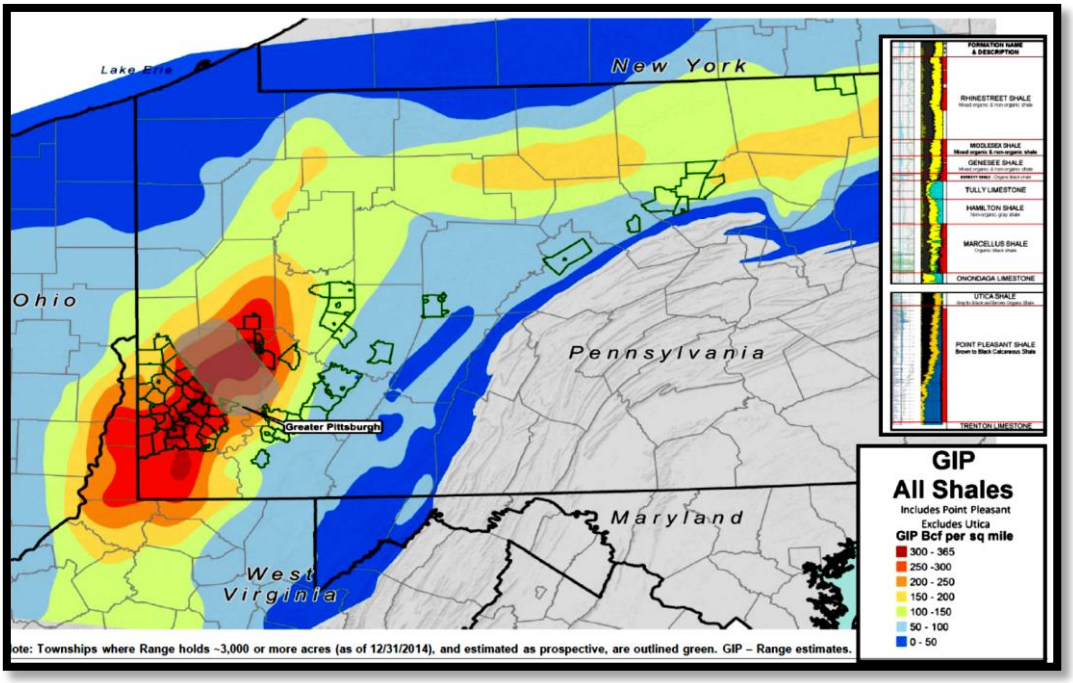
The Consol Energy Gaut 4IH well in Westmoreland County, PA, one of the top three Utica producers, was drilled off the Gaut pad, which includes seven Marcellus wells (Pickett, 2015).

Companies with acreage in stackable play area

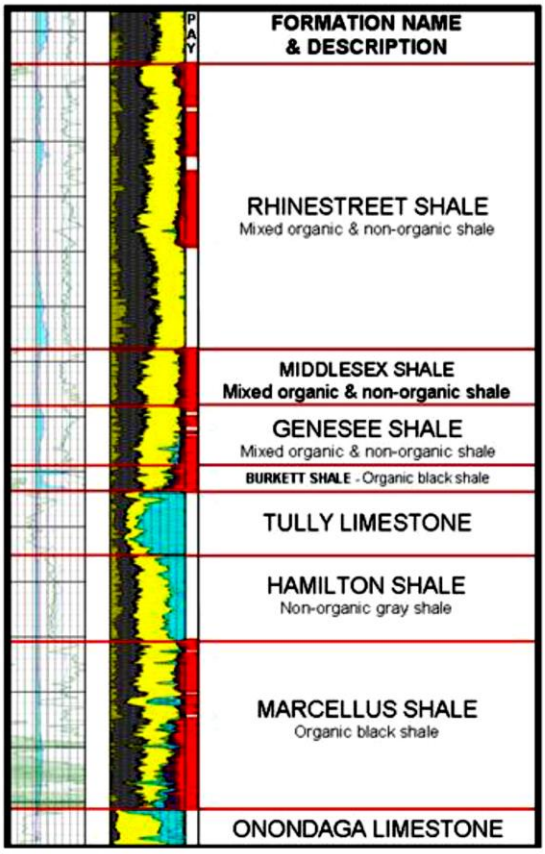


(Gastar Exploration Inc., 2014)

Gas in place estimates for stackable plays from Range Resources.



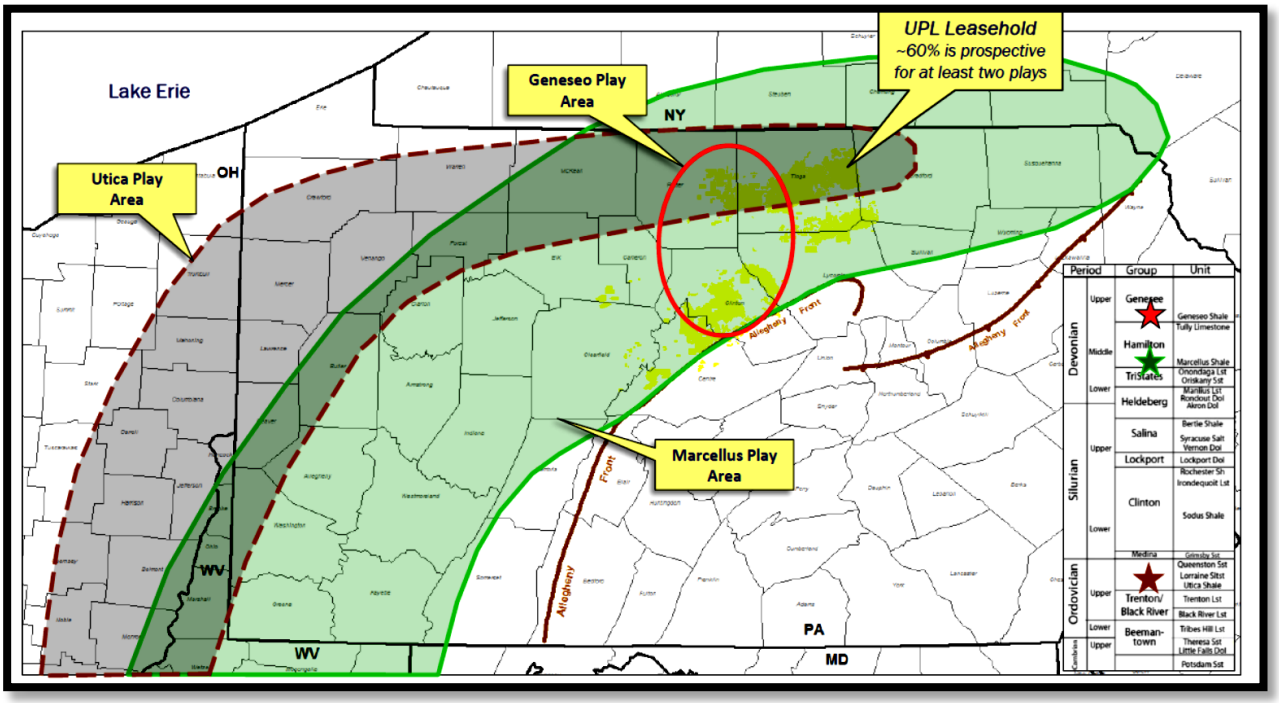
(Range Resources, 2015)



(Range Resources, 2015)

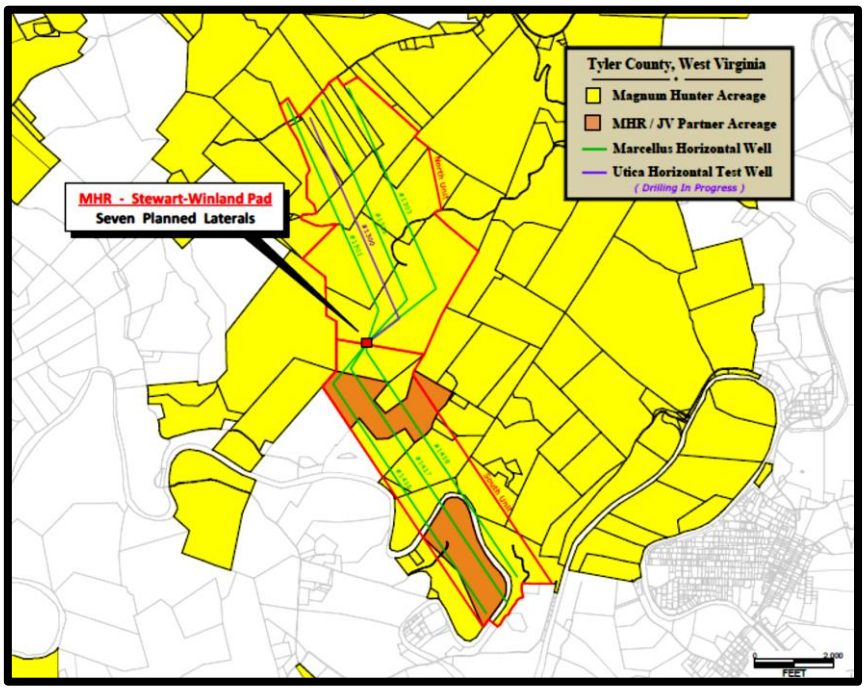
Stratigraphic Section and Log responses formations targeted.

The figure below indicates where the Genesee play area might be located.



(Ultra Petroleum Corp., 2014)

In Tyler County, WV Magnum Hunter Resources had successful tests in the Marcellus and Utica to extend the stackable reservoirs further south and east.



(Magnum Hunter Resources Inc., 2014)

Infrastructure:

Earlier expectations have been dampened by larger companies selling large acreage parcels, pipeline infrastructure not in place, and construction of gas processing units. This concern may be changing because at the current activity has doubled the number of producing wells again

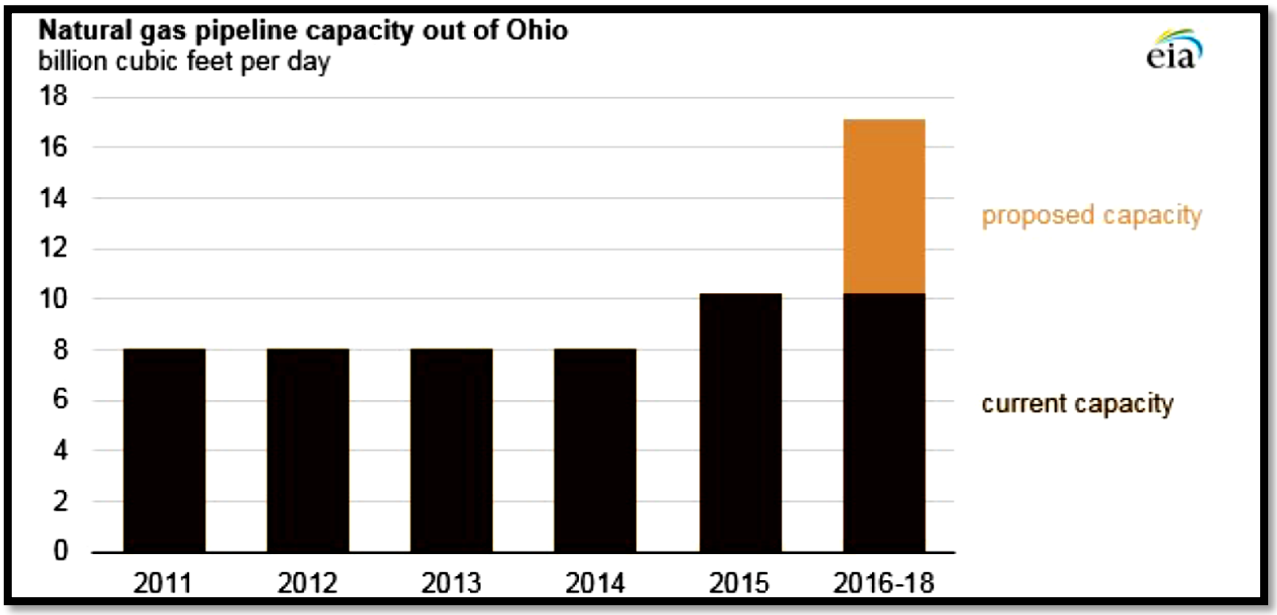
from the latest 3rd quarter production reports of 2013. Three cryogenic natural gas plants have been added in Columbia, Harrison, and Noble counties to separate and purify natural gas. (Downing, 2013).

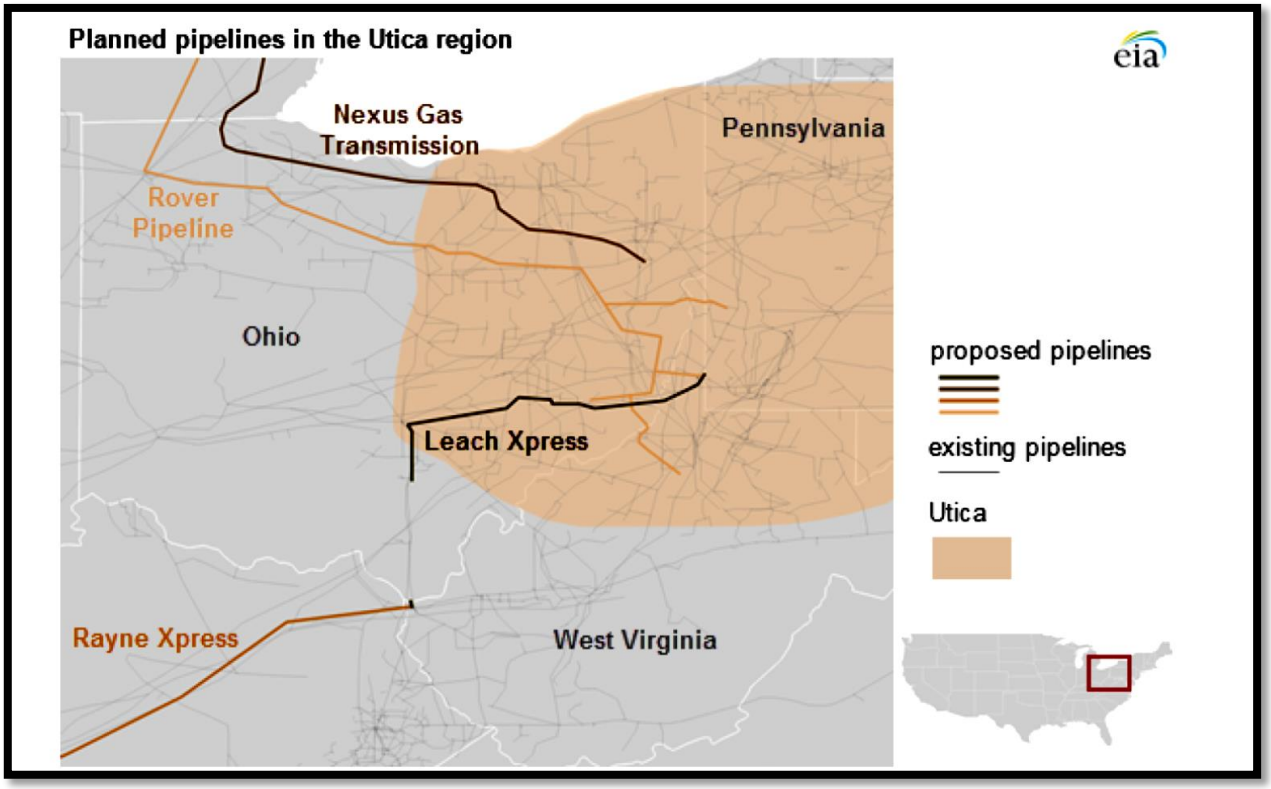
Since pipeline projects take time to be approved, transport infrastructure for accessing natural gas demand centers and export locations in the Appalachian Basin has not kept pace with production capability. This has resulted in a lower price for natural gas from the Appalachian region as compared to other natural gas trading hubs (EIA, 2016).

Kinder Morgan Energy Partners LP and Mark West Energy Partners LP and planning a Utica-Marcellus Pipeline to Texas. This project has a target date of second quarter 2016. Spectra Energy Corp is also planning a Utica to Gulf Coast pipeline to operational by November 2015 (Knox, 2014).

Four key projects undergoing FERC review in Ohio are the Rover pipeline, the Leach Xpress project, the Rayne Xpress Project and the Nexus Gas Transmission project.

The Rover pipeline is designed to transport 3.25 Bcf/d of natural gas to various market hubs. The Leach Xpress project seeks to add 1.5 Bcf/d natural gas takeaway capacity along Columbia Pipeline Group's network. The Rayne Xpress project seeks to add 0.6 Bcf/d in takeaway capacity from Columbia Pipeliene system to Gulf Coast markets, which will facilitate liquefied natural gas exports. The Nexus Gas Transmission project will deliver 1.5 Bcf/d of natural gas to markets in northern Ohio, southeastern Michigan, the Chicago Hub in Illinois, and Dawn Hub in Ontario, Canada (Krohn, 2016).





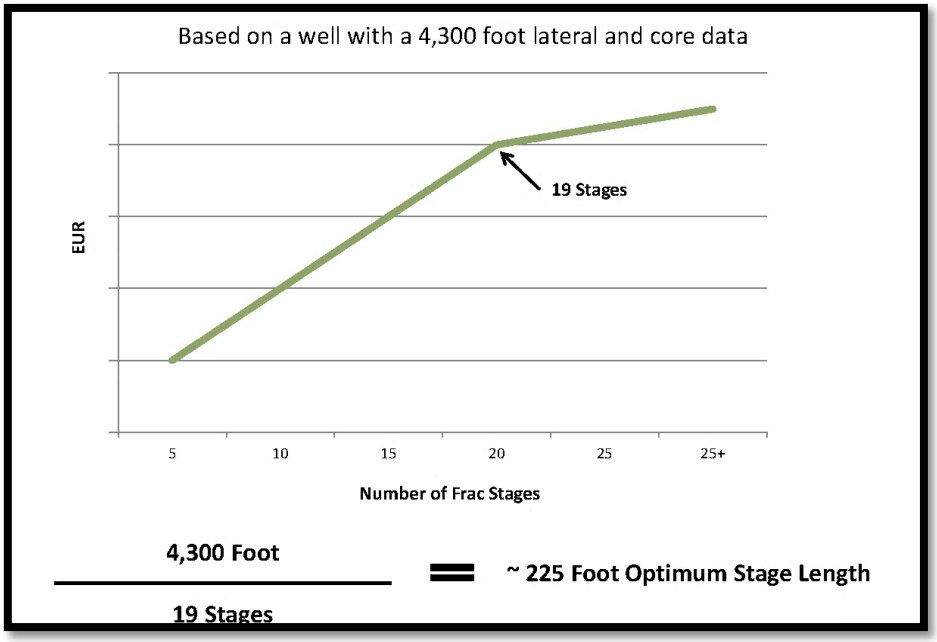
(Krohn, 2106)

From the figures above it seems that this pipeline bottleneck is starting to disappear with increasing infrastructure and processing units to be built.

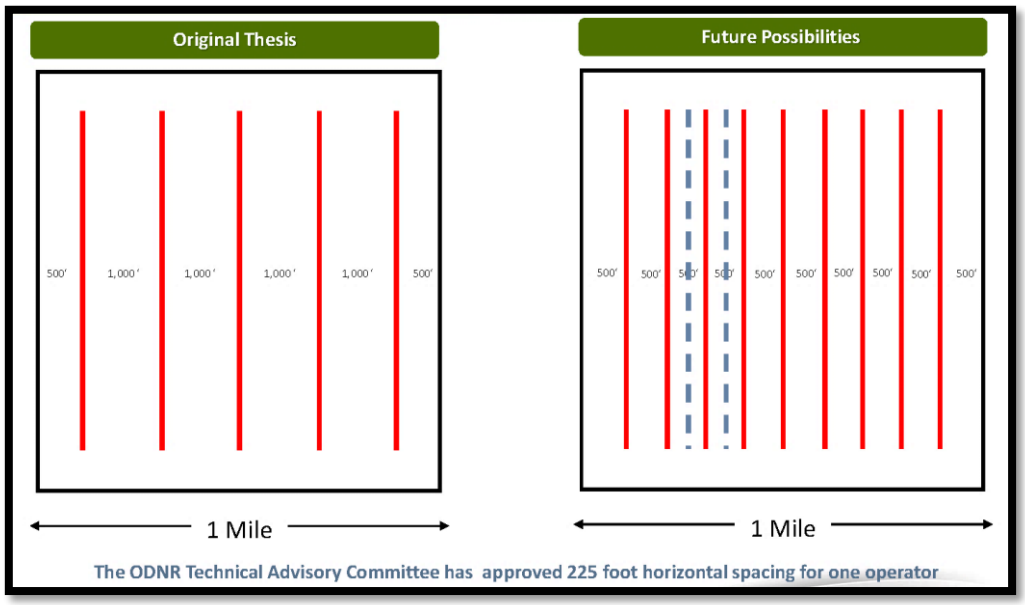
Completion Techniques:

Average well cost range from 8 to 30 million dollars per well. The basic completion concept is to drill with long laterals, have short stages, and shut in the well for a determined resting period.

A new technique used to test the possible productivity of a new well is to set a permanent plug isolating the final stage or the stage closest to the well head while letting the other stages rest, usually three or more months (EID, 10/10/2012). Gulfport Energy found a 225 foot optimum stage length and is now thinking about 250 feet between laterals.



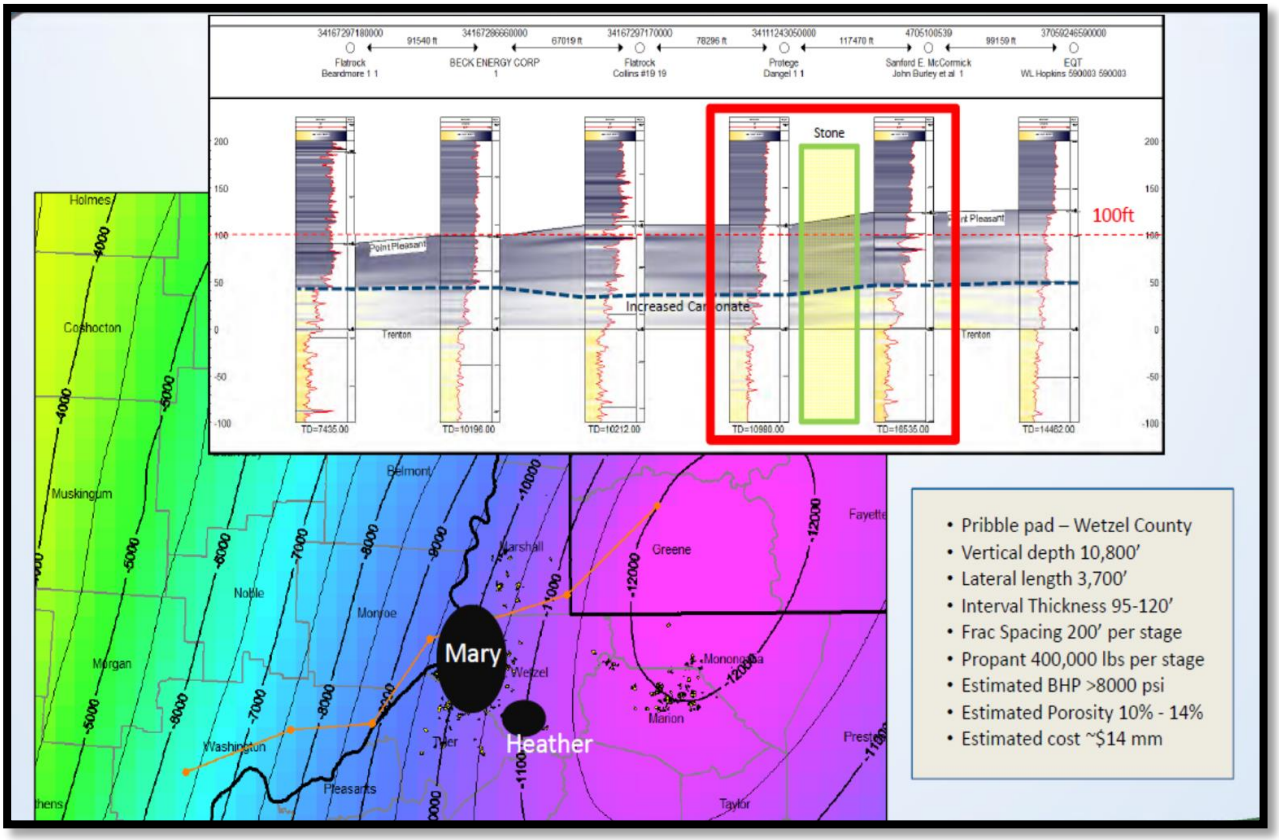
(Gulfport Energy Inc DUG East 11-14-2012)



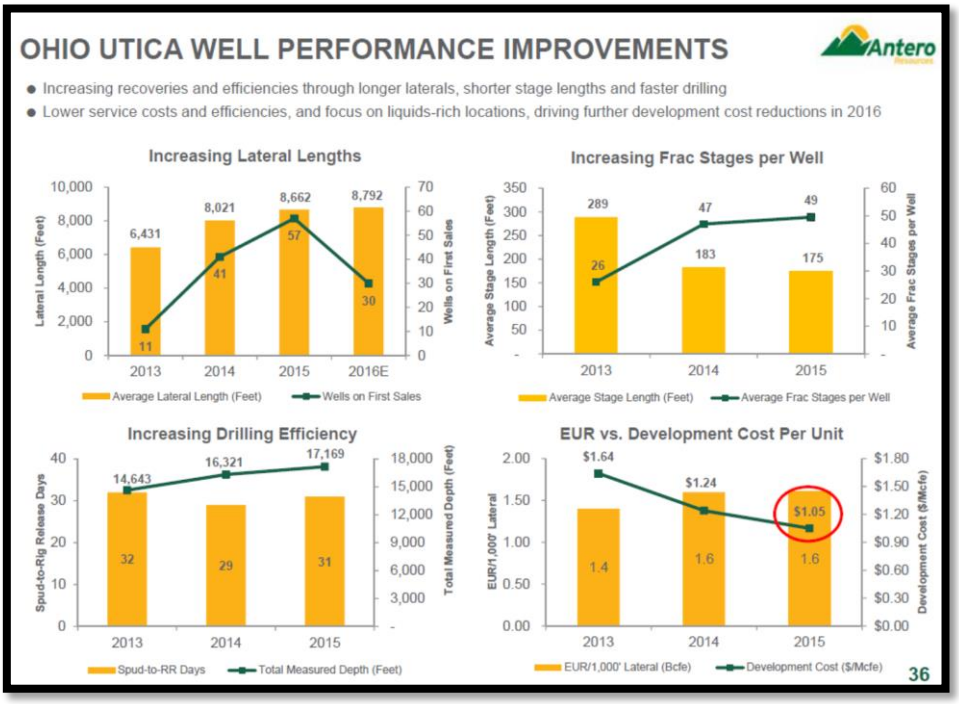
Lateral spacing consideration of Gulfport Energy Inc

(Gulfport Energy Inc DUG East 11-14-2012)

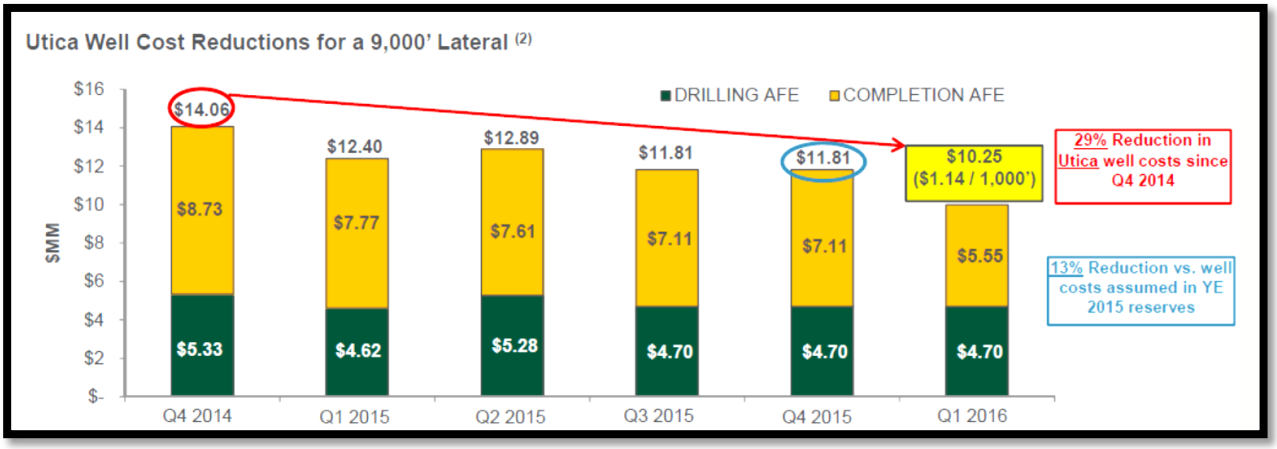
Estimated Cost and Completion Parameters for a WV well



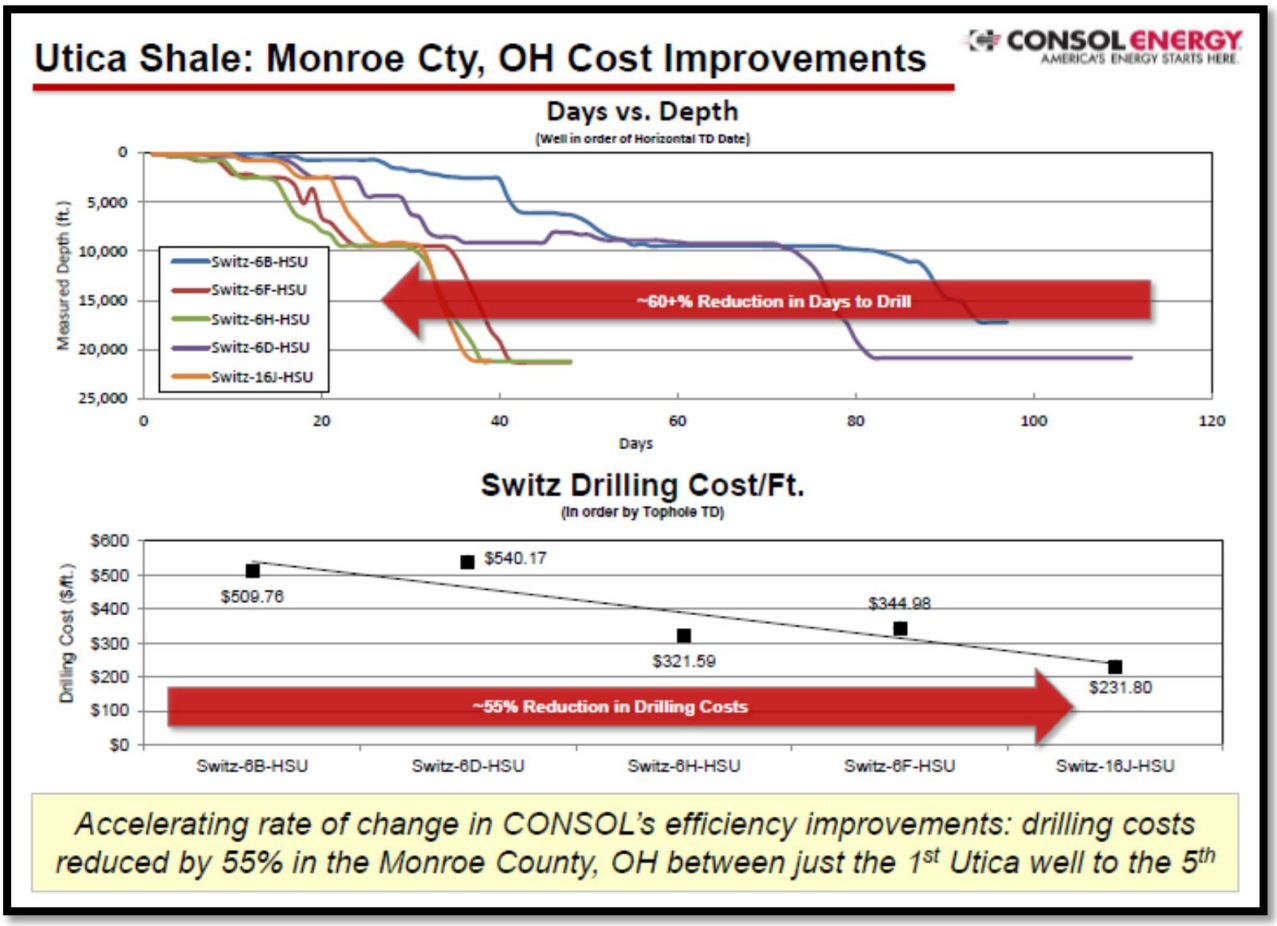
(Stone Energy, 2014)



(Antero Presentation, 2016)



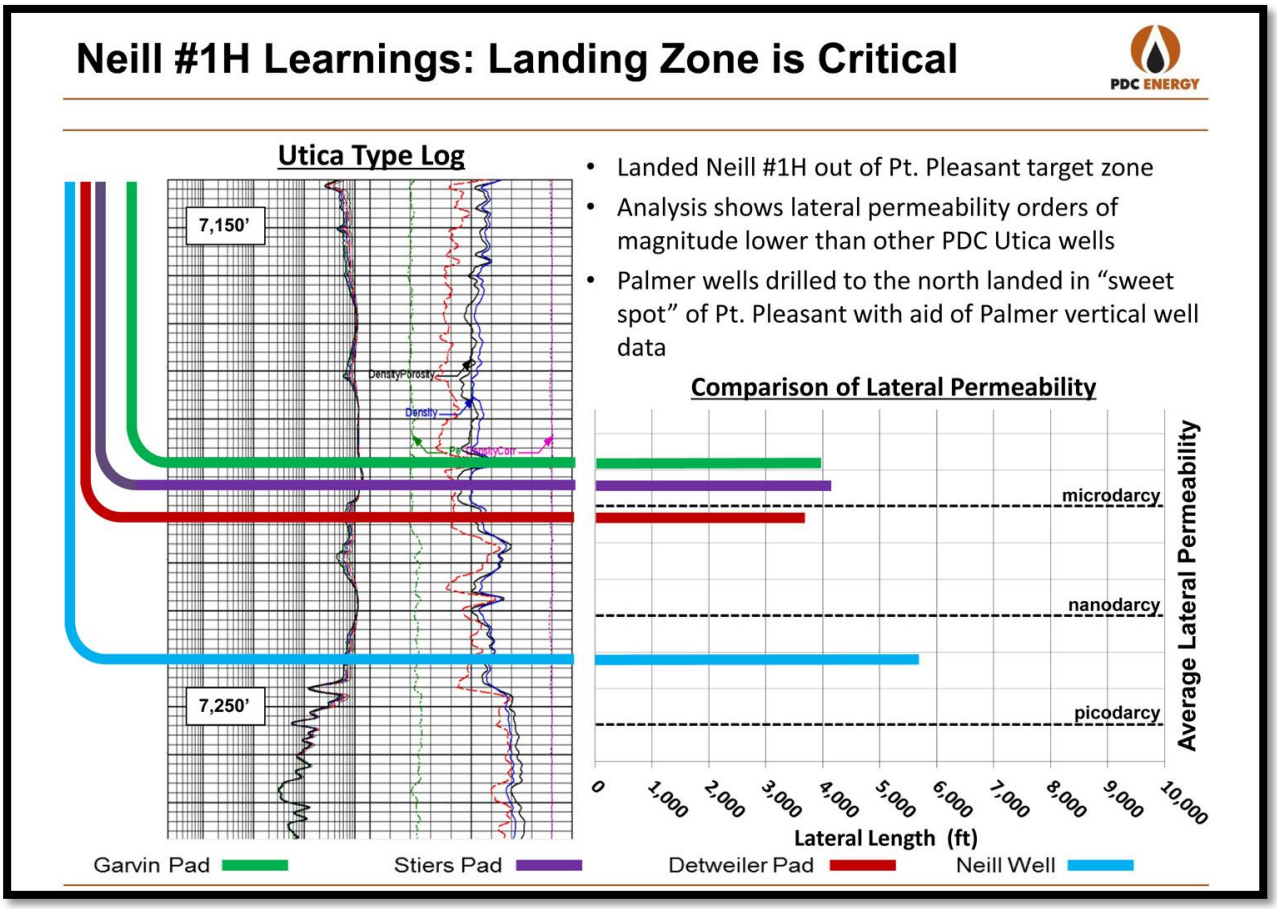
(Antero Presentation, 2016)



(Consol Energy Presentation, 2016)

From the charts above, companies are reducing days to drill which reduces well completion costs. Consol Energy spent 27 million to drill the Gaut 4IH, including drilling, completion and laid pipe. Consol Energy predicts cost for an average 13,000 foot well TVD in PA to 12 million a well (Pickett, 2015). Consol is also trying to reduce costs by experimenting with different propants ceramic, resin coated and white sands (Pickett, 2015).

The Purple Hayes 1H well was drilled and completed under the budgeted 15.8 million. The Purple Hayes 1H used a frac design that consisted of 100 percent slickwater and white sand. Slickwater appears to create a more complex fracture system closer to the wellbore. Eclipse Resources was able to drill the entire lateral length with a single bit on a rotary steerable assembly. Eclipse Resources also reports that only one of the 125 stages failed to effectively put away 1,400 pounds pumped per foot per lateral. The stages were evenly spaced. Eclipse Resource Research finds 100-150 feet spacing in condensate wells and 220 feet in dry gas wells were optimal. The Purple Hayes 1H also is heavily chocked to manage condensate decline (Beim, 2016).



(PDC presentation, 2015)

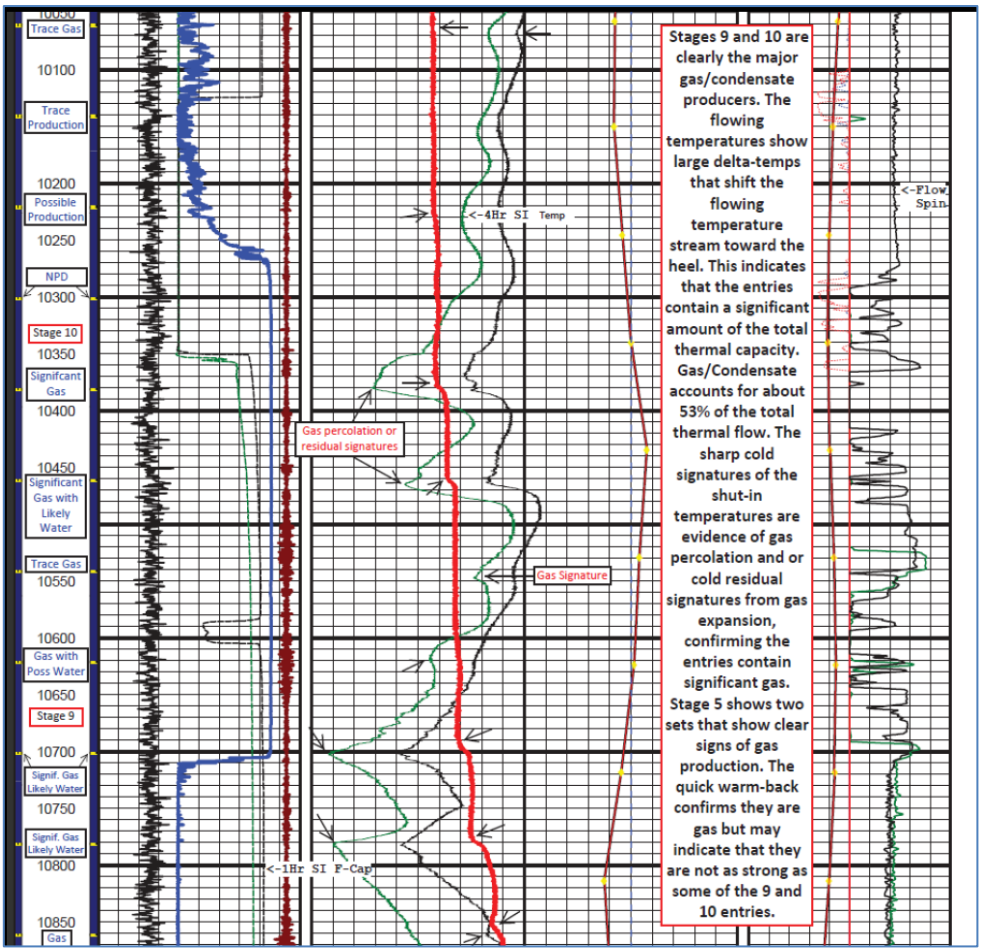
From the Gulfport cross section above which showed uniform stratigraphy and petrophysical properties landing in the sweet spot could determine if a well is successful. The Landing Zone figure above demonstrates also that steering a well is important because differences in amplitude will result in variable economics that could be a result of different lateral permeability.

Table 8-3. Legacy porosity and permeability data for selected Ohio wells.

API No.	Well Identification	No. Samples	He φ (%)	Hg φ (%)	Hg k (md)
34101201960000	Prudential 1A	7		0.03-1.31	1.0E-7 to 1.0E-6
34157253340000	OGS CO2-1	2		0.64-1.25	1.2E-6 to 5.1E-6
34139206780000	Copper Shelby	3		0.85-3.34	2.3E-6 to 1.93E-3
34133208670000	K Vasbinder	4		0.11-0.89	1.0E-7 to 2.9E-6
34151254750000	PSR1	3		0.29-1.01	4.0E-7 to 3.1E-6
34167286660000	Strass 1	2		0.37-0.55	1.0E-7 to 6.0E-7
34169248500000	Davis View 1	2		0.26-1.08	3.0E-7 to 3.5E-6
34005241600000	Eichelberger	25	2.2-8.2	0.03-1.31	1.0E-7 to 1.0E-6

Porosity – φ, measured in percent (%) using He (helium pycnometry) or Hg (mercury injection) techniques
Permeability – k, measured in md

(Patchen, D.G. and Carter, K.M., 2015)

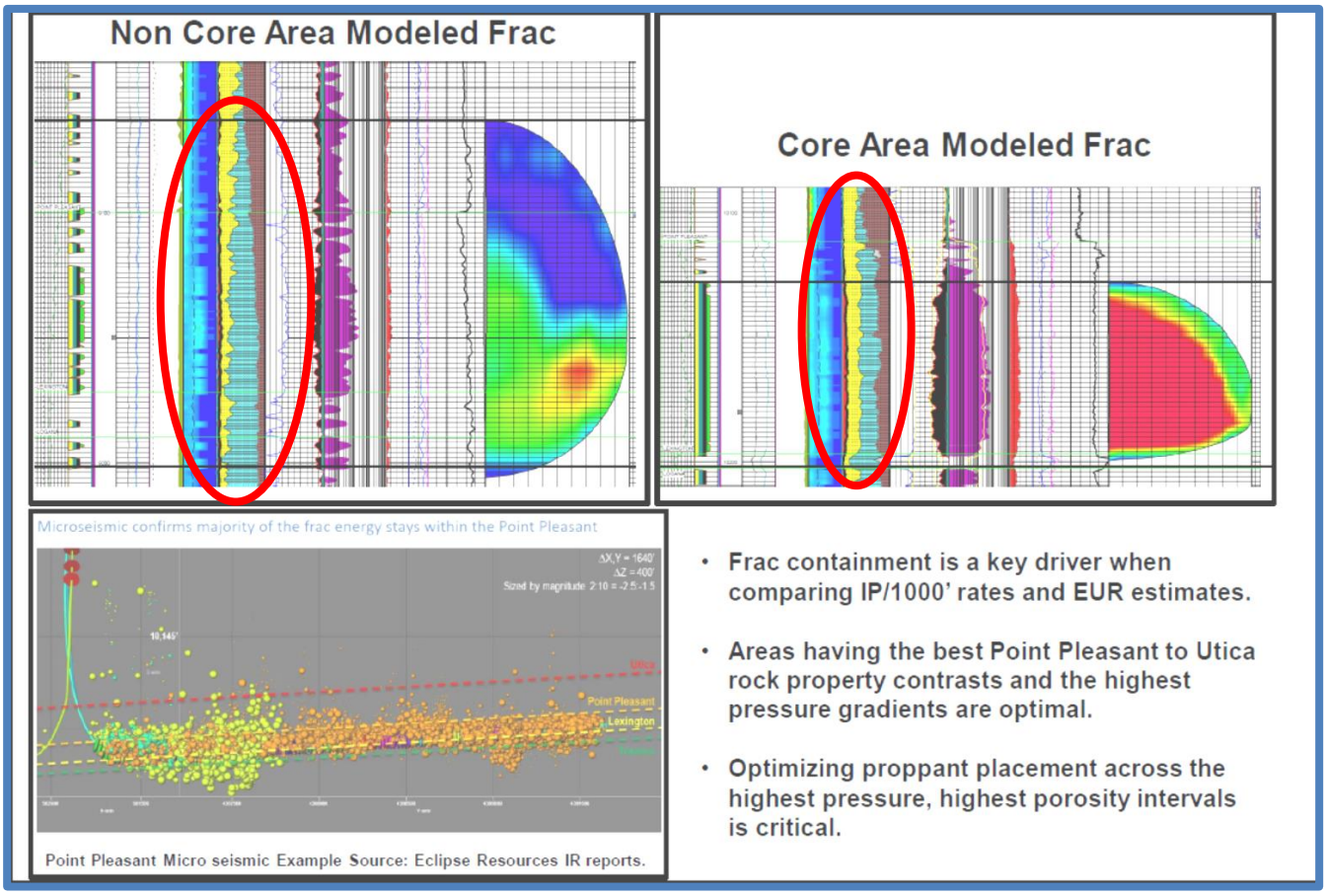


Production Log from a Gulfport Energy well (Gulfport Energy Inc DUG East 11-14-2012)

PDC Energy has noted that flowback management of Utica/Point Pleasant wells is critical to the success of this unconventional resource play (PDC presentation, 2014). Preliminary data indicate that applying back pressure during initial flowback can significantly increase reserves and

economics of Utica/Point Pleasant wells. Their initial performance results demonstrated longer-term productivity and a lower decline rate in wells simply by decreasing the choke size. PDC Energy also noticed differences in permeability depending on where they landed their laterals, see figure above.

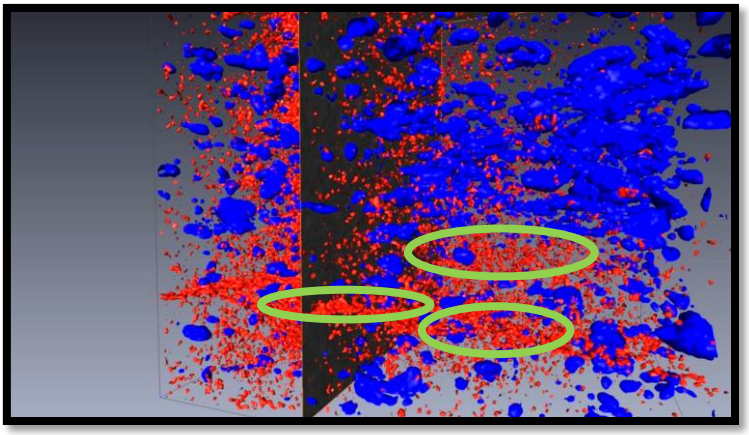
With more development of the Utica/Point Pleasant play, the figure below becomes more interesting. What is different in the high pressure gradient area as opposed to the area in the eastern Ohio? Three things stand out, the density logs are decreasing as you go east and there seems to be a subtle increase in the clay content and a subtle decrease in calcite to the east, and a subtle increase in quartz. TOC increases as does porosity as you go east. See the figure below from Range Resources showing the differences in the two areas. In the core area the bulk mineralogy is different than the non-core area.



(Range Resources, 2015)

A conclusion from a paper by Swift, et al 2014 which looked at nano to microscale pore characterization of the Utica Shale found that mudstones with abundant clasts and clay reduces anisotropy more at the nanometer scale of clay folia than at the microscale of clasts themselves. Swift, et al 2014, conclude that wrapping of clay folia around clasts of every size may be expected to mediate local diffusivity and permeability, and potentially enhance the ability of fractures to propagate in directions other than horizontal. The figure below shows micro CT imagery of a Utica core showing the blue higher density minerals such as calcite, in the form of fossils and the red being voids, organics and low density minerals. The green highlighted areas would indicate where porosity may be and areas of permeability. The blue areas would indicate containment.

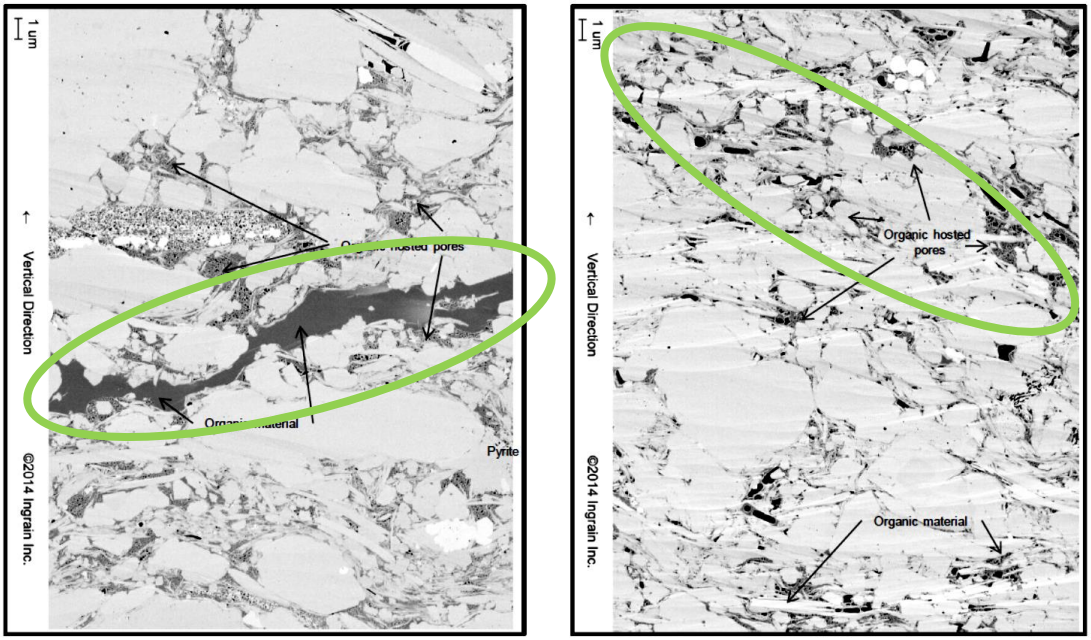
Micro CT Image of a Utica Core



(Swift, et al, 2014)

TOC and Porosity:

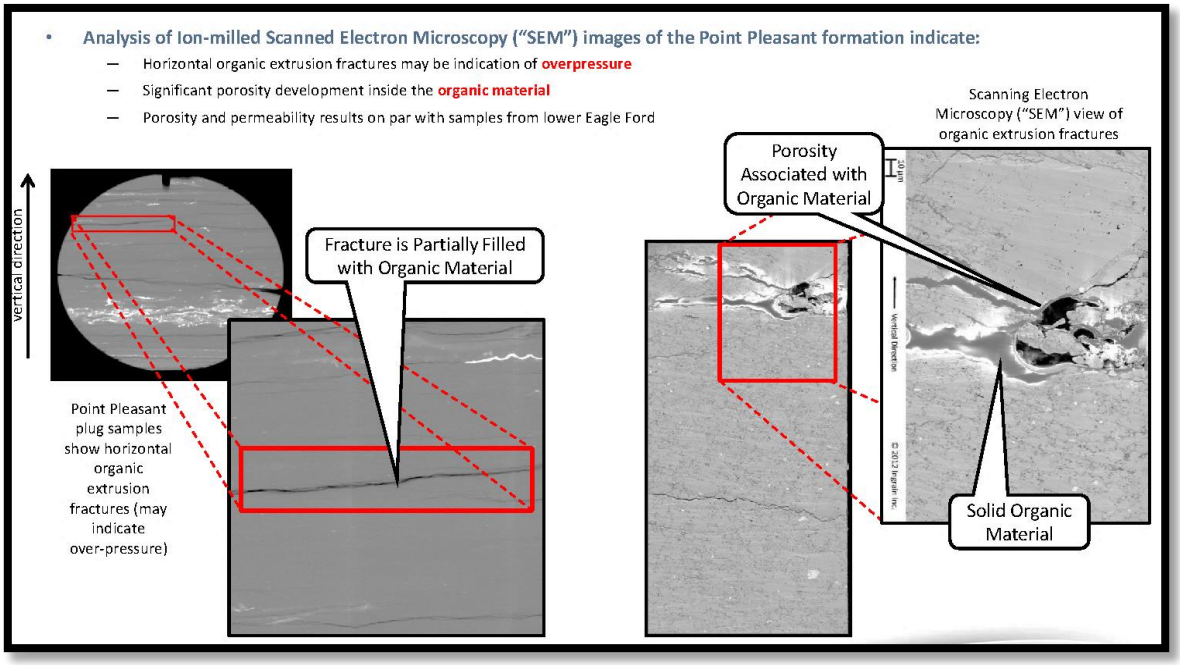
Claysville 11H Point Pleasant Pore Systems



FIB SEM examples from lateral target interval. Note TOC content and well developed pore network.

(Range Resources, 2015)

Comparison of ion milled SEM images from the high IP and Pressure gradient area and the Point Pleasant outside that area. The left image would show increased permeability in areas of organic matter and the right side would demonstrate area of porosity and lower permeability with a pore network that could create more permeability when the organic matter is fraced.



(Gulfport Energy Inc DUG East 11-14-2012)

As SEM imaging has shown that matrix porosity is minor to non-existent in these rocks, it is the organic matter pores that are the major contributor to hydrocarbon production in the Utica/Point Pleasant play (Smith, 2015). Below are two examples where organic matter can be tied to hydrocarbon production and porosity.

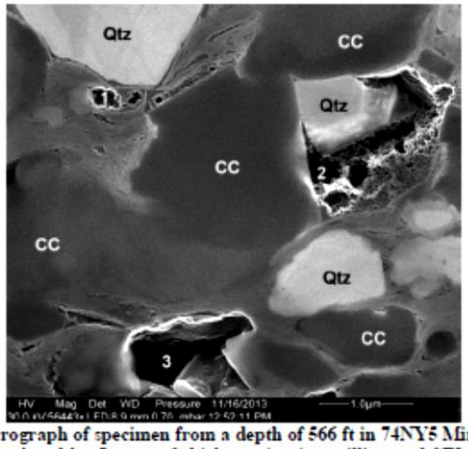


Figure 8-5. Photomicrograph of specimen from a depth of 566 ft in 74NY5 Mineral Core, Herkimer County, New York, analyzed by Juergen Schieber using ion milling and SEM imaging techniques. Qtz=quartz, CC=calcite. Area 1 shows development of large bubble pores in organic matter; Area 2 shows development of bubble pores into deep, connected channels/tubes; Area 3 shows a completely open framework pore defined by calcite grains. One could envision progressive development of organic matter pores from foam to bubbles to tubes in the organic matter, and finally completely emptying of framework pore spaces due to out-migration of liquid hydrocarbons.

(Patchen, D.G. and Carter, K.M., 2015)

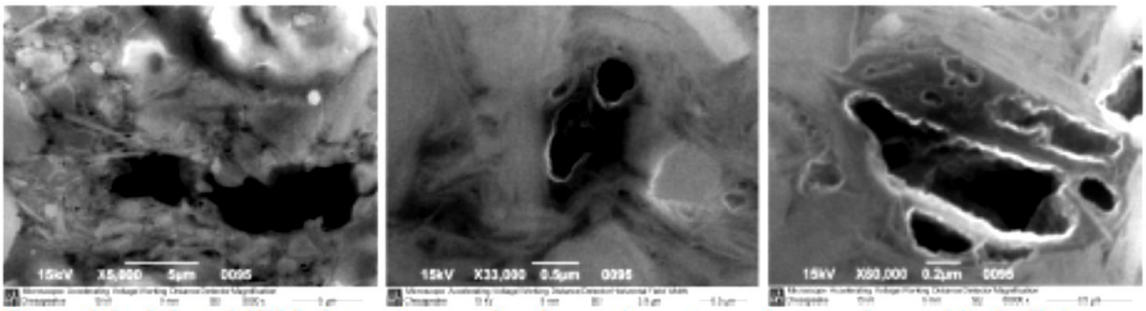
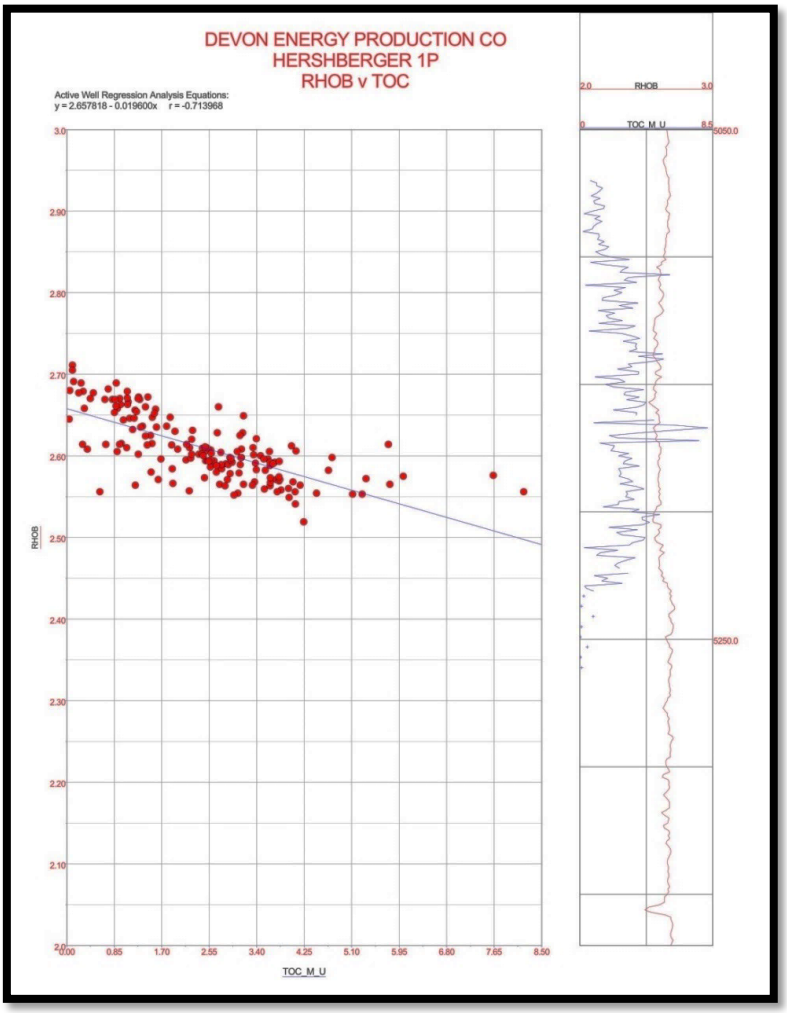


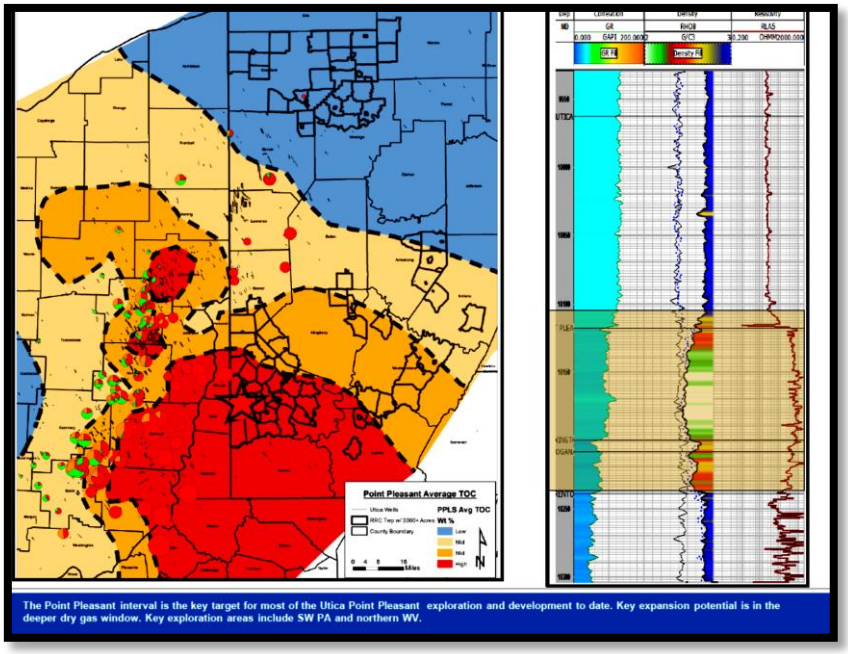
Figure 8-1. Selected SEM photomicrographs of organic matter and pores observed in the Point Pleasant Formation of the Fred Barth No. 3 well, Coshocton County, Ohio.

(Patchen, D.G. and Carter, K.M., 2015)

In the figure below, one of the five Utica cores taken by Devon Energy in Ohio we see a strong correlation between RHOB and TOC just as we saw in the Gastar's Exploration's cross section of increased pressure gradients and volumes.

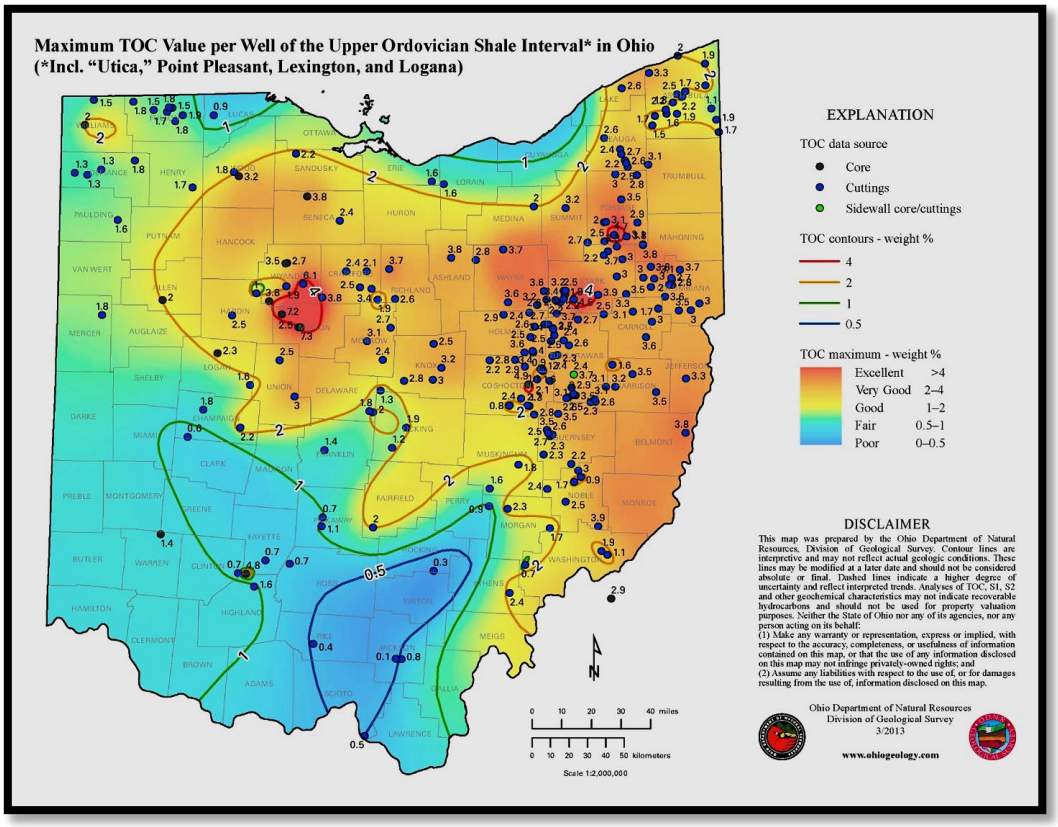


(Erenpreiss, 2015)



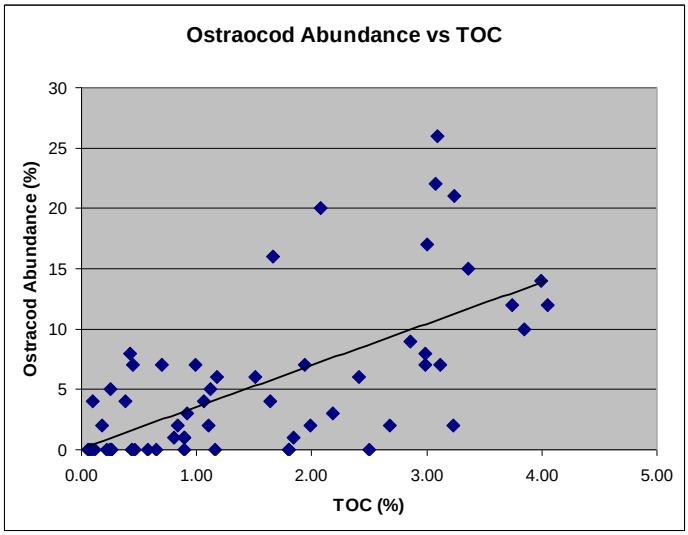
(Range Resources, 2015)

This figure above show an increase in TOC to the southeast and it tends to agree with a revised Ohio Geological Survey Map below.



(ODNR, March 2013)

In May of 2012, a TOC (Total Organic Content) map generated by the Ohio Geological Survey caused a fall out between the State Geologist and critics from southeastern counties of Ohio. The main criticism of the map was the limited amount data points in the southeastern part of the state which may have caused limited interest and lower lease and bonus prices offered to landowners.



(Smith, 2015b)

One last word about TOC, Smith 2015, from his five core study found a correlation between ostracod abundance and TOC. This line of evidence would support a shallow depositional environment

PRODUCTION:

Ohio Production Data	Utica-Point Pleasant Production			Total Production		
Year	Oil (Barrels)	Gas (Mcf)	No. of Wells	Oil (Barrels)	Gas (Mcf)	No. of Wells
2011	46,326 (1%)	2,561,524 (3.5%)	9	4,853,000	73,290,000	50,192
2012	635,874 (13%)	12,831,292 (15%)	87	4,974,000	86,770,000	~50,000
2013	3,643,141 (45.5%)	99,532,124 (59.4%)	360	8,006,000	167,293,000	~ 50,000
2014	10,847,211 (70%)	445,466,231 (85%)	786	15,300,000	518,000,000	~50,000
2015	21,983,959 (99%)	953,863,990 (114.1%)	1230			
Cumulative Production	**37,156,511**	**1,514,225,161**	**1230**			

(Modified from Riley and Fakhari, 2015)

Production has increased steadily from 2011, how decreased drilling and greater producing wells will affect the numbers above, only time will tell.

ISSUES: The Ohio Division of Natural Resources confirmed 11 low magnitude earthquakes that occurred near Hilcorp Energy Corp's well pad operations in Poland Township Ohio. The series of earthquakes were recorded by both the USGS and Columbia University's Lamont-Doherty Earth Observatory. The USGS confirmed five earthquakes ranging from 2.1 - 3.0 magnitude and Columbia University's Lamont-Doherty Earth Observatory registered six lower magnitude shocks in other places in the region (McParland, T., 2014)

The first quake occurred at a depth of 1.2 miles and the second quake was recorded at a depth of 3miles (Obrien, D., 2014). The Precambrian basement is at 9000 feet and the vertical depth of the Hilcorp Energy well in the area is at a depth of 7900 feet.

These earthquakes are have brought attention to whether fracking causes these earthquakes or are they naturally occurring. Ohio records show that the area between 1950 and 2009 averaged 2 earthquakes annually with magnitude 2.0 or greater. Between 2010 and 2014 the average rose to nine (Drabold, W., 2014). The Ohio Division of Natural Resources has halted operations and have been petitioned by local residences to set up a seismic network in the area to monitor operations. The area is close to the Youngstown where an injection well was determined to cause earthquakes in 2011.

Governor Kasich has proposed a flat tax of 2.75% on producer's gross receipts (Provance, J., 2014).

SITES:

http://www.wvgs.wvnet.edu/Utica This website will lead you to the Utica Shale Appalachian Basin Exploration Consortium's three year study on the Utica Shale in five States pertinent to the play. This website has three parts DATA, INTERACTIVE MAP, and Downloads Section that contain the following data outlined below.

The "Data" section of the website contains all data collected, processed and analyzed during the course of the project's research. Website users may access these data via a well document file search which links to the project database. This document search allows users to create a custom search of the project database. A search may utilize one or more of the following criteria:

☐☐API number

☐☐File category

☐☐State

☐☐County

Results of the data search may also be exported to Excel, where the data are able to be further sorted. Hyperlinks to the individual files are embedded in the Excel file, which allows users to link back to the project webpage to retrieve the data without performing a duplicate search.

The Utica Shale Play Book Study's "Interactive Map" application utilizes ESRI ArcGIS Server technology and is designed to allow users to visualize geologic data in spatial context (Figure 1-1). Data include the following:

□□Wells

o With Supplemental Data :

□□Digitized Well Logs

□□Scanned Well Logs

□□Source Rock Analyses

□□Total Organic Carbon (TOC) Data

□□Core Photographs

□□Scanning Electron Microscopy (SEM) Images-Data

□□Thin Section Images

□□Thin Section Descriptions

□□All Wells with Data (i.e. a file on the FTP server)

o With Formation Tops2:

□□Upper Ordovician

□□Kope

□□Utica

□□Point Pleasant

□□Lexington/Trenton (includes Logana and Curdsville members)

□□Black River

□□Cross-Sections3

o Lines

o Wells

□□Maps

o Faults

□□Play Areas

o Utica

o Ordovician Outcrops

The "Downloads section "contains the Playbook, Presentations, Shapefiles, Petra Utica File, Well Files and a Utilize Mapping Services Section ***(Patchen, D.G. and Carter, K.M., 2015)***

http://geosurvey.ohiodnr.gov/major-topics/interactive-maps 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://oilandgas.ohiodnr.gov/shale#SHALE This is the website to get weekly activity and yearly production information in Ohio.

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OKLAHOMA SHALE GAS/TIGHT OIL PLAYS, U.S.A.

Brian Cardott (Oklahoma Geological Survey)

Figure 1 illustrates 4,624 Oklahoma shale gas and tight oil well completions (1939–2016) on a geologic provinces map of Oklahoma. The Oklahoma Geological Survey has a database of all Oklahoma shale gas and tight oil well completions (http://www.ou.edu/content/ogs/research/energy/oil-gas.html). The database of 4,624 well completions from 1939 to February 2017 contains the following shale formations (in alphabetical order) and number of completions: Arkansas Novaculite (3), Atoka Group shale (1), Barnett Shale (2), Caney Shale or Caney Shale/Woodford Shale (125), Excello Shale/Pennsylvanian shale (2), Goddard Shale (lower Springer shale)(61), Sylvan Shale or Sylvan Shale/Woodford Shale (21), and Woodford Shale (4,409). Shale wells commingled with non-shale lithologies are not included. Exceptions include 20 Sycamore Limestone/ Woodford Shale, 12 Mississippian/Woodford Shale, and 3 Hunton Group carbonate/Woodford Shale horizontal completions where non-Woodford perforations were minimal. The database was originally restricted to shale-gas wells. Tight-oil wells have been added since 2005.

The clay-rich Mississippian Caney Shale (age equivalent to the Barnett Shale and Fayetteville Shale) well completions in 2001–2010 in the Arkoma Basin in eastern Oklahoma resulted in relatively poor gas wells while recent drilling (2012–present) in the Caney Shale in southern Oklahoma have been more successful (initial potential (IP) gas rates of 57–2,801 thousand cubic feet (Mcf) and IP oil/condensate (37–54° API gravity) rates of 11–620 barrels of oil per day (bopd)).

The newest shale resource play in Oklahoma (2013–present) is the Mississippian-age lower Springer shale (Goddard Shale) in the South Central Oklahoma Oil Province ("SCOOP") in the southeastern Anadarko Basin (Figure 1). Of 58 horizontal Springer/Goddard shale well completions in Carter, Garvin, Grady, and Stephens counties in 2013–2016, IP gas rates were 4–4,311 Mcf and IP oil/condensate rates (41–54° API gravity) were 10–2,785 bopd at vertical depths of 11,332–14,618 feet. The Springer/Goddard shale play is held by production so operators in the play in 2015 indicated no new drilling is planned for the year thereby holding on for higher oil prices (Toon, 2015b). Summaries of the play are in Bates (2015), Darbonne (2015), Nash (2014), Redden (2015), and Toon (2015a).

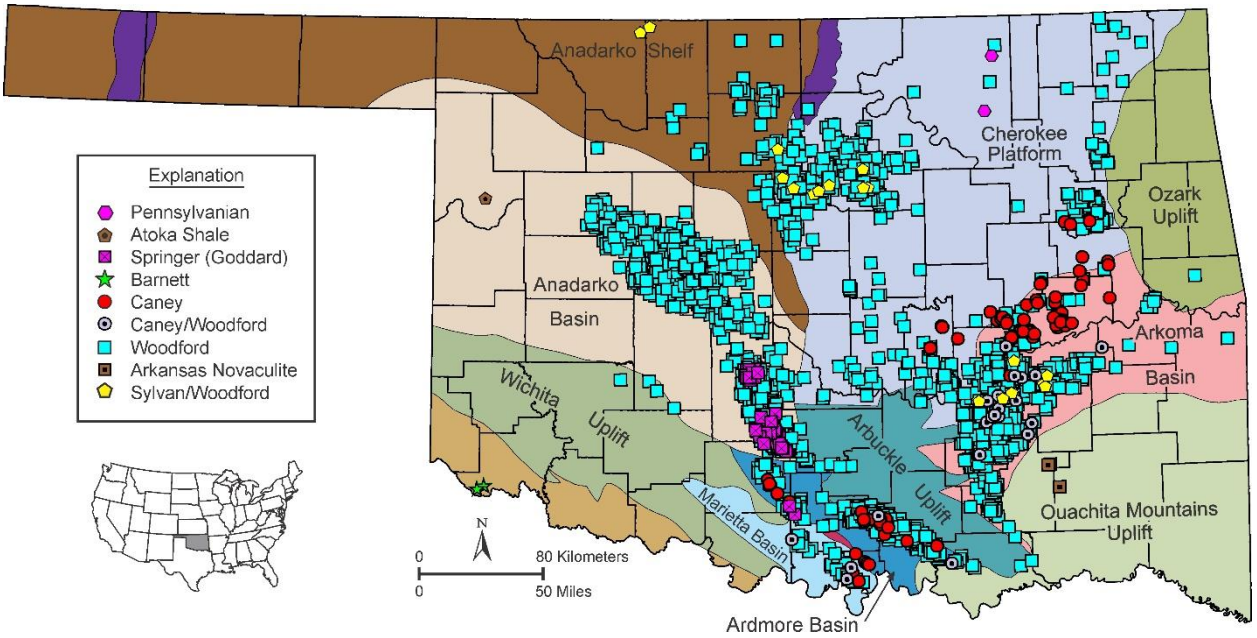

Figure 1. Map showing Oklahoma shale gas and tight oil well completions (1939–2016) on a geologic provinces map of Oklahoma (modified from Northcutt and Campbell, 1998).

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" for western Canadian County or "SCOOP" plays and western Arkoma Basin) and oil (northern Ardmore Basin, "Cana", "SCOOP", and north-central Oklahoma) areas. Of the 4,389 Woodford-only well completions from 2004–2016, 91% (3,990 wells) are horizontal/directional wells and 9% (399 wells) are vertical wells; 1,204 Woodford Shale wells are classified as oil wells based on a gas-to-oil ratio <17,000: 1. Total vertical depths range from 368 ft (Mayes Co.) to 19,547 ft (Grady Co.). IP gas rates range from a trace to 18.6 million cubic feet per day. IP oil/condensate rates range from a trace to 2,505 bopd (Garvin County). Reported oil gravities range from 21 to 67 API degrees.

The annual peak of 610 Woodford Shale well completions occurred in 2014 (Figure 2). Following the drop in natural gas prices in 2008, the emphasis in the Woodford Shale plays has been for oil- and condensate-producing wells. The recent drop in oil prices has resulted in a significant decline in Woodford Shale completions (265 in 2016). Figure 3, showing Woodford Shale wells from 2004–2016, illustrates the expansion of the Woodford Shale condensate play in the Anadarko Basin which began in "Cana" in 2007 and "SCOOP" in 2012. There is an expansion of the play in north-central Oklahoma where the Woodford Shale is in the lower half of the oil window.

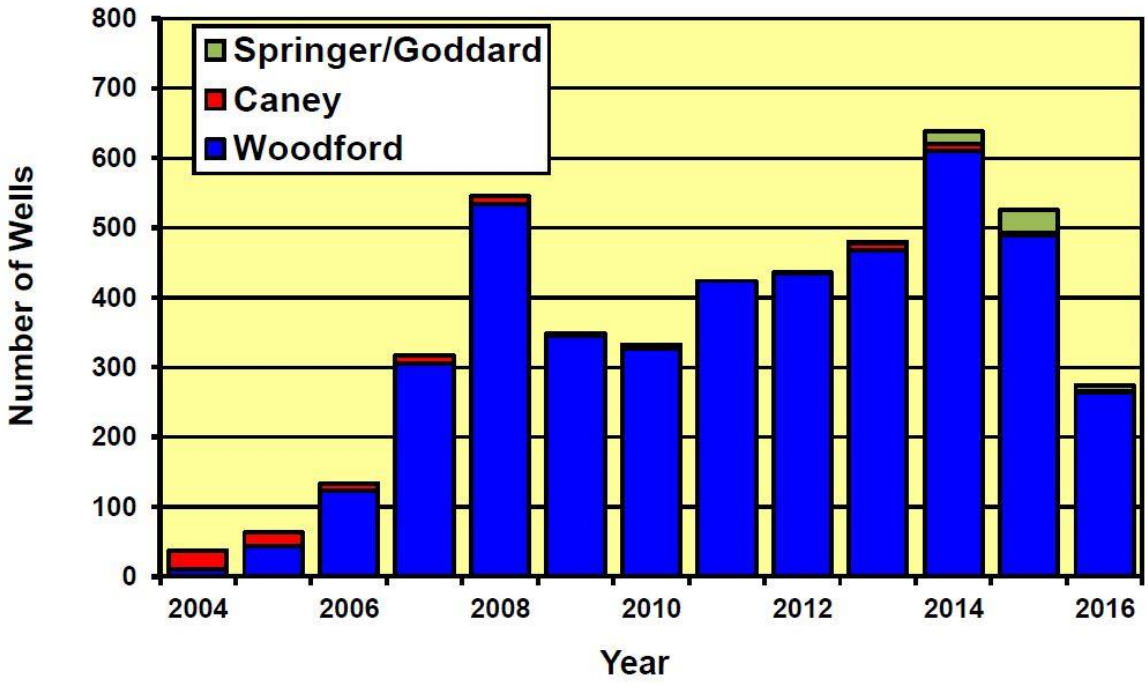

Figure 2. Histogram showing numbers of Woodford Shale, Caney Shale, and Springer/Goddard shale well completions, 2004–2016.

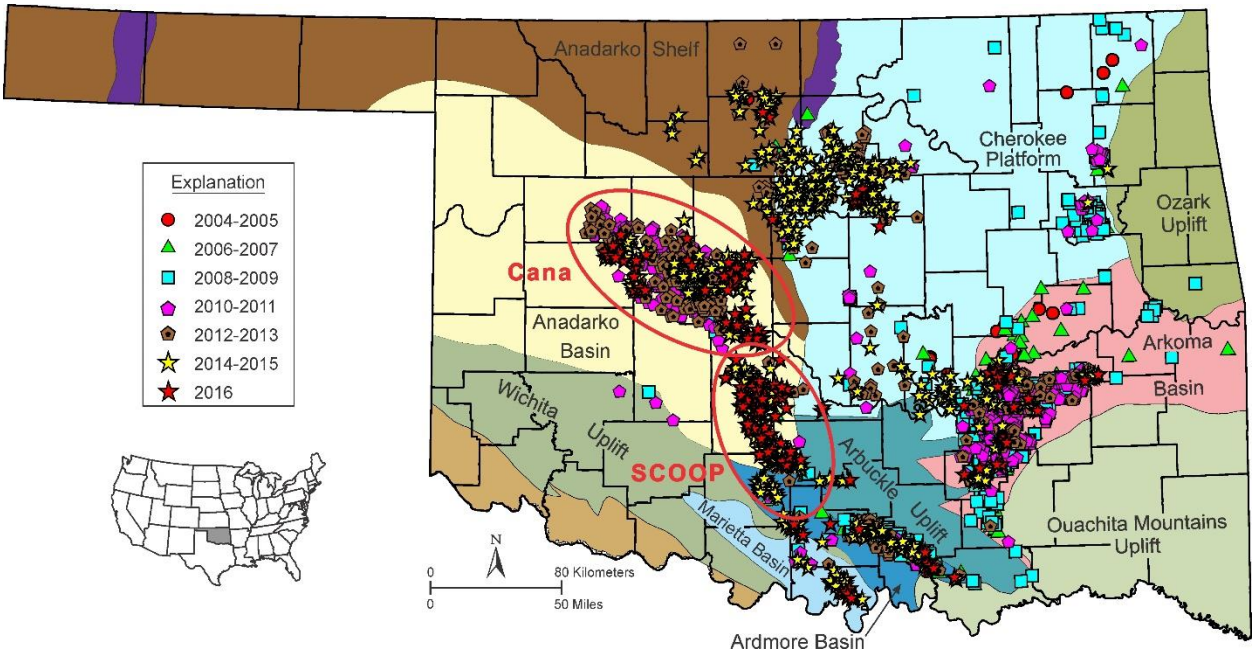

Figure 3. Map showing Woodford Shale-only gas and oil well completions (2004-2016) on a geologic provinces map of Oklahoma.

Of 27 operators active in Oklahoma shale resource plays (not just the Woodford) during 2016, the top nine operators (for number of wells drilled during 2016) are:

(1) Continental Resources (56)
(2) Petroquest Energy (42)
(3) XTO Energy (32)
(4) Newfield Exploration Mid-Continent Inc. (27)
(5) Citizen Energy II (19)
(6) Vitruvian II Woodford (16)
(7) Cimarex Energy (15)
(8) Devon Energy (12)
(9) BP America Production Company (11)

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STATUS OF INTERNATIONAL ACTIVITIES

CANADIAN SHALE GAS AND LIQUIDS

Jock McCracken (Egret Consulting, Vancouver)

Even though Canada has an abundance of conventional oil and natural gas, unconventional gas, liquids and oil plays dominate the headlines. Most of these shale opportunities lie within the Western Canadian Sedimentary Basin (WCSB) which is a vast sedimentary basin underlying 1,400,000 square km (540,000 sq. mi) of Western Canada including southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia, southeast corner of the Yukon and the southwest corner of the Northwest Territories. It consists of a massive wedge of sedimentary rock extending from the Rocky Mountains in the west to the Canadian Shield in the east. This wedge is about 6 km (3.7 mi) thick under the Rocky Mountains, but thins to zero at its eastern margins. The WCSB contains one of the world's largest reserves of petroleum and natural gas and supplies much of the North American market, producing about 658,000 BOPD and 14 MMCFD gas. Of the provinces and territories within the WCSB, Alberta has most of the oil and gas reserves and almost all of the oil sands.

The first announcement of new discoveries in shale occurred in Canada at the beginning of 2008, seven years ago. Now, about 25% of Canada's natural gas is coming from unconventional which would include tight sands. The state of development for the shale plays range from speculative to exploratory to emerging to developing and under increasing commercial production. Typically, production numbers from government websites are up to one year or more behind. Additional production numbers and exploration statistics for this report are therefore gathered from press releases and presentations from some of the key companies involved with the plays. As a result of the low natural gas operators had been focusing exploration and production into the liquids-rich hydrocarbons. The low oil prices now complicate these plays. The following plays are under development and increasing the production yearly: Horn River and Montney in N.E. B.C., Duvernay and Alberta Bakken in Alberta and the Bakken oil play (tight oil play encased in shale) in Saskatchewan and Manitoba.

There have been other shale that have been disappointments for technical and regulatory reasons. 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 or stop any future exploration and production. The positive announcements out of New Brunswick have

been tempered by recent disappointing results, low gas prices and anti-fracking regulations. To date there is shale exploration activity in 9 provinces of Canada out of the 10 with Prince Edward Island being the exception. One of the three Territories of Canada, the Northwest Territories, is just now seeing the drilling and fracking of their first wells into a possible oil-bearing shale section. The Yukon is evaluating their shale plays as well. The recent drop in oil price has had significant effects on industry production and exploration.

As a further note, there has been significant public concern in the press about hydraulic fracturing in various locations across Canada which is hindering or slowing down exploration and/or production. More discussion about these concerns is occurring in Provinces where there is limited oil and gas exploration and production. Industry and governments are becoming more transparent and self-imposed guidelines are being drawn up. http://www.capp.ca/

Quebec, Nova Scotia, New Brunswick and the Yukon effectively have put hydraulic fracking under partial or full moratorium with Newfoundland and North West Territory under review. Alberta recently updated their regulations. It is hopeful, at the end of this discussion, hydraulic fracturing will be managed such that it will minimize potential risks and allow the public to have a balanced and realistic sense of the costs and benefits.

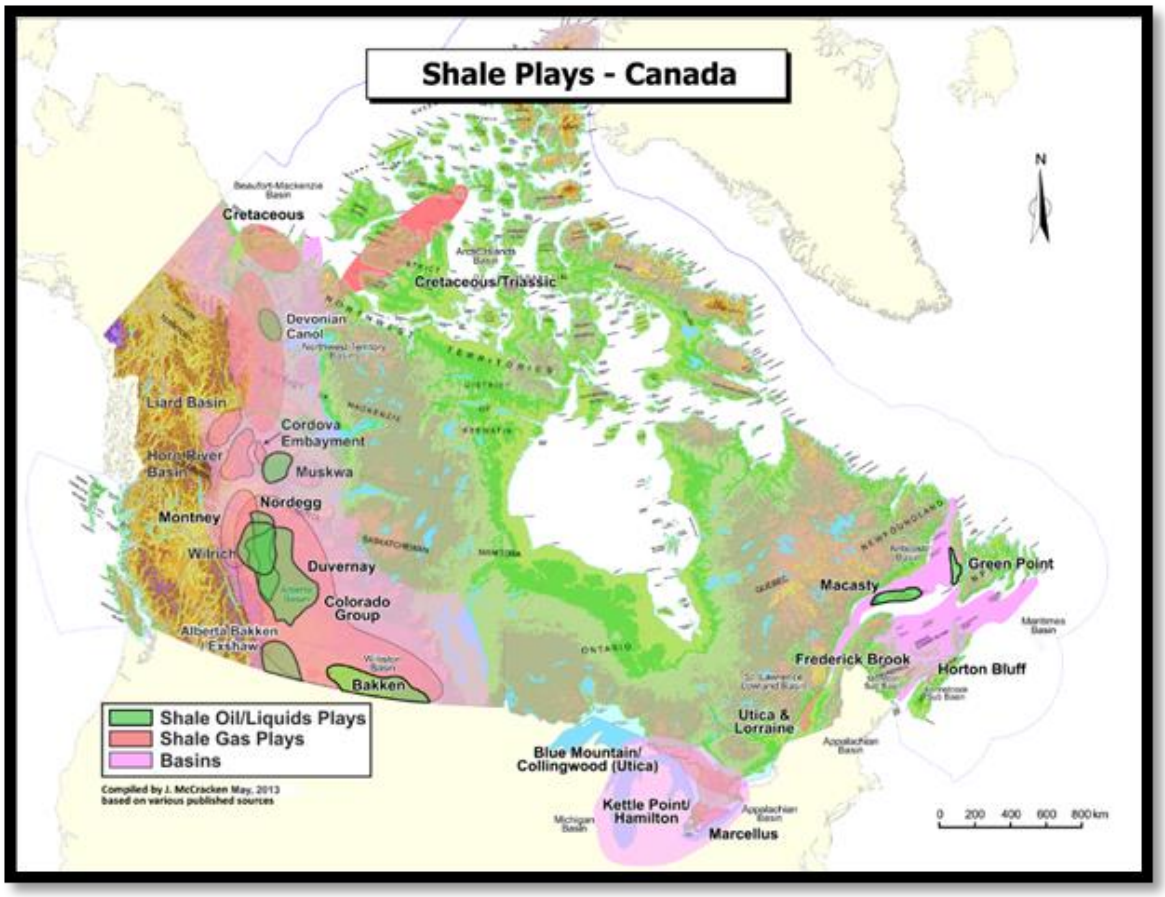
There is a good summary by Natural Resources Canada of shales and tight resources by province. http://www.nrcan.gc.ca/energy/sources/shale-tight-resources/17669

This next table is from the publication by *EIA Technically Recoverable Shale Oil and Shale Gas Resources: Canada, September 2015*. They are reporting that Canada has 162,000 MM BBL of oil/condensate and 2,413.2 TCF of natural gas risked resources in place with 8,840 MM BBL of oil/condensate and 572.9 TCF of natural gas risked resources recoverable. www.eia.gov

Table I-1. Shale Gas and Oil Resources of Canada

Region	Basin / Formation	Risked Resource In-Place		Risked Technically Recoverable Resource	
		Oil/Condensate (Million bbl)	Natural Gas (Tcf)	Oil/Condensate (Million bbl)	Natural Gas (Tcf)
British Columbia / Northwest Territories	Horn River (Muskwa / Otter Park)	-	375.7	-	93.9
	Horn River (Evie / Klua)	-	154.2	-	38.5
	Cordova (Muskwa / Otter Park)	-	81.0	-	20.3
	Liard (Lower Besa River)	-	526.3	-	157.9
	Deep (Doig Phosphate)	-	100.7	-	25.2
	Sub-Total	-	1,237.8	-	335.8
Alberta	Alberta (Banff / Exshaw)	10,500	5.1	320	0.3
	E/W Shale (Duvernay)	66,800	482.6	4,010	113.0
	Deep Basin (Nordegg)	19,800	72.0	790	13.3
	N.W. Alberta (Muskwa)	42,400	141.7	2,120	31.1
	S. Alberta (Colorado)	-	285.6	-	42.8
	Sub-Total	139,500	987.1	7,240	200.5
Saskatchewan / Manitoba	Williston (Bakken)	22,500	16.0	1,600	2.2
Quebec	App. Fold Belt (Utica)	-	155.3	-	31.1
Nova Scotia	Windsor (Horton Bluff)	-	17.0	-	3.4
	Total	162,000	2,413.2	8,840	572.9

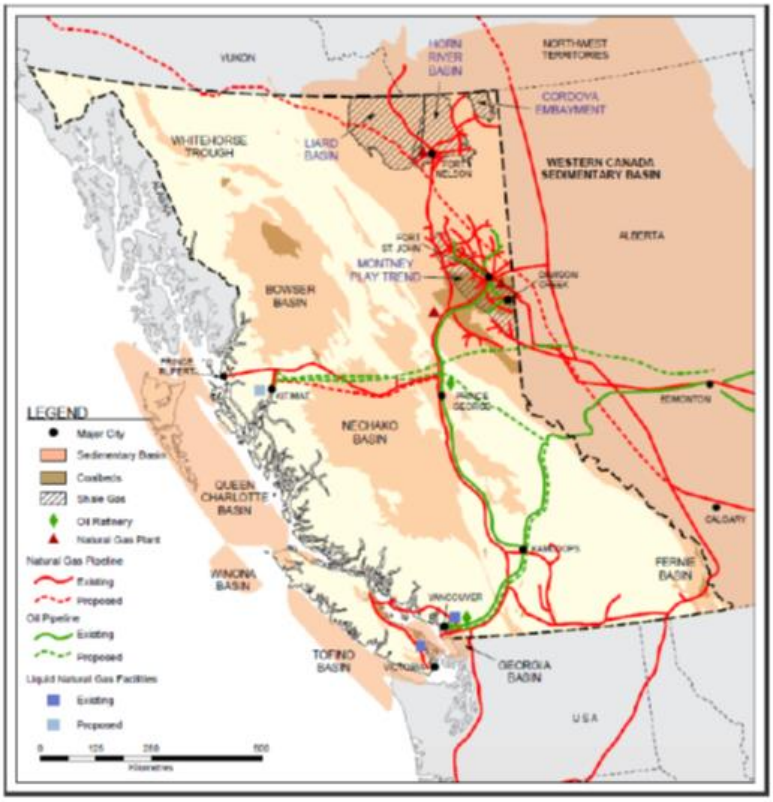
*Less than 0.5 Tcf



NORTHEAST BRITISH COLUMBIA

Northeast British Columbia contains Cretaceous to Devonian aged shale deposits that potentially could contain 2900 TCF of natural gas in place of which over 400 TCF is estimated to be marketable with about 70% being unconventional. The gas production keeps ramping upward with 1.58 TCF (4.4 BCF/D) raw natural gas production in 2013 or 26 % of the total Canadian gas production. Shale gas accounts for about 60% of these volumes. Advances in horizontal drilling and completion techniques have largely contributed to these advances in all the play areas. Industry spending has increased substantially on exploration and development activities over the last 15 years with $7.9 Billion spent in 2008 and $5.2 Billion in 2012. Total oil and as revenue was $1.12 Billion in fiscal 2013. This shale gas interest in all the areas has therefore dominated the sale of petroleum and natural gas (PNG) rights from the province in the last ten years (see chart below). The Montney play is garnering much interest because of its liquids component and now producing at more than 2.26 BCF/D.
http://www2.gov.bc.ca/gov/DownloadAsset?assetId=D2628717CD3D41A5A17E5139F5FCAC53

British Columbia has developed a Natural Gas and Liquefied Natural Gas Strategies considering the immensity of this resource.


YUKON
NORTHWEST TERRITORIES
HORN RIVER BASIN
CORDOVA EMBAYMENT
WHITEHORSE TROUGH
LIARD BASIN
FORT NELSON
WESTERN CANADA SEDIMENTARY BASIN
ALBERTA
FORT ST JOHN
MONTNEY PLAY TREND
DAWSON CREEK
BOWSER BASIN
PRINCE RUPERT
KITIMAT
PRINCE GEORGE
EDMONTON
NECHAKO BASIN
QUEEN CHARLOTTE BASIN
CALGARY
KAMLOOPS
WINONA BASIN
FERNIE BASIN
VANCOUVER
TOFINO BASIN
VICTORIA
GEORGIA BASIN
USA
LEGEND
Major City
Sedimentary Basin
Coalbeds
Shale Gas
Oil Refinery
Natural Gas Plant
Natural Gas Pipeline
Existing
Proposed
Oil Pipeline
Existing
Proposed
Liquid Natural Gas Facilities
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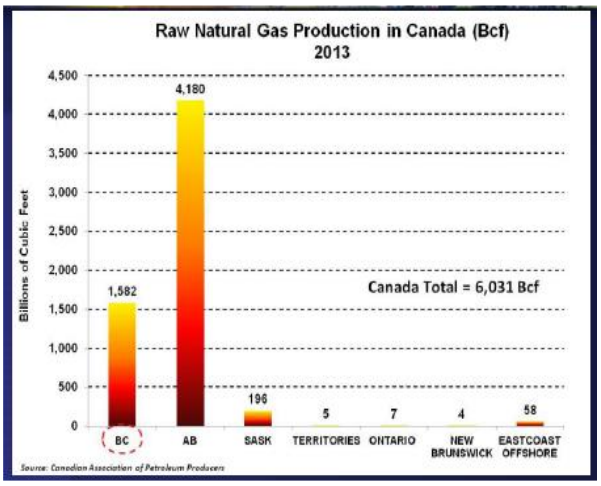
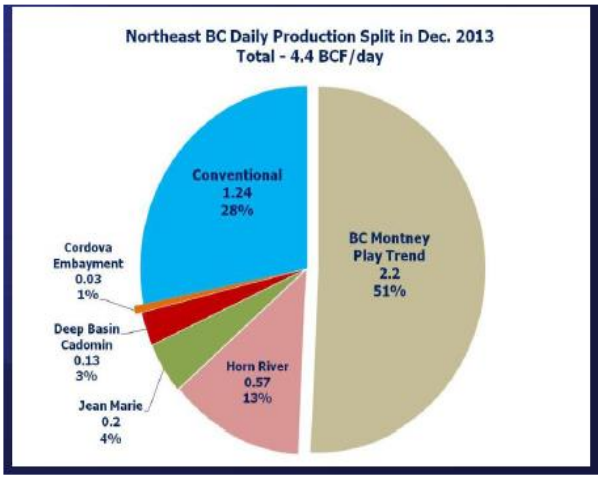

Raw Natural Gas Production in Canada (Bcf)
2013
Billions of Cubic Feet
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
1,582
4,180
196
5
7
4
58
Canada Total = 6,031 Bcf
BC
AB
SASK
TERRITORIES
ONTARIO
NEW BRUNSWICK
EASTCOAST OFFSHORE
Source: Canadian Association of Petroleum Producers


Northeast BC Daily Production Split in Dec. 2013
Total - 4.4 BCF/day
Conventional
1.24
28%
BC Montney
Play Trend
2.2
51%
Cordova
Embayment
0.03
1%
Deep Basin
Cadomin
0.13
3%
Jean Marie
0.2
4%
Horn River
0.57
13%

BRITISH COLUMBIA
Ministry of Natural Gas Development

Resource Potential in BC's Shale Gas Regions

Liard Basin – Devonian
- 9,340 square kilometres
- OGIP – large!
- 2 wells producing (March 2014)
- Daily production – 4.5 MMcf/d
- Cumulative production – 10.1 Bcf

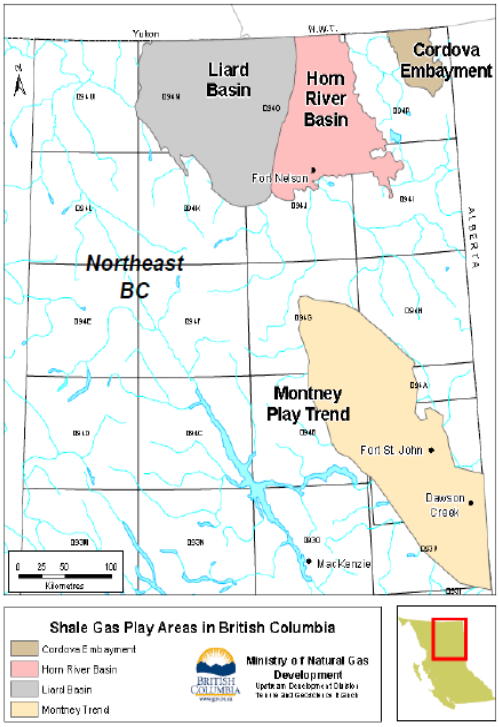
Horn River Basin – Devonian
- 11,400 square kilometres
- OGIP – 448 Tcf, Marketable – 78 Tcf
- 200 wells producing (Feb. 2014)
- Daily production – 492 MMcf/d
- Cumulative production – 635 Bcf

Cordova Embayment – Devonian
- 2,690 square kilometres
- OGIP – 200 Tcf, Marketable – 20 Tcf
- 19 wells producing (March 2014)
- Daily production – 30 MMcf/d
- Cumulative production – 25 Bcf

Montney – Triassic
- 29,850 square kilometres
- OGIP – 1,965 Tcf, Marketable – 271 Tcf
- 1,644 gas wells producing (March 2014)
- Daily production – 2.26 Bcf/d
- Cumulative production – 2.53 Tcf

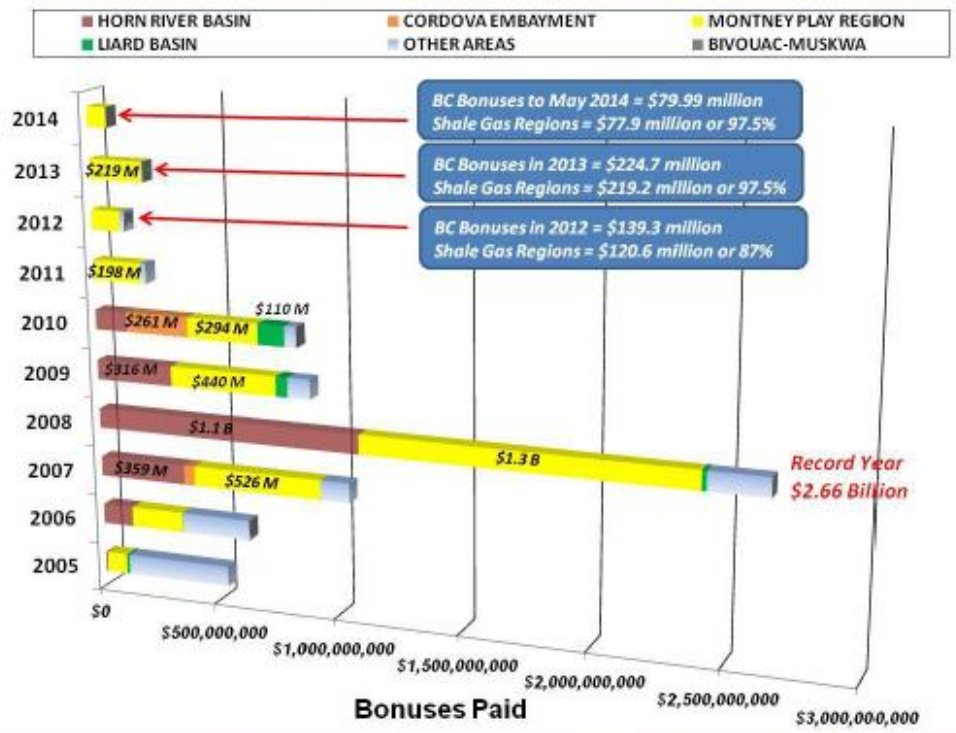
Total GIP estimates of approx. 2,900 Tcf

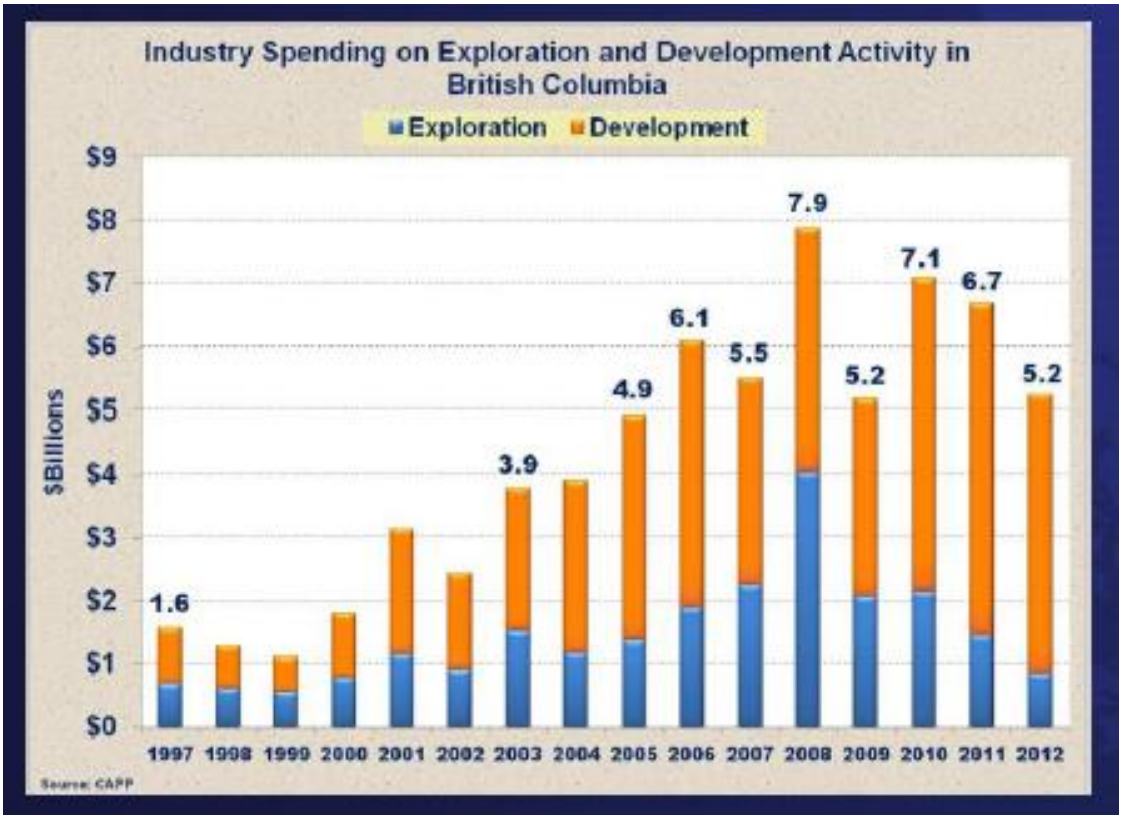
Over 400 Tcf marketable



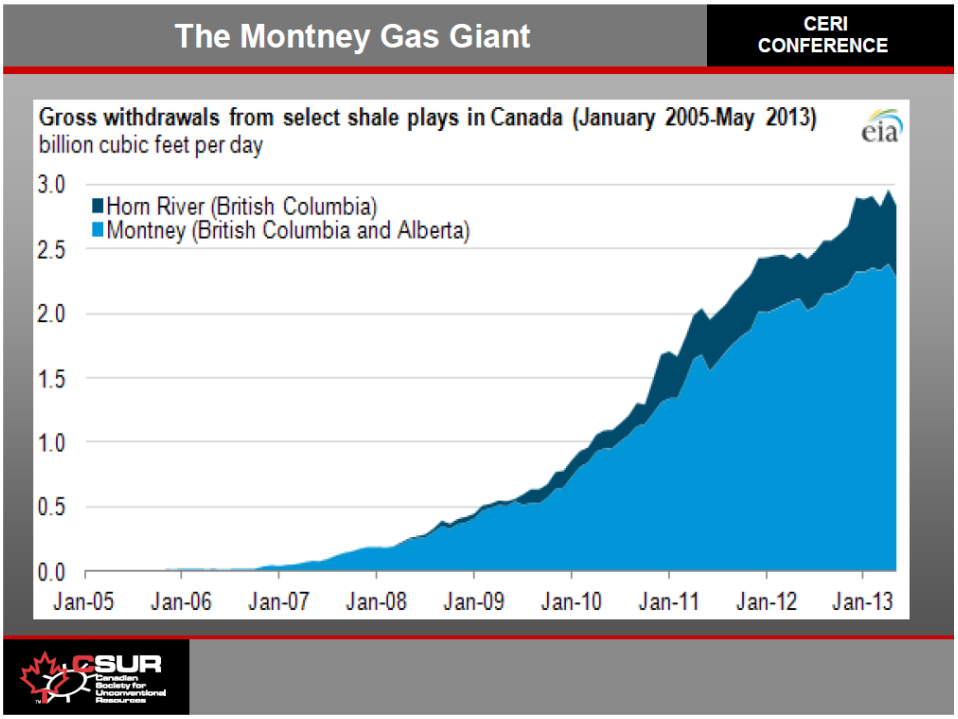
6

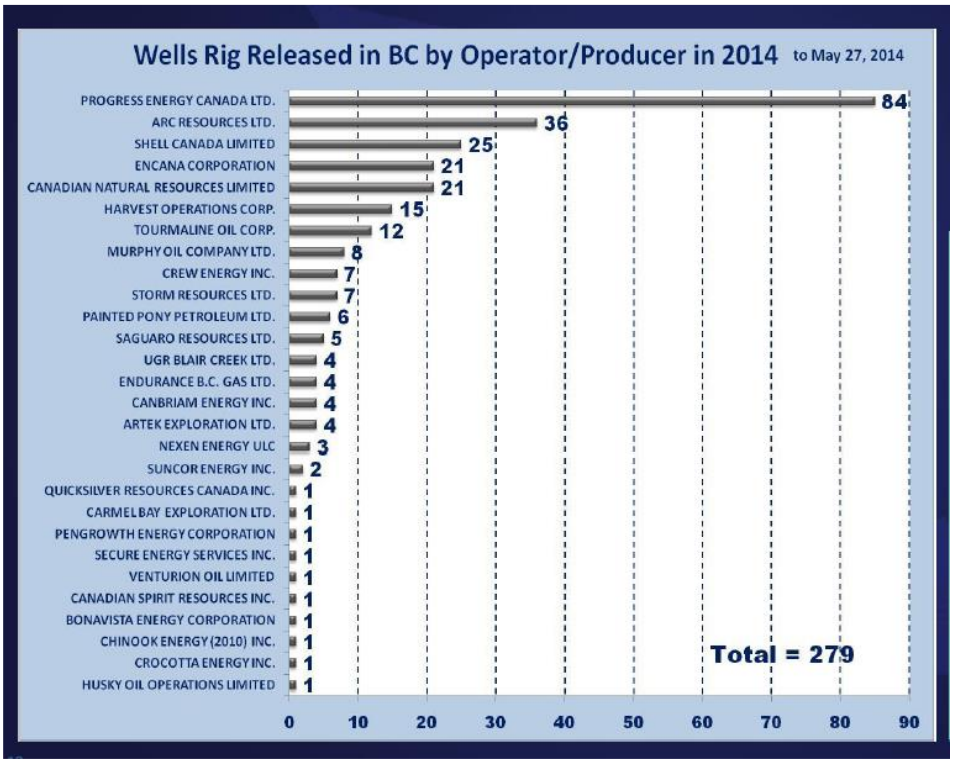
Bonuses Paid for PNG Rights in BC's Shale Gas Regions





The gas production for the Horn River and Montney as presented by D. Allan.
http://www.csur.com/images/CSUG_presentations/Allan_presentation_CERI_2014_Natural_Gas_Confernce.pdf



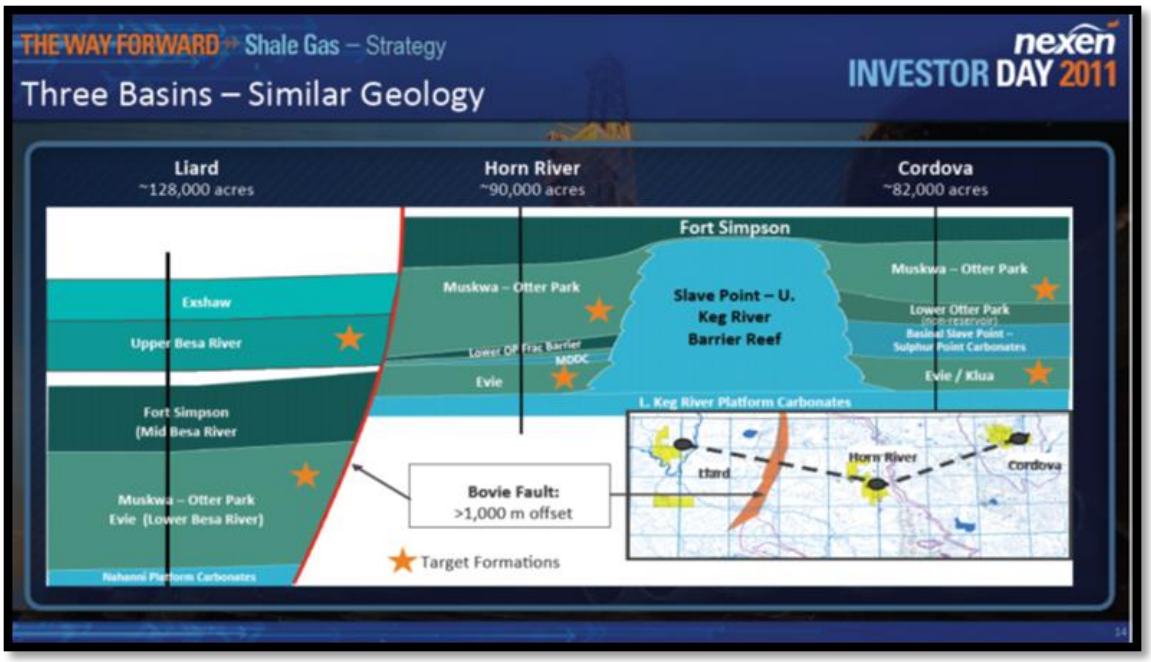


Upper and Middle Devonian, Evie (Klua), Otter Park and Muskwa members of the Horn River Formation Horn River Basin, Cordova Embayment and the Liard Basin

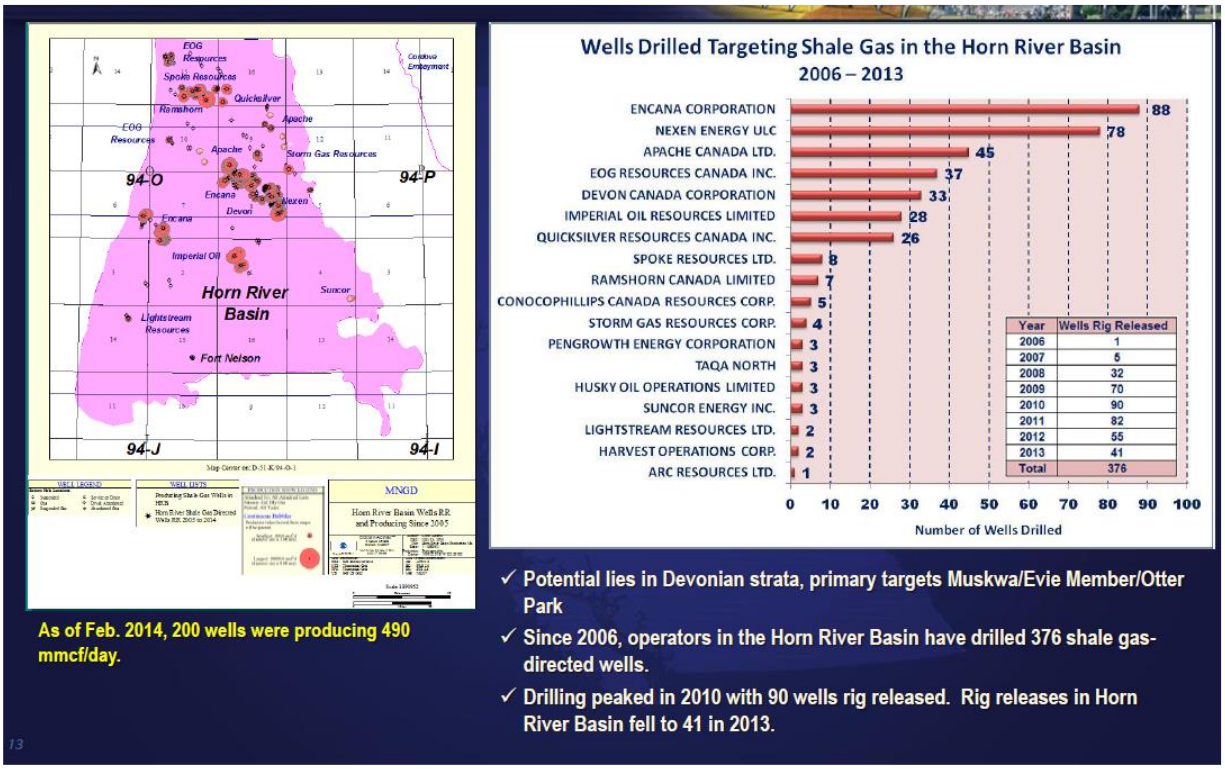
Of these very far north basins, the Horn River has the most activity. As of Dec. 2014 there were 200 wells producing 500 MMCF/D. increasing from roughly 80 MMCFD at the end of 2009 and a cumulative gas production of approximately 770 BCF. As a result of current economic conditions there has not been any significant new development drilling programs initiated in the past few years.

Horn River Basin Unconventional Shale Gas Play Atlas JUNE 2014 | BC Oil and Gas Commission

http://www.bcogc.ca/node/11238/download

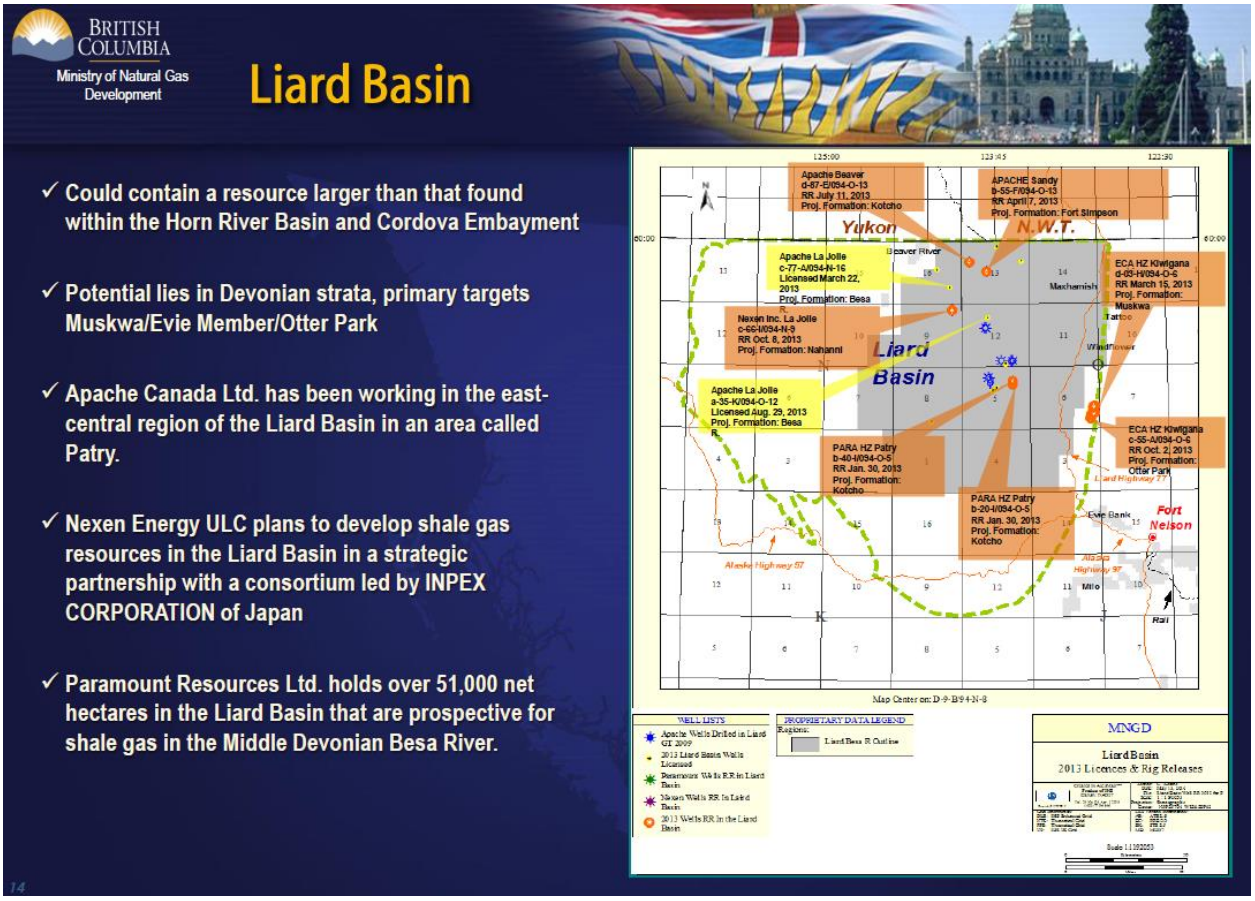


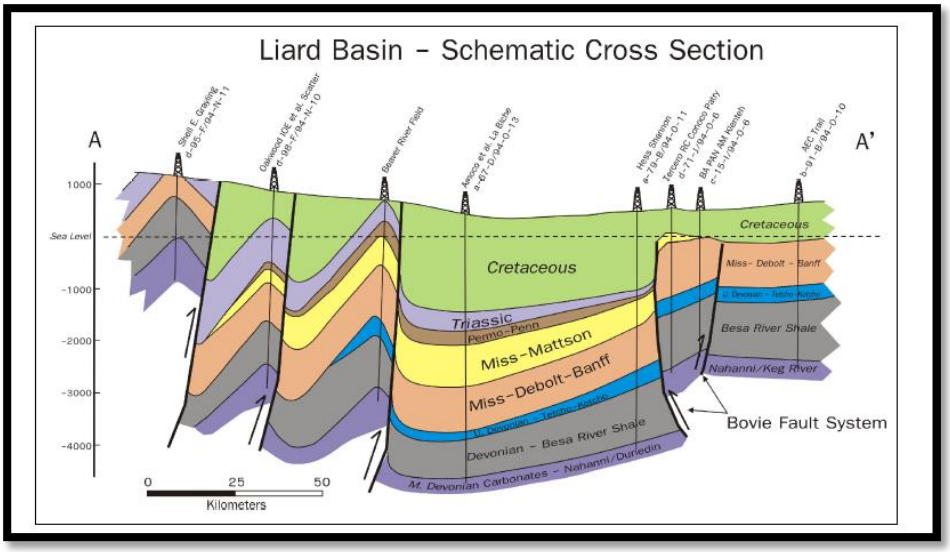
The seven companies with the most drilling, as of end of 2013 were Encana, Nexen, Apache, EOG, Devon, Imperial Oil and Quicksilver. The potential lies within the Muskwa/Evie Member/Otter Park.



The Liard Basin, straddling the Yukon, North West Territory and British Columbia, containing has great potential with 3 million acres and 5 kilometres of section from the Cambrian to the Upper Cretaceous. It remains relatively unexplored with only a few recent shale-targeted wells but Houston-based independent Apache Corp. calls the Lower Besa River black shale "the best unconventional gas reservoir evaluated in North America with excellent vertical and lateral reservoir continuity."

http://www.ogj.com/articles/print/vol-110/issue-8b/regular-features/journally-speaking/liard-and-the-besa-river.html



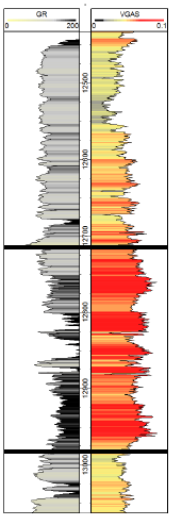


From Apache presentation Jun 2012.

http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=6&cad=rja&uact=8&ved=0CEwQFjAF&url=http%3A%2F%2Ffiles.shareholder.com%2Fdownloads%2FAPA%2F2148221537x0x577564%2Fd3ace688-47ba-48e4-8179-83b15adb6881%2FApache_Investor-Day_20120614.pdf&ei=NJg4U53sA-66yAGXsoDACQ&usg=AFQjCNHNYyC2VdJ9Etmrv3Uxkf8KzrfBRw&bvm=bv.63808443,d.aWc

LIARD BASIN

BEST UNCONVENTIONAL GAS RESERVOIR IN NORTH AMERICA



Reservoir	Units	Liard	NE-PA Marcellus	Haynesville
Depth	(ft)	9500 - 15000	7000 - 11000	10000 - 13000
Thickness	(ft)	400 - 1000	150 - 400	100 - 300
Porosity	(%)	3 - 8	6 - 12	4 - 7
Water Saturation	(%)	15 - 20	15 - 45	20 - 40
OGIP / Sec	(BCF)	170 - 500	30 - 200	50 - 100
Thermal Maturity	(VRo)	>1.5	>1.6	>1.7
Pressure	(Psi/ft)	0.85 - 0.92	0.5 - .65	~0.85
GOR		Dry Gas	Dry Gas	Dry Gas
Quartz+Carb	(Vol %)	>90	65 - 90	60 - 70
TOC	(Wt. %)	3 - 6	2 - 10	2 - 4

- Lower Besa River First Black Shale
- Best gas-shale reservoir evaluated in North America
- Excellent vertical and lateral reservoir continuity

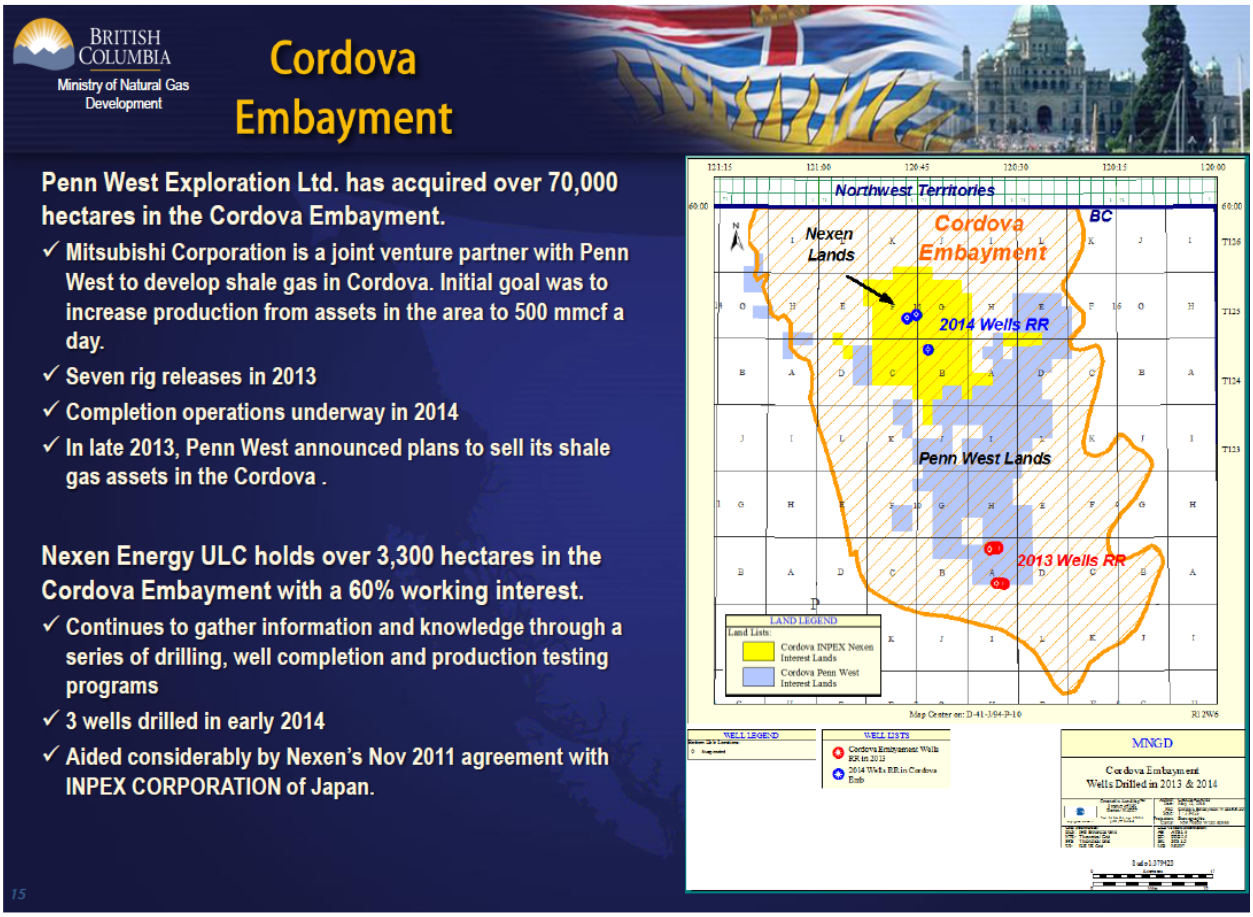
Gas Filled Porosity

In 2012, Apache, with 430,000 acres, reported that one of their wells (Apache HZ Patry d-34-K/94-O-5) recorded a 30 day initial production rate of 21.3 MMCF/D on a six-stage fracturing operation (3.6 MMCF/D per hydraulic fracture). The well was drilled in 2010 to a vertical depth of 3843 m with a horizontal leg of 885 m and has an estimated ultimate recovery (EUR) of 17.9 BCF. It is considered to be one of the best shale gas resource tests in any of North America's unconventional reservoirs (Apache Canada Ltd., 2012).

Apache is targeting the Upper Devonian Lower Besa River Black Shale and estimates that its Liard Basin lands carry a net gas-in-place of 201 TCF, which could yield net sales gas of 48 TCF. The shale is 400-1,000 ft. thick lying at depths of 9,500-15,000 ft. Porosity range is 3-8% and water saturation is 15-20%. Total organic carbon values are 3-6 wt. %. Apache showed a development model that would involve recovery of 54 TCF of raw gas using 731 well locations on 61 pads with two drilling rigs per pad

The company's vertical C-86-F well went to 15,000 ft. and had a 30-day initial potential of 9.8 MMCFD, and the vertical D-28-B well went to 13,200 ft. and flowed 4.6 MMCFD. The two vertical wells had only a single frac apiece. Net pay thickness is 1,024 ft. at C-86-F and 708 ft. at D-28-B. In its development model, Apache envisions drilling horizontal wells with 7,050-8,040-ft laterals with 18 fracs per lateral. The company estimates 400 ft. spacing between fracs and 600 m between wells. Drilling time is 110-120 days/well. The company plans to drill tenure wells in this year's second half followed by more concept wells in 2013.

The Cordova Embayment area, an area of 936,000 acres where most blocks of land were purchased in 2007, is now being drilled. B.C. has an experimental scheme ownership where operations are kept confidential for three years of which Nexen, Penn West and Canadian Natural Resources Ltd. have participated.

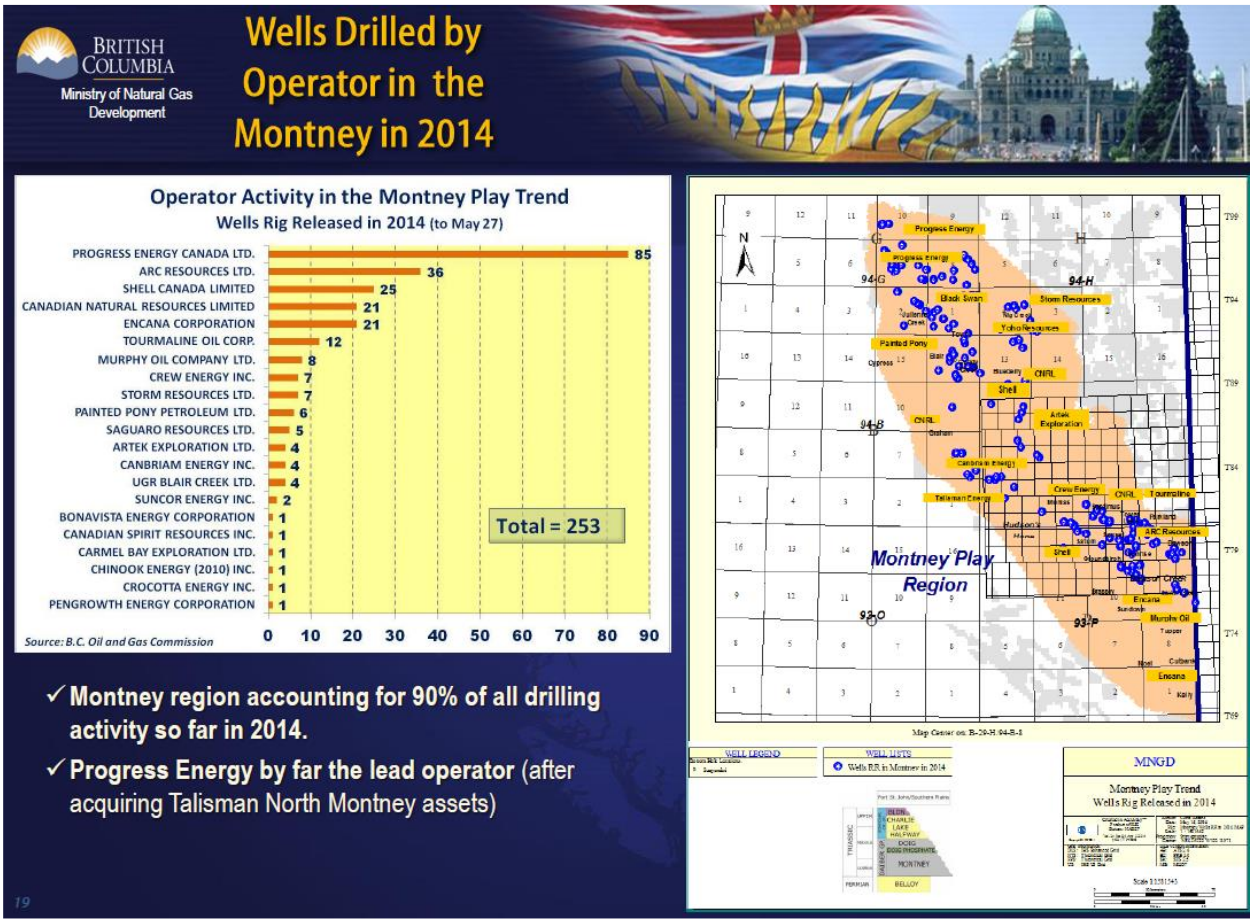


Triassic Doig and Montney Fort St. John/Dawson Creek Area

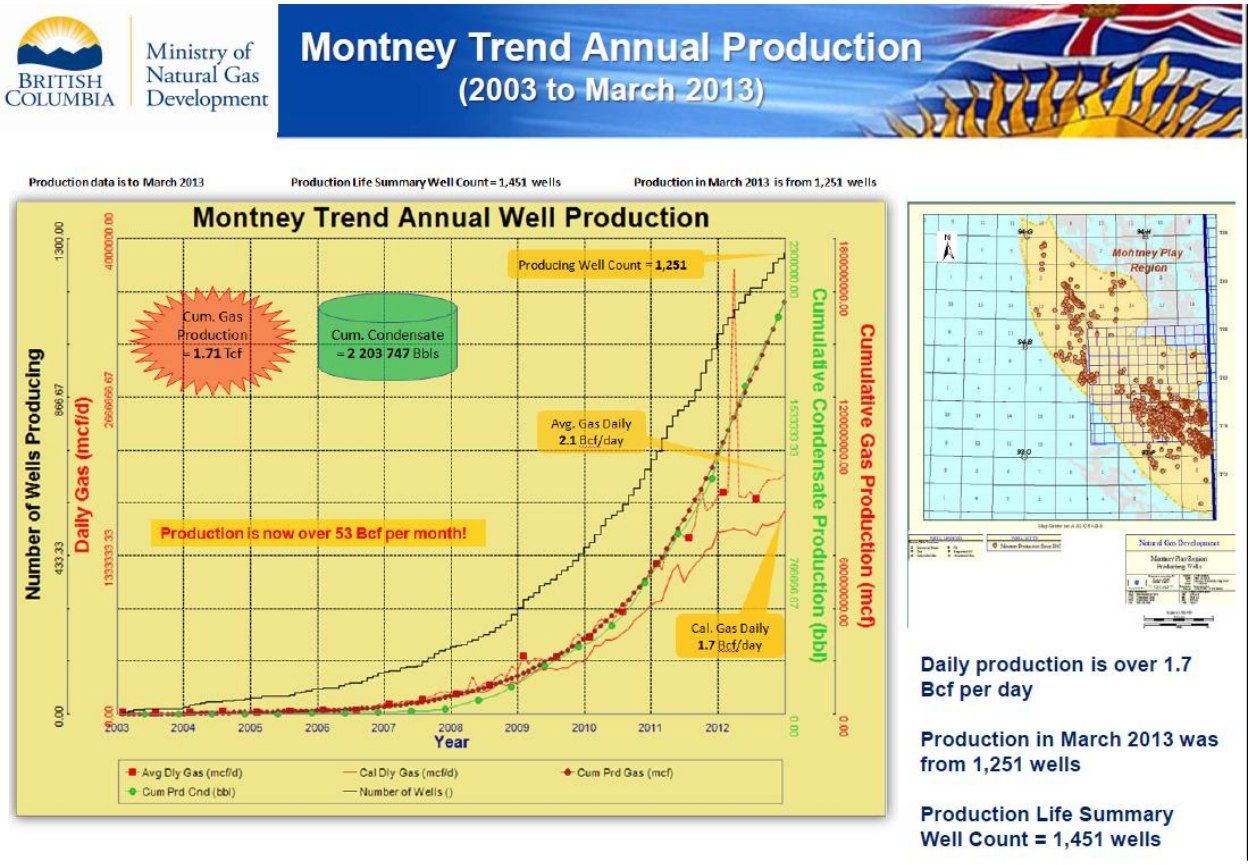
The Montney is a liquids-rich tight gas/shale gas play, with cumulative production as of Dec 2014 at 3.2 Trillion Cu FT and now producing at more than 2.8 BCFD. There are some projections that it double by 2020. This Montney Play Trend, of 6.6 million acres, is now one of the most active natural gas plays in North America. The primary zones are the Upper Middle and Lower Montney as well as the Doig and Doig Phosphate. The major facies include fine-grained shoreface, shelf siltstone to shale, fine-grained sandstone turbidites, and organic rich phosphatic shale. This play varies from the traditional distal shale facies along the Alberta/British Columbia border to a tight calcareous siltstone and sandstone in Central Alberta. The current trend for companies is to explore up dip towards the "oil window" in search of liquids-rich gas. The top six Montney players out of the more than twenty two, in order of rig utilization, are Progress Energy Ltd., ARC Resources, Shell Canada Ltd, Canadian Natural Resources, Encana Corp., and Tourmaline Oil Corp.

Montney Formation Play Atlas NEBC October 2012 | BC Oil and Gas Commission

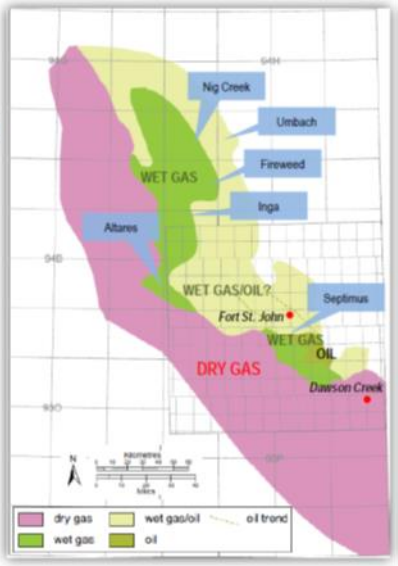
http://www.bcogc.ca/node/8131/download



The graph below shows the well production in the Montney from the Adams, 2013 report.



- Large proportion of the Montney play has economically benefitted by the presence of liquids rich gas.
- Focused development of the Montney wet gas trend began in 2009/2010 as natural gas commodity prices were falling.
- The current rate of development is not only an indication of the more favourable reservoir characteristics *(porosity, organic carbon content, pressures)*, but also a reflection of the higher natural gas liquid *(C2–C4)* and condensate *(C5–C12)* concentrations of the formation.
- Producers continue to push the limits of the northeastern, liquids-rich portion of the fairway.

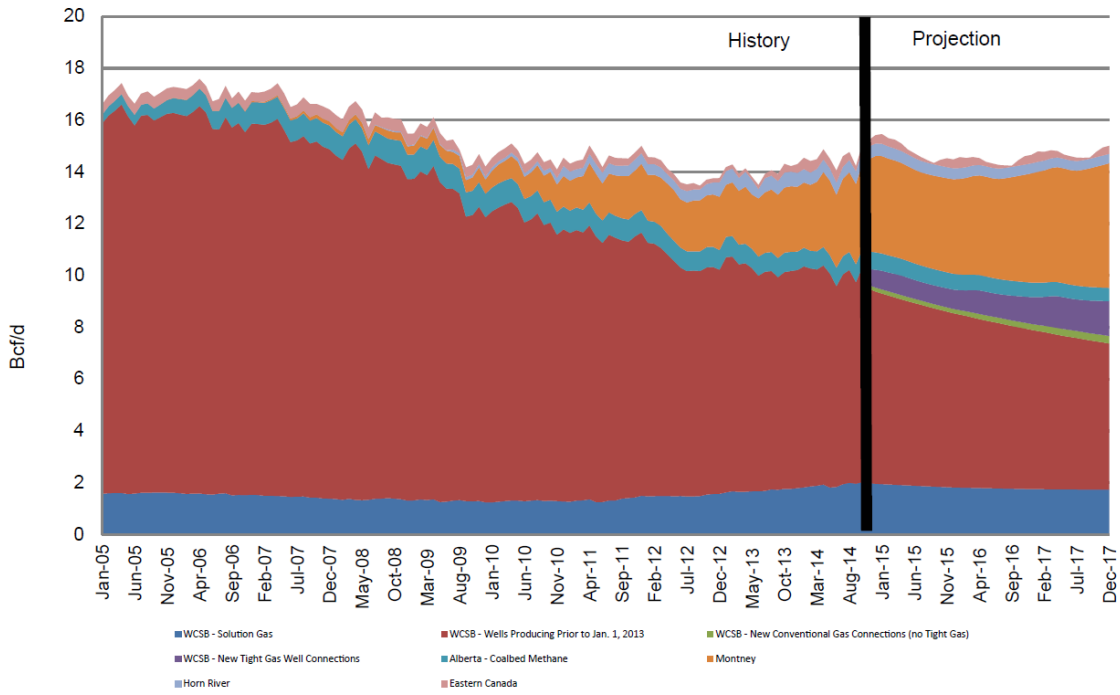


Zones of dry gas, wet gas, wet gas+oil, and oil within the Montney Formation (derived from sales gas data). *Source: Geoscience Reports 2013, BC Ministry of Natural Gas Development*

The graph below shows the gas deliverability 2004 to 2015. Note the increasing Montney contribution. https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ntrlgsdlvrblty20152017/ntrlgsdlvrblty20152017ppndc-eng.pdf

FIGURE C.1

Outlook for Canadian Gas Deliverability – Mid-Range Price Case



The following table is from Adams, 2013.

Parameter	Shale Gas Play					
	Horn River Basin	Montney (B.C. only)	Barnett	Marcellus	Haynesville	Fayetteville
Basin Area (km^2)	11 500	1 600 to 10 000	1 900	95 000	9 000	9 000
Depth (m)	1 800 to 3 000	1 000 to 3 500	2 000 to 2 600	2 500 to 3 000	3 000	350 to 2 300
Thickness (m)	50 to 350	50 to > 300	15 to 182	12 to 275	75	16 to 180
Porosity (%)	2 to 8	1 to 6	4 to 5	10	8 to 9	2 to 8
Total Organic Content (%)	1 to 8	1 to 7	4.5	3 to 12	0.5 to 4.0	4.0 to 9.8
Reservoir hydrocarbons	dry gas	wet gas, dry gas	wet gas, dry gas	wet gas, dry gas	dry gas	dry gas
Natural Fracturing	Yes	Yes	Yes	Yes	Yes	Yes
Pressure regime	Overpressured	Overpressured	Overpressured	Normal to overpressured	Overpressured	Normally pressured
Proximity to major consuming markets	Distant	Distant	Close	Very close	Close	Close
GIP (billion m^3)	12 629 (10 466 to 14 894)	2 270 to 19 800	9 263	42 492	2 0311	1 473
GIP (Tcf)	448 (372 to 529)	80 to 700	327	1 500	717	52
Marketable (billion m^3)	2 198 (1 715 to 2 714)	Uncertain	1 246	7 422	7 110	1 178
Marketable (Tcf)	78 (61 to 96)	Uncertain	44	262	251	41.6
State of development	very early	early	medium	early	medium	medium
Notes:		hybrid shale/tight-gas				

Source: U.S. data from U.S. Department of Energy *Modern Shale Gas Development in the United States: A Primer*

The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta, November 2013 NEB

Table 1. Ultimate potential for Montney unconventional petroleum in British Columbia and Alberta.

Hydrocarbon Type	In-Place			Marketable		
	Low	**Expected**	High	Low	**Expected**	High
Natural Gas – billion m^3	90,559	**121,080**	153,103	8,952	**12,719**	18,257
(trillion cubic feet)	(3,197)	**(4,274)**	(5,405)	(316)	**(449)**	(645)
NGLs – million m^3	13,884	**20,173**	28,096	1,540	**2,308**	3,344
(million barrels)	(87,360)	**(126,931)**	(176,783)	(9,689)	**(14,521)**	(21,040)
Oil – million m^3	12,865	**22,484**	36,113	72	**179**	386
(million barrels)	(80,949)	**(141,469)**	(227,221)	(452)	**(1,125)**	(2,430)

[19] NEB. *Canada Energy Overview 2012*, 2013. Available at: www.neb-one.gc.ca.

[20] NEB. *Natural Gas Supply Costs in Western Canada in 2009*, 2010. Available at: www.neb-one.gc.ca.

[21] NEB. *Short-term Canadian Natural Gas Deliverability 2013-2015*, 2013. Available at: www.neb-one.gc.ca.

[22] NEB. *Canada's Energy Future: Energy Supply and Demand Projections to 2035*, 2011. Available at: www.neb-one.gc.ca.

https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ltmtptntlmntnyfrmtn2013/ltmtptntlmntnyfrmtn2013-eng.html

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. The Buckinghorse Formation is about 1000m thick in some places.

Infrastructure

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 2,900 kilometres (1,800 miles) of natural gas transmission pipeline which can transport 2.9 BCFD. TransCanada Corp keeps expanding their pipeline infrastructure to meet supply and demand. In April 2015 the National Energy Board issued its report recommending the federal government approve the TransCanada proposed North Montney Mainline Project which will add approximately 301 km of pipeline in to the existing system.

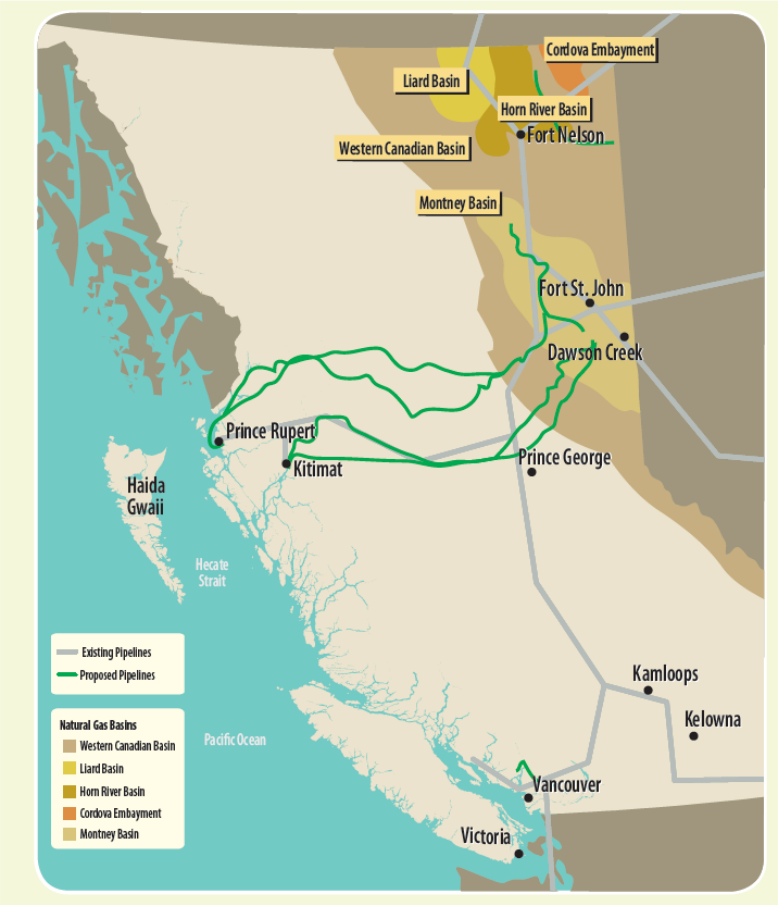
With all these gas resources, which are mostly unconventional, the Asian gas market is now being targeted by 19 (11 in 2013) joint venture export groups with the building of LNG terminals with their pipeline routes in Kitimat, Prince Rupert and Grassy Point BC, 643 kilometers north of Vancouver. These projects, details and partners are ever changing with the summary, as of June 2014, below, (10 out of the 19 with 16 BCF/D accounted for):

Kitimat LNG (Chevron, Apache) 1.4 BCF/D, Permits received (including Export License); awaiting investment decision, **BC LNG Export Co-operative**, 0.125 BCF/D, Permits received (including Export License), **LNG Canada** (Shell, KOGAS, Mitsubishi, PetroChina),2.0 – 3.2 BCF/D, Feasibility stage; applied for some permits; Export License granted, **Pacific Northwest LNG** (Petronas, Japex, Indian Oil Corp., Pet. Brunei, SINOPEC) 2.6 BCF/D (at full build out), Applying for environmental permits, Export License granted, **Aurora LNG** (Nexen/Inpex), Conducting feasibility; Export License granted**, Prince Rupert LNG** (BG Group), 3.0 BCF/D, Advancing feasibility, Export License granted, applying for environmental permits, **Triton LNG** (AltaGas/Idemitsu Kosan) ,0.3 BCF/D, Conducting feasibility; Export License granted, **ExxonMobil/Imperial Oil** (WCC LNG Ltd.) 4.0 BCF/D, Granted Export License, **Woodfibre LNG,** 0.3 BCF/D, Granted Export License, **Woodside** (Grassy Point LNG),1.8 BCF/D, Conducting feasibility

The BC government has summed up this project with 20 proposed LNG projects, 13 NEB export licences and 34 project partners. https://engage.gov.bc.ca/lnginbc/lng-projects/

http://www.ceri.ca/images/stories/Examining_the_LNG_LPG_Puzzle_June_21_2014_Final.pdf

The following diagrams shows the proposed pipelines to the coast.



Other BC Information and Links

http://www.capp.ca/publications-and-statistics/publications/266489

http://www.csur.com/misc/Oilweek_Top_%20100_%20Breakfast_%20June%2012.pdf

http://engage.gov.bc.ca/lnginbc/

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://www2.gov.bc.ca/gov/content/industry/natural-gas-oil/petroleum-geoscience/statistics-industry-activity

http://www.bcogc.ca/publications/reports

BC MEM/NEB Report, May 2011: Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin

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

Geoscience BC is an industry-led, industry-focused, applied geoscience organization.

Their mandate is to encourage mineral and oil & gas exploration investment in British

Columbia though the collection, interpretation and marketing of publically available.

Some of their major projects have been aquifer studies.

- The B.C. government announced in July 2015 an investment of $5 million in Geoscience BC to support mineral, water and energy earth science in British Columbia

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

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

http://hornrivernews.com/

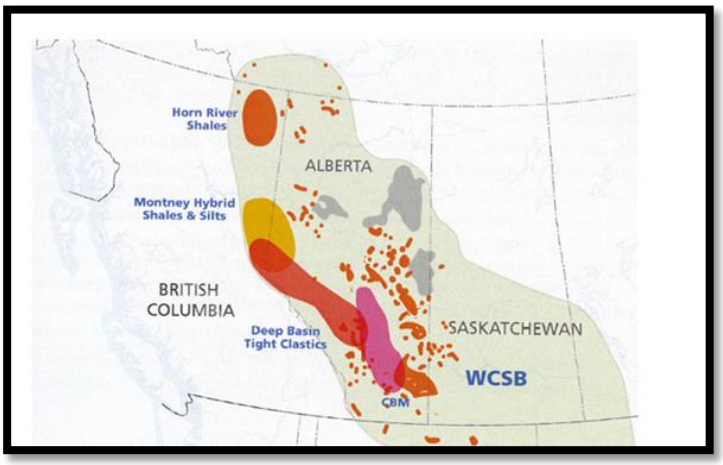
ALBERTA

Note that the recent oil price collapse has changed the dynamics of this industry dramatically especially for Alberta, creating a challenge in the updating for this report.

The shales and tight rocks of the Western Canada Sedimentary Basin have been under investigation for the last number of years. The Alberta portion of this basin, Alberta Basin, has been studied thoroughly by Alberta Energy Resources Conservation Board (ERCB), Alberta Geological Survey (AGS), Geological Survey of Canada (GSC) and National Energy Board (NEB).

Alberta has extensive experience in the development of energy resources and has a strong regulatory framework already in place. Shale gas and liquids 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.

Estimates of shale resources within the Western Canada Sedimentary Basin (see map below) vary from 86 to 1000 TCF. This early estimate did not include liquid phase. While there is a huge potential in Alberta, commercial shale production is at early stages but additional new plays have suddenly begun to emerge.



In Oct 2011 the NEB published the "Tight Oil Developments in the Western Canada Sedimentary Basin" which included Plays highlighted are the Bakken/Exshaw Formation (Manitoba, Saskatchewan, Alberta, and British Columbia), Cardium Formation (Alberta), Viking Formation (Alberta and Saskatchewan),Lower Shaunavon Formation (Saskatchewan), Montney/Doig Formation (Alberta), Duvernay/Muskwa Formation (Alberta), Beaverhill Lake Group (Alberta) and Lower Amaranth Formation (Manitoba). The list did not include potential formations, such as the Second White Specks, Nordegg, and Pekisko and others, largely because these new developments are at very early stages. The NEB estimated that Canadian tight oil production, at March, 2011, to be over 160,000 BBL/D. It is too early to estimate with any degree of confidence what the ultimate impact of exploiting tight oil plays in western Canada might be; however, there are some indications. The Alberta Energy Resources Conservation Board's latest Supply and

Demand report estimates that Alberta's tight oil plays will add an additional 170,000 BBL/D to conventional light oil production by 2014. In Saskatchewan, tight oil production in the first quarter of 2011 was 90,000 BBL/D, while Manitoba, reached 25,000 BBL/D. Companies have so far identified just over 500 million barrels of proved and probable reserves in their plays of interest and not all companies active in those plays have issued formation-specific reserves. This is enough oil to provide production of about 134,000 BBL/D over a period of 10 years. As well, the technologies used to develop tight oil will continue to evolve, likely increasing the amount of recoverable oil from these plays.

Since 2007, the various governments have been collecting and still in the progress of collections data on the following formations: Colorado Group-First White Speckled Shale, Puskwaskau, Wapiabi, Colorado Shale, Muskiki, Second White Speckled Shale, Blackstone, Kaskapau, Fish Scales, Shaftesbury, Joli Fou, Wilrich Formation, Bantry Shale member, Fernie Formation, Fernie Shale, Pokerchip Shale, Nordegg, Rierdon, Montney, Lower Banff, Exshaw, Duvernay and Muskwa.

In October 2012 a very comprehensive study was published by Rokosh et al.: "Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbons". This study concluded that the shale gas resources (hydrocarbon endowment) in Alberta alone are estimated to be 3,424 TCF of natural gas, 58.6 Billion Barrels of NGL's, and 423.6 Billion Barrels of oil. They evaluated the geology, distribution, characteristics, and hydrocarbon potential of key shale and/or siltstone formations (units) in Alberta. Five units show immediate potential: the Duvernay Formation, the Muskwa Formation, the Montney Formation, the Nordegg Member, and the basal Banff and Exshaw formations (sometimes referred to as the Alberta Bakken by industry). The study also includes a preliminary assessment of the Colorado, Wilrich, Rierdon, and Bantry Shale units. These units were systematically mapped, sampled, and evaluated for their hydrocarbon potential. In total, 3385 samples were collected and evaluated for this summary report. The following table and 4 maps are from this report.

Table 1. Summary of estimates of Alberta shale- and siltstone-hosted hydrocarbon resource endowment.

Unit	Adsorbed Gas Content %*	Natural Gas (Tcf)	Natural-Gas Liquids (billion bbl)	Oil (billion bbl)
Duvernay P50	6.8	443	11.3	61.7
Duvernay P90–P10	5.6–8.5	353–540	7.5–16.3	44.1–82.9
Muskwa P50	6.9	419	14.8	115.1
Muskwa P90–P10	4.1–10.5	289–527	6.0–26.3	74.8–159.9
Montney P50	17.7	2133	28.9	136.3
Montney P90–P10	10.8–26.0	1630–2828	11.7–54.4	78.6–220.5
Basal Banff/Exshaw P50 (preliminary data; see Section 5.1)	5.7	35	0.092	24.8
Basal Banff/Exshaw P90-P10	3.2–10.0	16–70	0.034–0.217	9.0–44.9
North Nordegg P50 (preliminary data; see Section 5.1)	18.2	148	1.4	37.8
North Nordegg P90–P10	4.6–34.8	70–281	0.487–3.5	19.9–66.4
Wilrich P50 (preliminary data; see Section 5.1)	33.7	246	2.1	47.9
Wilrich P90–P10	6.2–59.2	115–568	0.689–4.449	20.2–172.3
Total P50 (medium estimate) resource endowment	n/a	3424	58.6	423.6

* The percentage of adsorbed gas represents the portion of natural gas that is stored as adsorbed gas.

The resource estimates listed above provide an estimate of total hydrocarbons-in-place. Geological and reservoir engineering constraints, recovery factors, and additional economic factors, as well as social and environmental considerations, will ultimately determine the potential recovery of this large resource.

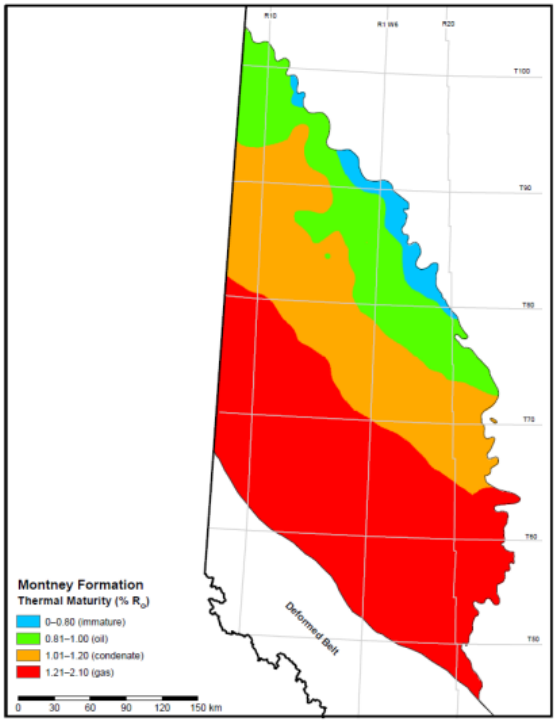


Figure 2.3.7. Thermal maturity map of the Montney Formation.

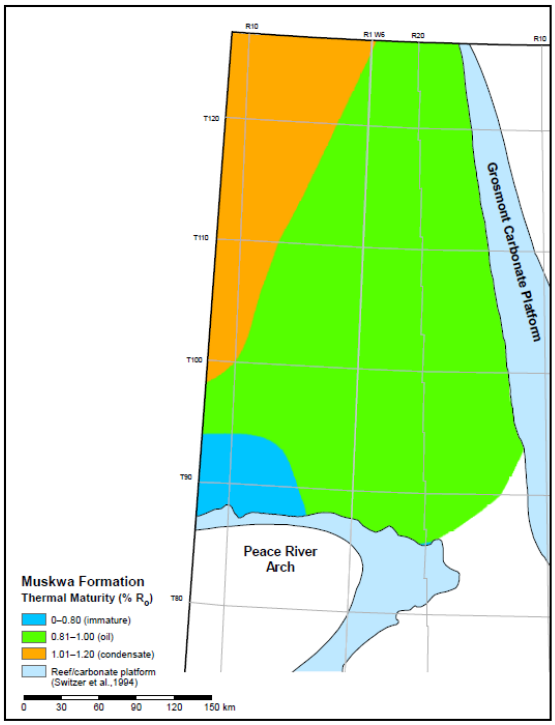


Figure 2.2.6. Thermal maturity map of the Muskwa Formation.

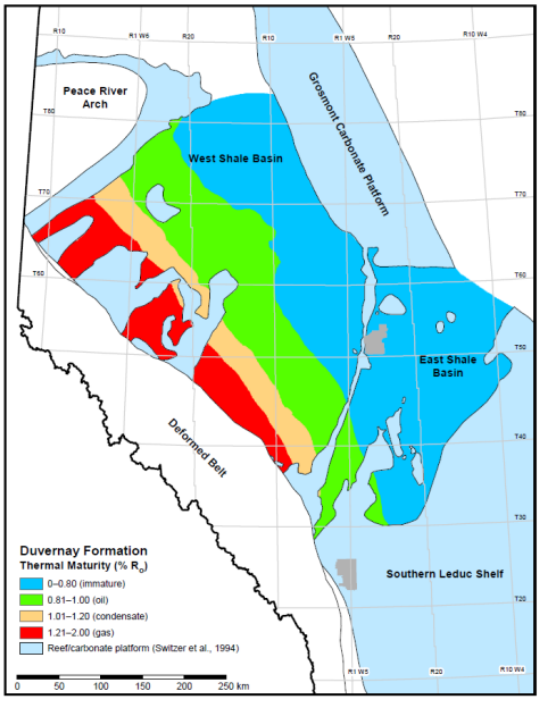


Figure 2.1.7. Thermal maturity map of the Duvernay Formation.

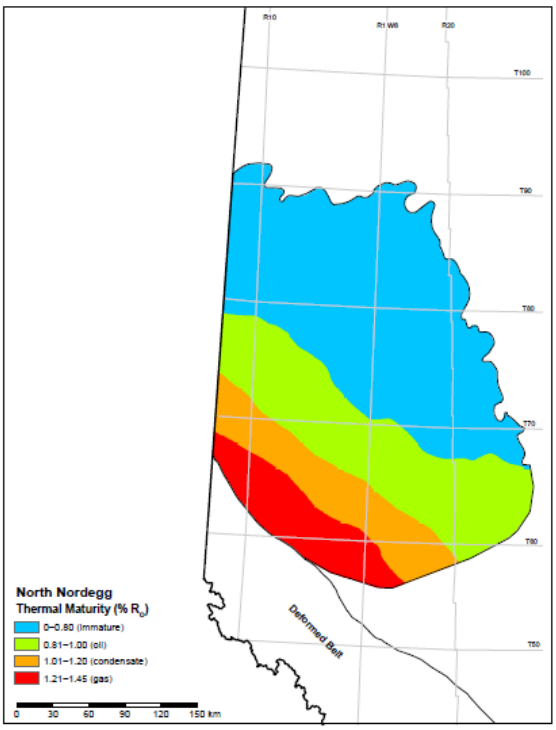


Figure 2.5.7. Thermal maturity map of the north Nordegg.

Thermal Maturity Maps of the Montney, Muskwa, Duvernay and Nordegg from Rokosh et al 2012.

Cretaceous Colorado Group

Eastern Alberta

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

Lower Jurassic Nordegg (Gordondale)

West Central Alberta

There a small number of companies playing the potential of the Nordegg Member which is a source rock composed of basinal shales, silts and carbonates.

Some companies involved or were involved are: Penn West, EOG, Apache, Surge, Nordegg, Lightstream, Altima, Long Run and others. See Meloche in references.

Triassic Montney Shale

Western Alberta

The Montney fairway extends in Alberta where this play is being picked up for both gas and liquids rich gas. Some of this Montney is classified as conventional because of facies change. Companies actively testing oil-prone Montney exploration acreage include ARC Resources Ltd. at Ante Creek and Tower, Athabasca Oil Sands at Kaybob, Celtic Exploration at Karr, CIOC at Karr and Simonette, Canadian Natural Resources Ltd. at Tower, Crew Energy Inc. at Tower, Harvest at Ante Creek, Imperial Oil at Berland, Long Run at Girouxville, RMP Energy Inc. at Grizzly and North Waskahigan, Seven Generations at Karr, and Triology Energy Corp. at Kaybob West.

In November 2013 the National Energy Board (NEB) in conjunction with their provincial agencies, an ultimate potential of the Montney was released (see below): "The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta" The following two figures are from this report.

https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ltmtptntlmntnyfrmtn2013/ltmtptntlmntnyfrmtn2013-eng.html

Table 1. Ultimate potential for Montney unconventional petroleum in British Columbia and Alberta.

Hydrocarbon Type	In-Place			Marketable		
	Low	**Expected**	High	Low	**Expected**	High
Natural Gas – billion m^3	90,559	**121,080**	153,103	8,952	**12,719**	18,257
(trillion cubic feet)	(3,197)	**(4,274)**	(5,405)	(316)	**(449)**	(645)
NGLs – million m^3	13,884	**20,173**	28,096	1,540	**2,308**	3,344
(million barrels)	(87,360)	**(126,931)**	(176,783)	(9,689)	**(14,521)**	(21,040)
Oil – million m^3	12,865	**22,484**	36,113	72	**179**	386
(million barrels)	(80,949)	**(141,469)**	(227,221)	(452)	**(1,125)**	(2,430)

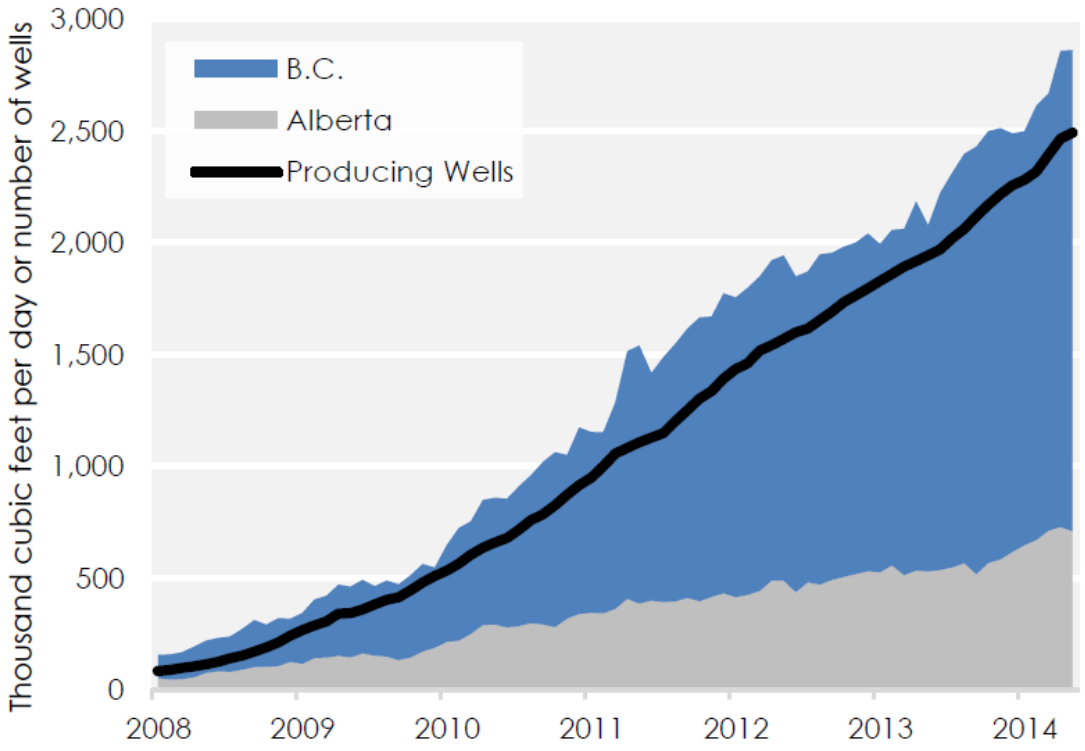
[19] NEB. *Canada Energy Overview 2012*, 2013. Available at: www.neb-one.gc.ca.

[20] NEB. *Natural Gas Supply Costs in Western Canada in 2009*, 2010. Available at: www.neb-one.gc.ca.

[21] NEB. *Short-term Canadian Natural Gas Deliverability 2013-2015*, 2013. Available at: www.neb-one.gc.ca.

[22] NEB. *Canada's Energy Future: Energy Supply and Demand Projections to 2035*, 2011. Available at: www.neb-one.gc.ca.

Figure 10 Montney Natural Gas Production



https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/dnmc/2014/2014nrgdnmc-eng.pdf

http://www.ogj.com/articles/print/volume-111/issue-4/general-interest/montney-duvernay-will-be-key-to-canada.html

Devonian Duvernay/ Muskwa Shales - Western Alberta

The Duvernay is often compared to the prolific Eagle Ford of Texas because they are both shale plays that offer a full spectrum, from dry gas through liquids rich gas to oil. In terms of the potential size of the play area, the richness of the source rock and even some of the early

production results, the Duvernay "is well on its way to being as big or bigger than the Eagle Ford," Canadian Discovery has proclaimed.

This exciting new liquids play, Duvernay Shale is the stratigraphic equivalent to the Muskwa in N.E. B.C. The Duvernay has been credited as the source rock for most of the gigantic Devonian oil and gas pools of Alberta. This zone compares favorably to other North American shale plays with its position in the liquids window, organic content, porosity, thickness and over pressuring. The Duvernay is often compared to the prolific Eagle Ford of Texas because they are both shale plays that offer a full spectrum, from dry gas through liquids-rich gas to oil. According to the Energy Resources Conservation Board, the Duvernay holds an estimated 443 trillion cubic feet of gas, 11.3 billion barrels of natural gas liquids and 61.7 billion barrels of oil. It is estimated that $4.2 was been spent on this play as of June 2012. This BMO Capital markets research report, June 2012, have a wealth of data on this play. Encana believes that this play is 2 times the size of the Eagle Ford Play.

The Duvernay play is divided into the Western and Eastern Shale Basin with the West divided into three drilling districts, Kaybob, Edson and Pembina.

The companies involved in this deep and expensive play of 3100 to 3700 m are numerous, some of which are: Celtic now Exxon (paid C$2.6 billion), Encana (Petro-China), ConocoPhillips, Husky, Athabasca, Chevron ($1.5 Billion deal to Kuwait Foreign Petroleum Exploration Corp.), Trilogy, Shell, Talisman, Yoho, Taqa North amongst others.

Encana just announced that they have driven down their well costs significantly from $30 MM in 2012 to about $10.4 MM. They have improved the well performance significantly with some wells producing more than 2,000 BOE/d after 55 days. They have accumulated a large position holding 1/3 of the high-graded liquids fairway with a well inventory (gross) of 1,400. Encana's Duvernay comparison with other shales is shown below.

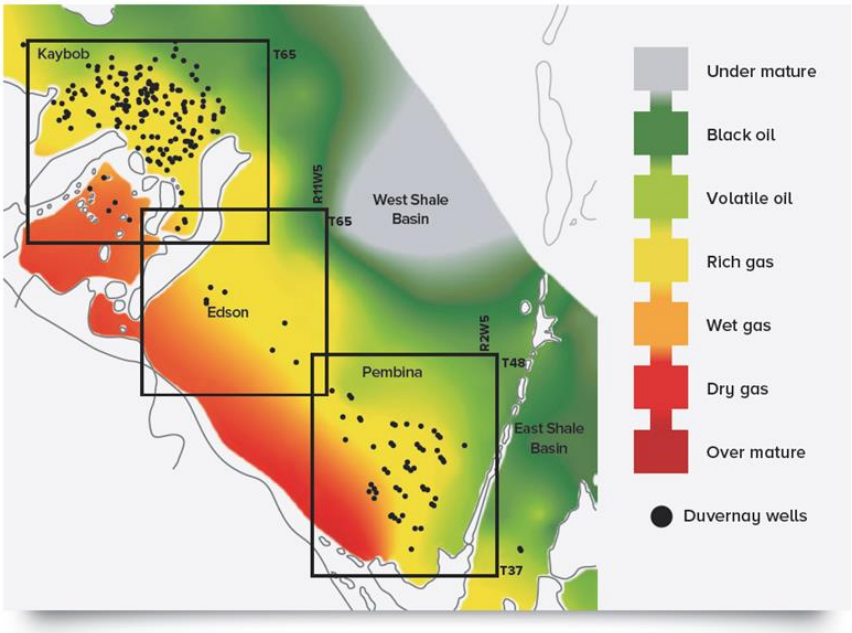
Duvernay – World Class Reservoir

Encana controls one third of the top tier land in the condensate window*

Reservoir Attribute	Duvernay	Marcellus	Eagle Ford
TVD Depth (ft)	8,200 – 13,100	400 – 8,400	8,800 – 13,800
Gross Thickness (ft)	65 – 230	50 – 200	50 – 280
Porosity (%) / Permeability (nD)	3 – 8 / 10 – 400	10 / 20 – 55	10 – 11 / 50 – 1200
Reservoir Temperature (°F)	220 – 250	130 – 170	220 – 280
Gas Composition	Wet / Dry	Wet / Dry	Wet / Dry
Total Organic content (TOC %)	1 – 20	3.0 – 12.0	4.5
Maturation (Ro %)	0.6 – 2.9	1.4 – 3.0	0.6 – 2.2
Pressure Gradient (PSI/ft)	0.72 – 0.96	0.45 – 0.60	0.60 – 0.80
EUR (MMboe / well) (6:1)	0.7 – 1.6	0.3 – 1.0	0.5 – 1.3

*Encana estimate
Source: RBC Richardson Barr / RBC Rundle estimates, industry estimates, DOE April 2009 publication "Modern Shale Gas: A Primer"

http://media.angi.s3.amazonaws.com/2015/ANGR_151001_Book_DE.pdf



Duvernay Fairway

Late Devonian and Early Mississippian Alberta Bakken – Exshaw Southern Alberta

The Alberta Bakken (Exshaw) was another emerging tight oil resource play starting in 2010 in SW Alberta to NW Montana consisting of three zones, Big Valley / Stettler Carbonates, Bakken/Exshaw dolomitic siltstones and Banff carbonates. This play has similar characteristics as the North Dakota Bakken in the Williston Basin but since it lies in the Alberta Basin it has been called the "Alberta Bakken". This play gained momentum south of the border in Montana and moved into Alberta and there was a rush to get a position. In a report a few years ago the research firm Wood Mackenzie said the tight oil play that straddles the Alberta-Montana border could contain a recoverable 2.6 billion barrels of oil. Production of about 300 to 350 BOPD has been published. There are a number of companies initially in this play. Crescent Point, Shell, Penn-West, Murphy, Torc, Argosy, Primary, Nexen, LGX (Bowood/Legacy), Rosetta and Newfield are some of the companies involved or were involved Over 30 horizontal wells have been drilled so far but with little publication of results. Press releases on this play are minimal and references to this play on their websites have disappeared so either the operators have not been as successful and/or the low oil price has slowed down activity.

Crescent Point Energy had a significant land base and drilled eight wells in the 4th quarter of 2012. Murphy drilled 6 to 9 wells with 3 producers, one being evaluated and one awaiting completion. They have announced tests of 415 to 800 BOPD. Granite Oil (Deethree Exploration) said it had two drilling rigs operating on the lands of 200,000 acres, where they have tested 600 to 950 BBL/D of 30 ° API oil. They have drilled 17 horizontal wells into this zone in 2012. Recently they are focusing on one area where they have started an EOR gas injection scheme creating higher recoveries and slowing declines. Torc has reported that two of their wells have yielded IP rates of 510 and 514 BOPD. LGX Oil + Gas Inc have recently announced success in the Banff and Big Valley Formations with rates up to 530 BOPD. See Zaitlin 2011 and 2012.

The links below provide some of the initial information when this play first came out.

http://enfieldexploration.com/wp-content/uploads/2014/01/Alberta-ABPS-Bakken-Steady-As-She-Goes.pdf

http://enfieldexploration.com/wp-content/uploads/2014/02/PIE_Industry_News_2011-03-10.pdf

Other Alberta Information and Links

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

In 2012 the Alberta Geological Survey just published a new document. Rokosh et al, Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbon Resource Potential. See the references

Alberta quarterly reports are available through this link. http://www.junewarren-nickles.com/alberta-oil-and-gas-update/

The AER is the regulator for Alberta. http://www.aer.ca/

AER May 2014 report. http://www.aer.ca/documents/sts/ST98/ST98-2014.pdf

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. The Saskatchewan natural gas production has gone from 259 BCF in 2005 to about 100 BCF in 2013. This information below will just highlight some the history.

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.

Between 2004 and 2008 more than 50 test wells were drilled for shale gas in all areas in the province, including Watrous, Moose Jaw, Strasbourg, Foam Lake, Smeaton, Shell Lake and Big River but no commercial discoveries have been announced.
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. There have been a number of smaller operators every few years announce plans but nothing seems to materialize or the company cannot be found on the internet.

Questerre announced a Pasquia Hills program. They acquired 100% interest in 39,000 high-graded net acres overlying an established oil shale deposit in one of Canada's largest oil shale deposits. They have partnered up with a USA firm uses the EcoShale In-situ capsule process which is an innovative approach that moves the machines to the rocks instead of moving the rocks to the machines to extract the oil. Drilled 16 wells in 2012 and analysis of core indicates recoveries between 10-20 gallons/ton with select intervals of up to 16-20 gallons/ton within a 20-35 m section. Further work suspended with low oil prices.

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 63,000 BOPD at the end of 2014 with a cumulative production of 26 MM M3 or 164 MM BBL. 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 light sweet crude oil with 41 ^{o}API gravity.

The marketable unconventional oil and natural gas potential of the Bakken Formation in Saskatchewan has been jointly evaluated by the National Energy Board and the

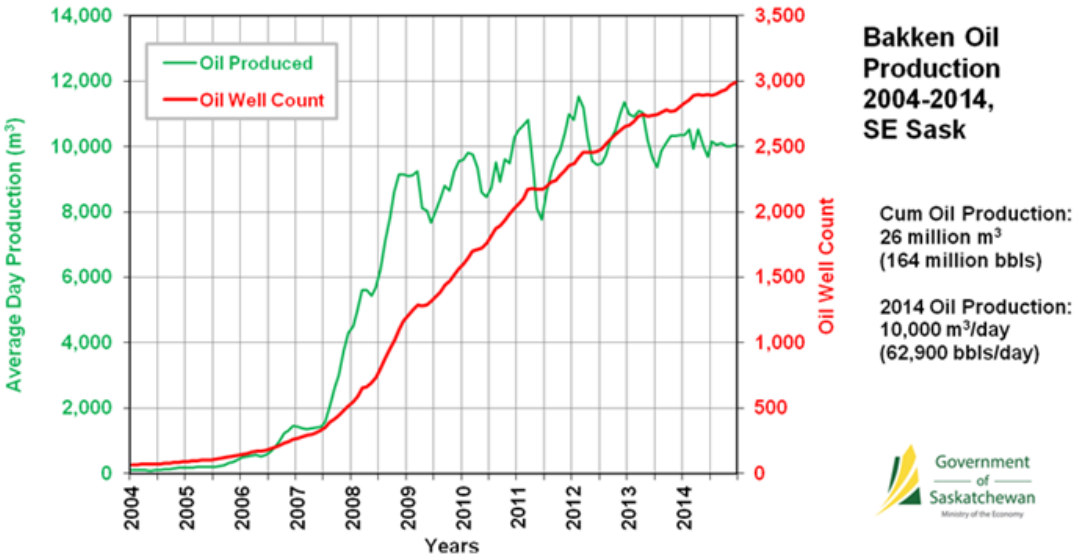
Saskatchewan Ministry of the Economy.

https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/rprt/2015bkkn/index-eng.html

Located in the southeast corner of the province, the unconventional, marketable resources of the Bakken are expected to be 223 million m3 (1,401 million barrels) of marketable oil and 81.2 billion m3 (2.9 trillion cubic feet (TCF)) of marketable natural gas.

There are many operators in this play. One of the two bigger players are Crescent Point with 914 wells drilled in 2014. Their Q4/14 production >63,000 boe/d ~4.6 billion barrels of original oil in place with a recovery factor of 3.5%. Their 25-stage cemented liner completion technique has improved overall returns, recovery factors and water consumption. PetroBakken now Lightstream is the other Bakken producer with Bakken

2015 2nd quarter production of 11,720 BOEPD and >1,050 drilling locations.



Saskatchewan Government energy and resources is the regulator.
http://www.er.gov.sk.ca/Default.aspx?DN=4c585c56-193a-485a-91fd-7c49f0104a60

MANITOBA

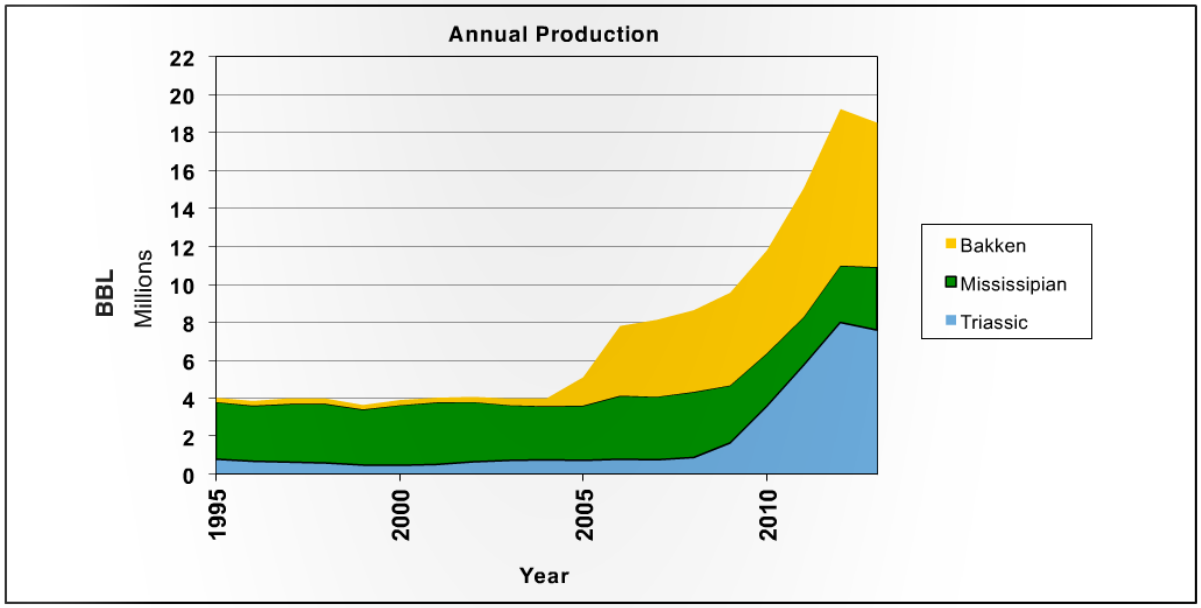
Cretaceous Colorado Group

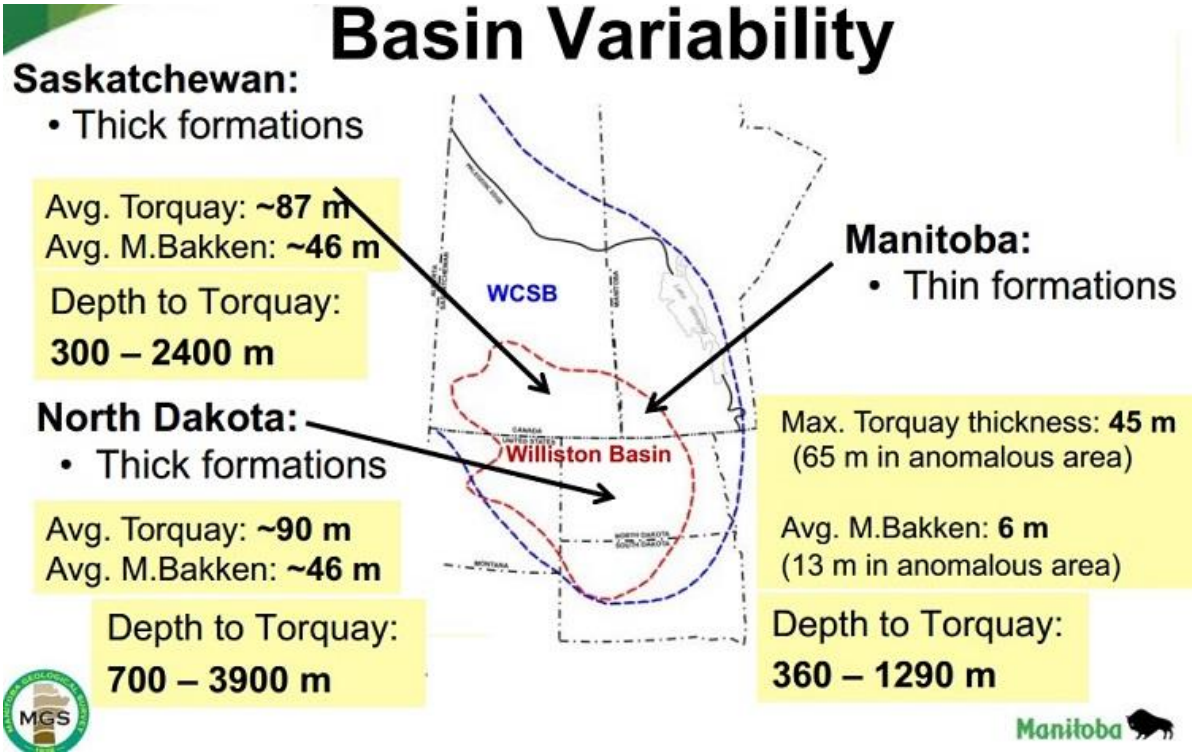
There is the potential of shale gas in Manitoba, but no activity or production. There have been a number of publications on the shallow shale potential by Nicholas and Bamburak.
http://www.wbpc.ca/assets/File/Presentation/11_Nicolas_Manitoba.pdf and Nicholas 2011
http://www.wbpc.ca/assets/File/2011%20Presentations/Tuesday/Nicolas%20WBPC%202011_Shale%20gas%20to%2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

Upper Devonian-Lower Mississippian Bakken

The production of oil from the co-mingled Bakken/Torquay, which began in the mid-1980's, continues, with about 640,740 BBL per month or 21,385 BBL/D. Cumulative historical production is 42,364,754 BBL from about 1831 producing wells The Bakken produces more water than oil so water disposal is a continuing issue. The following graph shows production from the Bakken, Mississippian and Triassic (Lower Amaranth).

The Bakken variability in the Williston Basin is summarized per province/state below.





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)

As of Aug. 2015 shale gas or shale oil are not being extracted anywhere in Ontario, and there have been no requests to explore for shale gas or shale oil even though some companies suggest future evaluation. These shales are mostly considered secondary targets but only one well has been drilled to test these zones to date.

The Ministry of Northern Development and Mines – Ontario Geological Survey has been conducting a field study of bedrock in southern Ontario to assess the bedrock's potential to host gas and to characterize the gases. The purpose of the study is to better understand the natural connection between Ontario's shale rock formations and possible implications for groundwater quality in Southern Ontario. http://www.nrcan.gc.ca/energy/sources/shale-tight-resources/17709#a3

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.

In the spring of 2010, 2 boreholes were drilled through the Kettle Point Formation. Core samples were collected to evaluate gas concentration and other key parameters. Similar work was performed in 2011 near Mount Forest in the County of Wellington to assess the shale gas potential of the Ordovician shale succession. Furthermore, in the summer of 2012, additional rock samples were collected from previously drilled wells from southern Ontario and were analyzed for mineralogy and Rock-Eval® 6 pyrolysis parameters. These analyses may assist in refining stratigraphic correlations across provincial and international borders. This project is referenced in Béland Otis 2012.

A new company was recently formed, Ontario Oil and Gas, with their total objective to acquire 60,000 acres of shale lands over the next three years. OSO currently controls 2,500 net acres and anticipates growing this quickly over the coming months.

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

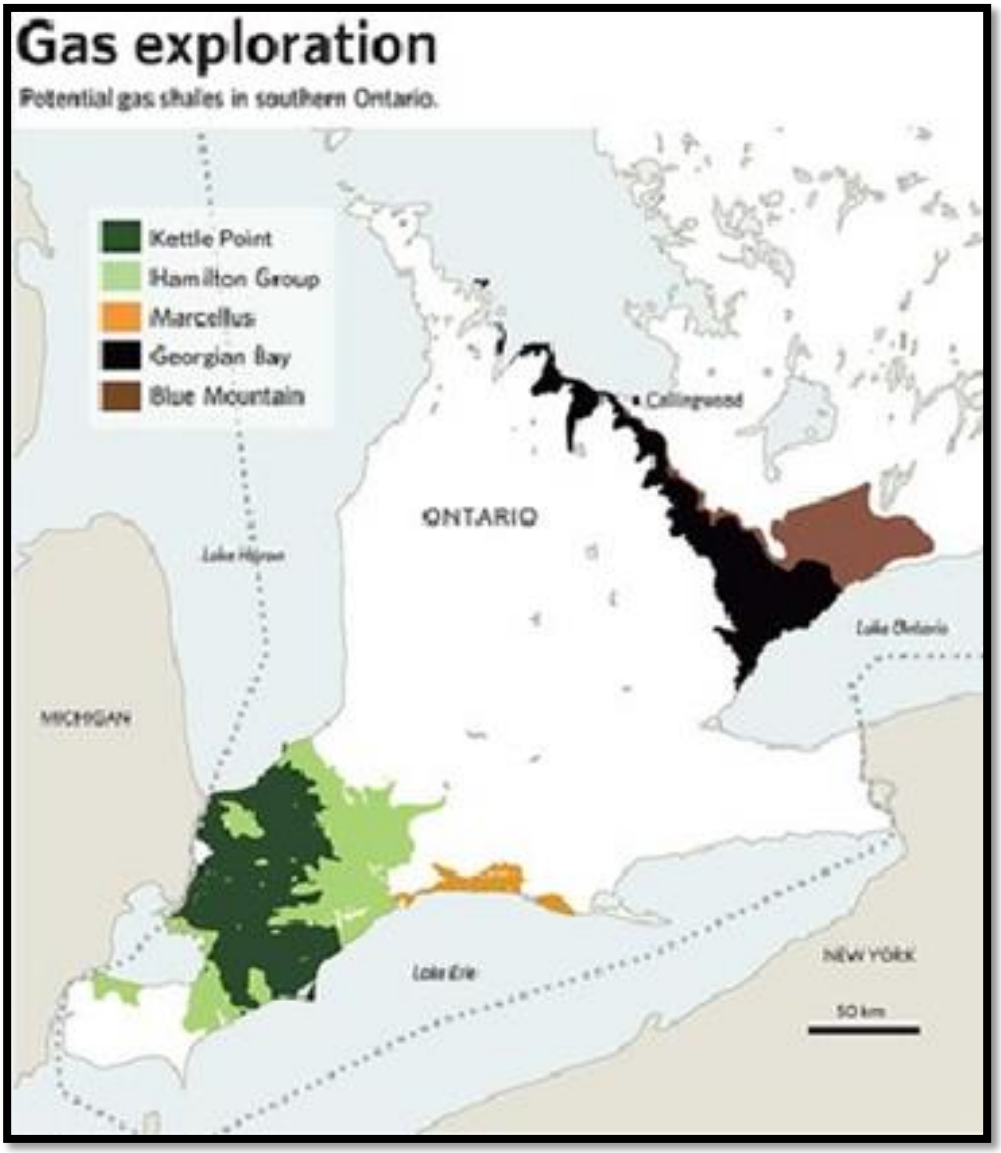
http://www.ogsrlibrary.com/

Ontario Geological Survey

http://www.mndm.gov.on.ca/en/mines-and-minerals/geoscience/non-renewable-energy

http://www.geologyontario.mndmf.gov.on.ca/mndmfiles/pub/data/imaging/OFR5716/OFR5716.pdf

http://www.geologyontario.mndmf.gov.on.ca/mndmfiles/pub/data/imaging/OFR5817/OFR5817.pdf



QUEBEC – ST. LAWRENCE LOWLANDS

Ordovician Lorraine and Utica Shale

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

Update on Hydraulic Fracturing

After six years of debate on the merits and risks of fracking, Quebec's advisory office of environmental hearings published a report in Dec 2014 that found shale gas development in the Montreal-to- Québec City region wouldn't be worthwhile. The Bureau d'audiences publiques sur l'environnement (BAPE) warned of a "magnitude of potential impacts associated with shale gas industry in an area as populous and sensitive as the St. Lawrence Lowlands."

The other shale play, which will probably require fracking in Quebec, on Anticosti Island, is being actively explored in partnership with a Government of Québec affiliate Ressources Québec.(see below)

The Government has announced they will introduce new hydrocarbon legislation as early as spring of 2016.

The Play History

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. CERI published Potential Economic Impacts of Developing Quebec's Shale Gas in March 2013.

http://www.ceri.ca/images/stories/2013-03-08_CERI_Study_132_-_Quebec_Shale.pdf

Both Forest Oil Corporation and their partners and Talisman and their partners have drilled to evaluate both the Lorraine (up to 6,500 feet thick) and the Utica (300 to 1,000 ft. thick). Talisman with their partners and a 771,000 acre land position has drilled six vertical wells with tested rates at from 300 to 900 MCFD. In 2009 and 2010 they drilled or will be drilling five horizontals which were currently being evaluated. Talisman has since suspended its shale gas exploration in Québec. http://www.theglobeandmail.com/globe-investor/talisman-suspends-shale-gas-exploration-in-quebec/article4753334/

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

See Rivard et al 2013 for a comprehensive review of this play.

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.

Corridor and Petrolia have announced a new program where coring, water wells, and data collection are expected to be completed by the end of 2012, with the final analytical results due in 2013. These results were just announced in Jan 2013. Junex has a position in Anticosti Island as well.

http://www.corridor.ca

http://petrolia-inc.com/en

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

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

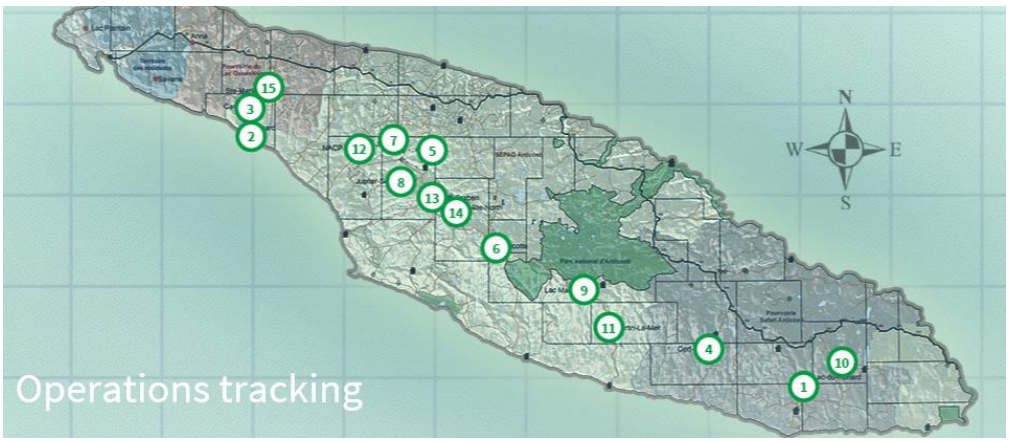
Quebec announced Feb. 13 2014 that it would move ahead with oil exploration on Anticosti with the province pledging $115-million to finance drilling for two separate joint ventures.

Anticosti Hydrocarbons L.P. is a limited partnership was created to develop oil and gas on Anticosti Island. The partners are Ressources Québec, Pétrolia Inc., Saint-Aubin E&P (Québec) Inc., and Corridor Resources Inc. Their primary objective is to demonstrate the commercial viability of oil and gas resources on Anticosti Island and to produce them.

To achieve this, Corridor Resources Inc. and Pétrolia Inc. pooled their Anticosti Island exploration licenses and transferred them to the limited partnership. On March 31, 2014, the four partners signed a partnership agreement on these 38 licenses, which cover a total area of 6,195 km². For their part, Ressources Québec and Saint-Aubin E&P agreed to finance an exploration program of up to $100 million. In 2011, Sproule Associates Limited established a best estimate of 33.9 billion barrels of oil equivalent (P50) in undiscovered resources for the licenses held.

The primary aim of the March 31, 2014 agreement between the four partners is to conduct up to $100 million in exploration work in two phases. To finance the work, Ressources Québec will invest up to $56.7 million and Saint-Aubin E&P up to $43.3 million. Pétrolia Anticosti, a subsidiary of Pétrolia, has been appointed contract operator and Saint-Aubin E&P assistant technical operator.

For the first phase, they had planned to drill 15 to 18 core holes in 2014 and 2015, followed by 3 fracking test wells in 2016. This initial phase is budgeted at between $55 and $60 million. The stratigraphic survey campaign will allow them to complete our knowledge of the characteristics of the Macasty formation and determine the best locations for the oil drilling planned for 2016. Five wells were drilled and core last year. The drill locations are shown on this map.



http://hydrocarbures-anticosti.com/en

Other Québec Information and Links

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

APGQ/QOGA Energy Inc. with annual Québec Shale Conferences.

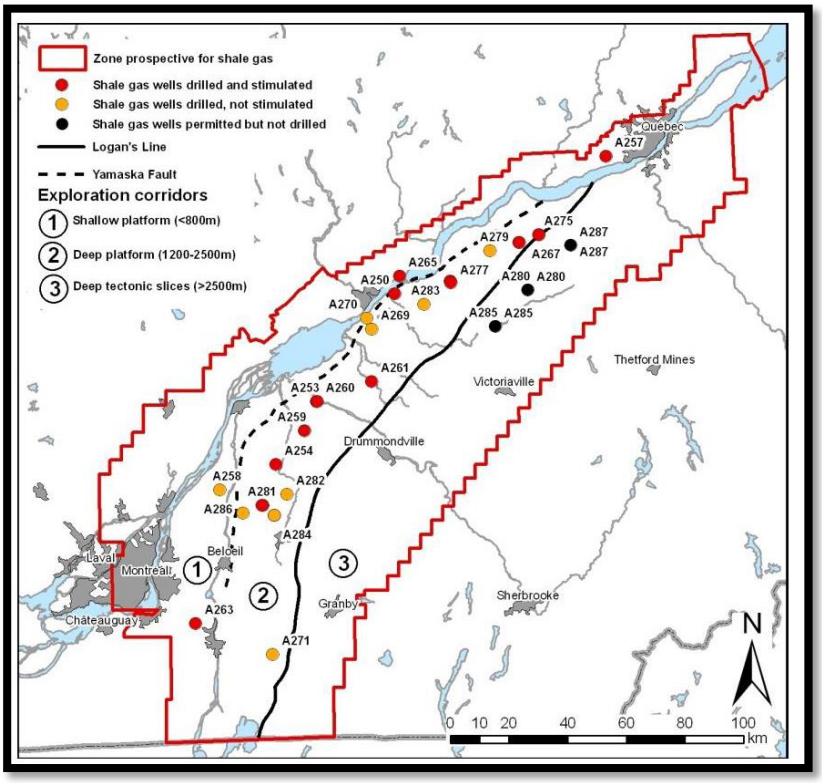
http://www.apgq-qoga.com/en/

http://www.apgq-qoga.com/en/conference-2015-2/

7th Annual conference Le Centre Sheraton Montréal on November 8 and 9, 2015.Nov 8-9 2015

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

St. Lawrence Lowlands, Québec: Shale Gas Area (Séjourné et al 2013)



NEW BRUNSWICK

Lower Mississippian Fredrick Brook Shale

Moncton Basin

Update on Hydraulic Fracturing

The New Brunswick government, Dec 2014, is introducing a moratorium on hydraulic fracturing that says won't be lifted until five conditions are met. Those conditions include a process to consult with First Nations, a plan for waste water disposal and credible information about the impacts fracking has on health, water and the environment**.** This was voted on in in March 2015 to prohibit fracking committing to study the controversial method of extracting oil and gas for one year before reconsidering the ban in 2016.

The Play History

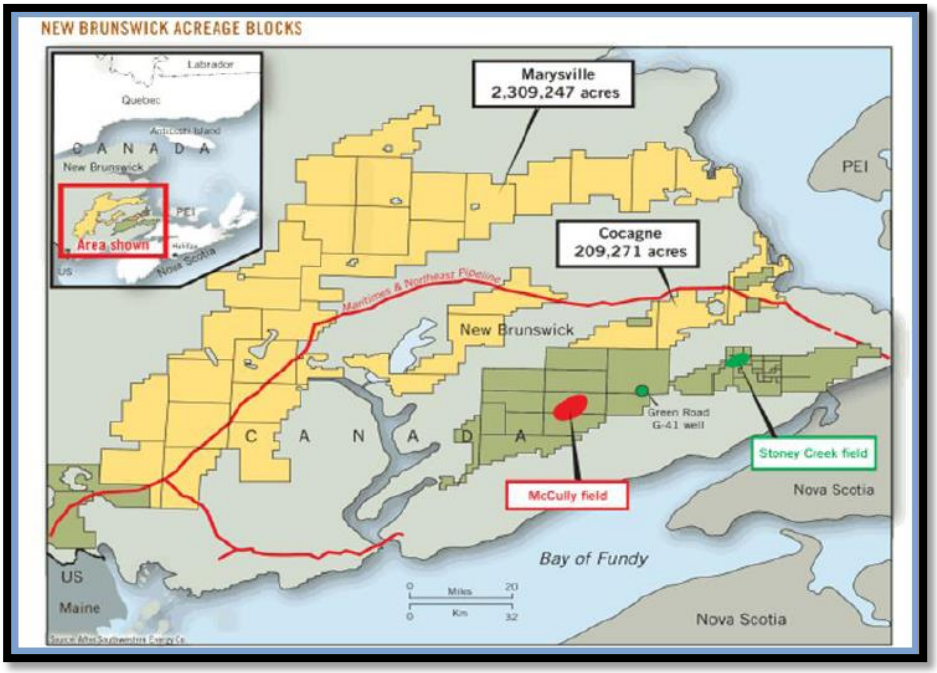
The Lower Mississippian Fredrick Brook Shale in the Moncton Basin had been the focus of thermogenic gas exploration in this province. The Green Road G-41 well was drilled by Corridor Resources in November, 2009 and tested in two zones in the Fredrick Brook, after fracking with propane. The lower black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

candidates. Corridor plans to evaluate these intervals with logs and sidewall cores in order to select the intervals for future fracture stimulation. The Will DeMille O-59 well is located north of Elgin, New Brunswick.

Contact Exploration and PetroWorth Resources were 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 unconventional resources of the Mississippian Horton Group. The company has completed airborne magnetic and gravity acquisition and is in the second phase of surface geochemical sampling and the acquisition phase of approximately 250 miles of 2-D data. Interpretation of the data is underway. $10.7 million was invested in 2010 with $14.2 million investment planned for 2011and then $14.2 million in 2012 with possible well(s).They finished their seismic program in Dec 2013. Four wells are proposed for drilling and the necessary documents have been filed.

https://www.swnnb.ca/



Other New Brunswick Information and Links

"Frederick Brook Shale spurs Canadian exploration," by Susan Eaton *AAPG Explorer*, August 2010, p.6-10.

http://www.aapg.org/explorer/2010/08aug/fredrick0810.cfm

New Brunswick Natural Resources, Minerals and Petroleum is the regulator for this province.

http://www.gnb.ca/0078/minerals/index-e.aspx

http://www.gnb.ca/0078/minerals/GSB_Hydrocarbon_Basin_Analysis-e.aspx#Objective

Shale Gas Website
http://www2.gnb.ca/content/gnb/en/corporate/promo/natural_gas_from_shale.html

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

NOVA SCOTIA

Upper Devonian/Lower Mississippian Horton Bluff

Kennetcook Basin - Update on Fracking

The Government has had a long history of reviewing the hydraulic fracturing starting in the spring of 2011 when an internal committee of officials from the Departments of Energy and Environment examined the environmental issues associated with hydraulic fracturing in shale gas formations. Recommendations were made for additional reviews.

The Nova Scotia Department of Energy commissioned the Verschuren Centre for Sustainability in Energy and the Environment at Cape Breton University on August 28, 2013 to conduct an independent review and public engagement process to explore the social, economic, environmental, and health implications of hydraulic fracturing practices and their associated wastewater streams. Dr. David Wheeler, President and Vice-Chancellor of Cape Breton University convened and chaired the 10 person Expert Panel on Hydraulic Fracturing and made the recommendations is a report dated 28th August 2014. The major conclusion of the Wheeler panel is that Nova Scotians are not yet ready for high volume hydraulic fracturing as part of onshore shale development. Therefore Nova Scotia moved ahead with legislation (Nov 2014) but the proposed law also includes an exemption that would allow fracking for testing and research purposes.

The Play History

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

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

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

The Nova Scotia Department of Energy (NSDOE), worked closely with industry, has undertaken the task of trying to understand the resource potential. GIP or "size of the prize" is determined by the shale's gas generating potential, the mineralogy which may dictate the fracking techniques and lead into the engineering solutions that need to be achieved through the drilling and piloting phase to reach commercial producabilty.

The energy trader who co-founded Galveston LNG Inc. and later sold the Kitimat LNG scheme to Apache Canada and EOG Resources for roughly $300 million is back with a new plan to export natural gas from Canada's east coast. Alfred Sorensen said today that his new company, Pieridae Energy Canada, plans to build an export terminal at Goldboro, Nova Scotia. It is contemplated that the gas source come from the Marcellus, New Brunswick? and offshore Nova Scotia. It has been issued long-term licenses (Aug 2015) by the National Energy Board of Canada to import natural gas from the USA and to export liquefied natural gas (LNG) from Canada.

http://pieridaeenergy.com/

http://www.albertaoilmagazine.com/2012/10/pieridae-energy-proposes-east-coast-lng-facility/

The Goldboro LNG Facility is to include a gas liquefaction plant and facilities for the storage and export of LNG, including a marine jetty for off-loading, and upon completion, is expected to ship approximately five million metric tons of LNG per year and have on-site storage capacity of 420,000 cubic metres of LNG. The Goldboro LNG Facility is to be located adjacent to the Maritimes & Northeast Pipeline, a 1,400-kilometre transmission pipeline system built to transport natural gas between Nova Scotia, Atlantic Canada and the North eastern United States.

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

NEWFOUNDLAND

Ordovician Green Point Shale - Western Newfoundland

The Cambro-Ordovician Green Point Formation is the focus of exploration activity for oil bearing shale in the western parts of the province. This Green Point interval has been studied in outcrop by the Geological Survey of Canada and is summarized in Hamblin (2006). Oil seeps have been documented along the entire coastline and some oil production from as early as the 1900's have been recorded. A well drilled in 2008 from the onshore to the near offshore by Shoal Point Energy and partners encountered about 500 to 2000 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 was undertaken by re-entry of the previous well bore, sidetracking and testing. These plans were unsuccessful and discontinued because of severe formation damage. Some of acreage has been relinquished but there are still two licences left with about approximately 150,000 acres of land. This is an offshore block enclosed, for the most part, by land with onshore to offshore drilling sites. The target package is a tectonically thickened and naturally fractured, interbedded black shales, siltstones and carbonates in excess of 2000 metres thick.

These projects are delayed since the government announced a study of the future of fracking.

http://www.releases.gov.nl.ca/releases/2013/nr/1104n06.htm
http://www.nr.gov.nl.ca/nr/energy/index.html#3

An independent Panel was appointed by the Minister of Natural Resources, Government of Newfoundland and Labrador, in October 2014 to conduct a public review of the socio-economic and environmental implications of hydraulic fracturing in Western Newfoundland. The mandate of the Panel is also to make recommendations on whether or not hydraulic fracturing should be undertaken in Western Newfoundland.

http://nlhfrp.ca/

The Newfoundland Department of Natural Resources is the regulator for the onshore portion of the province.

http://www.nr.gov.nl.ca/mines&en/oil/

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

This is the latest publication by the DNR on the Shale Oil Potential of the Anticosti Basin.

http://www.internationalpavilion.com/NAPE%202012%20Presentations/J%202.48-3.00%20Wednesday%20Newfoundland%20and%20Labrador.pdf

The Canada-Newfoundland Labrador Offshore Board is the regulator for the offshore portion.

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

TERRITORIES - NORTHWEST TERRITORIES

The Northwest Territories (NWT) has vast undeveloped oil and gas reserves. It is estimated that the NWT could hold as much as 37 percent of Canada's marketable light crude oil resources and 35 percent of its marketable natural gas resources**.**

The Department of Industry, Tourism and Investment (ITI) is responsible for the administration of onshore oil and gas interests in the Northwest Territories, including the Inuvialuit Settlement Region. Interests issued in the offshore are the responsibility of Aboriginal Affairs and Northern Development Canada. This study was commissioned jointed by the National Energy Board and NWT Geological Survey.

https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/rprt/2015shlnt/index-eng.html

The National Energy Board (NEB) had regulatory responsibilities for oil and gas exploration and production activities, including the drilling, completion, hydraulic fracturing and formation flow testing of, and production from onshore unconventional reservoirs under the Canada Oil and Gas Operations Act (COGOA) and its regulations. who is responsible for these lands. They completed the following guidelines. Filing Requirements for Onshore Drilling Operations Involving Hydraulic Fracturing September 2013.

https://www.neb-one.gc.ca/bts/ctrg/gnthr/flrqnshrdrllprtn/flrqnshrdrllprtn-eng.pdf

The GNWT is currently in the process of developing an NWT Oil and Gas Strategy. Part of that Strategy is considering improvements to the regulatory regime to ensure that any future development employing hydraulic fracturing will be done safely to assure protection of our environment and the health and safety of our people.

http://www.iti.gov.nt.ca/news/discussions-hydraulic-fracturing-regulations-continue-18th-legislative-assembly

2014–2015 Call for Bids in the Central Mackenzie Valley Date of Launch: January 30, 2015 and closing date: June 2, 2015 – no bids were received. This area is far to the north west of the Canol Shale area around Norman Wells.

http://www.iti.gov.nt.ca/infopage/central-mackenzie-valley-call-bids-2014-2015

Devonian Canol Shale

Recent News

With the recent decline in oil prices, most companies have put their exploration plans for the Northwest Territories (NWT) on hold.

The National Energy Board of Canada completed a study of volume of oil-in-place for the Bluefish Shale and the Canol Shale of the Northwest Territories' Mackenzie Plain has been evaluated for the first time by the National Energy Board and the Northwest Territories Geological Survey. The thick and geographically extensive Canol Shale is expected to contain 145 billion barrels of oil-in-place. The much thinner Bluefish Shale is expected to contain 46 billion barrels of oil-in-place.

The amount of marketable (i.e., recoverable) oil was not estimated because well-test results are not yet publicly available and there is still uncertainty about whether these shales are capable of production. However, if only one percent of the in-place resource could be recovered from the Canol Shale, it would represent a marketable resource of 1.45 billion barrels. Based on the limited geological data available, the analysis assumes that both shales are saturated with oil throughout the study area.

https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/rprt/2015shlnt/index-eng.html

Historical Background

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

Canada's Northern Oil & Gas Directorate held lease sales in 2011 and 2012 where industry has committed $628 million in work commitments on 13 exploration licenses in the central Mackenzie region. It is speculated the Canol Shale play was the main target.

The Canol shale formation could be as big as the prolific Bakken light oil play. Initial estimates peg the Canol play at two to three billion barrels of recoverable crude in a region which has seen drilling activity for almost a century but has yet to reap substantial economic benefit because of its remote and challenging terrain. The plan is for companies such as Imperial Oil, Shell Canada and MGM Energy (one well), ConocoPhillips (two wells), Husky Energy (two wells) and International Frontier to continue activity to prove up the resource and eventually produce crude for southern market.

http://m.theglobeandmail.com/globe-investor/husky-prepares-an-arctic-expedition/article4179898/?service=mobile

In the 2012/2013 winter drilling season ConocoPhillips drilled two horizontal-fracture-stimulated wells on EL-470, the wells were the first horizontal-fracture-stimulated wells that evaluated the Canol Shale, both wells are on confidential status.

MGM (Now Paramount) in partnership with Shell, who farmed in, were the first to announce the results of drilling and hydraulic fracking this new play. Their vertical well into the Canol shale resulting in the recovery of approximately 140 barrel of fluid consisting of frack fluid, crude oil and natural gas. Their discovery was awarded a large Significant Discovery Area this summer.

According to MGM, the Canol/Hare Indian shale is 30-170 metres thick at a depth of 1,000-2,500 metres. In addition, the Bluefish Shale is 15-25 metres thick at a depth of 1,000-2,700 metres. Both are highly brittle, which is a key attribute for successful fracturing. There independent reserve estimate on four exploration licenses are about 11 Billion Barrels oil in place, mean. Drilling is restricted to the months of January to March.

Husky Energy has withdrawn its application to horizontally drill and frack up to four wells in the Sahtu region of the N.W.T. ConocoPhillips drilled and fracked their two horizontal wells in the Canol shale. They were successful and are applying for a Significant Discovery License (SDL). No results of the publication of this report. ConocoPhillips says it doesn't plan to do any more exploration work on its parcel in the N.W.T.'s Canol shale oil play for the foreseeable future.

http://www.cbc.ca/news/canada/north/conocophillips-seeks-declaration-of-significant-n-w-t-discovery-1.2998597

The nearby Norman Wells oil field discovered in the 1920s, has been in decline for a decade and the Enbridge Pipeline to Alberta is running at 33% capacity at 40,000 barrels of oil per day.

See Hadlari and Issler and Pyle and Gal in References.

http://www.ihs.com/products/oil-gas-information/source-newsletter/international/jan2012/canadian-alaskan-exploration.aspx

Geoscience Office

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

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

YUKON

The Yukon Geological Survey has conducting studies to determine the potential of shale gas in the territory. Shale gas has not been explored for or produced in Yukon; however, future oil and gas projects will most likely consider shale gas reservoirs as potential targets. Shale is likely found in all of Yukon's oil and gas basins. Whether or not the shale formations contain natural gas in sufficient quantity to produce has yet to be determined. The Yukon Geological Survey conducted a scoping study to identify the presence of shale gas and other unconventional oil and gas resources in the Yukon. The results of this study were published in 2012. http://ygsftp.gov.yk.ca/publications/miscellaneous/Reports/YGS_MR-7.pdf

Northern Cross Yukon acquired 15 exploration permits in Northern Yukon. There will be 4 wells drilled in the far north for conventional targets as well as consideration of the shale potential in the Devonian.

In the south, in the Liard Basin, which extends into BC, EFLO Energy and partners are planning to exploit the Devonian/Mississippian shales near the Kotaneelee conventional field. This resource has the potential of 500 to 100 BCF of conventional gas and 7.2 to 13 TCF of shale gas. A sales gas pipeline exists to Ft. Nelson.

The Yukon government has established a committee to review hydraulic fracturing before it is permitted.

http://www.legassembly.gov.yk.ca/rbhf.html

The report was completed in Jan 2015 with comments that a clear majority of First Nation governments and Yukoners who participated in the Committee's activities indicated their opposition to hydraulic fracturing but they came up with a list of 19 recommendations.

The latest news suggests that the territorial government plans to pave the way for fracking in the Liard basin in southeast Yukon, saying it will focus on the area "for further research and possible shale development."

http://www.emr.gov.yk.ca/oilandgas/hydraulic-fracturing.html

Yukon Energy, Mines and Resources

http://www.geology.gov.yk.ca/

http://www.emr.gov.yk.ca/oilandgas/

NUNAVUT

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

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

Additional Information

National Energy Board of Canada

http://www.neb-one.gc.ca/clf-nsi/rcmmn/hm-eng.html

Geological Survey of Canada

http://www.nrcan.gc.ca/earth-sciences/science/geology/gsc/17100

Canadian Association of Oil Producers

http://www.capp.ca/Pages/default.aspx

Societies, Conferences and Courses

Canadian Society for Unconventional Gas (CSUR)

http://www.csur.com/

Note that they have technical luncheons for members.

http://www.csur.com/csur-technical-luncheon-series-presentations

http://www.csur.com/events/technical-conference

CSUR now has Canadian Play maps at this location.

http://www.csur.com/canadian-discovery-play-maps

Canadian Society of Petroleum Geologists (CSPG)

Note the CSPG has technical luncheons throughout the year.

http://www.cspg.org/

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CHINA SHALE GAS AND SHALE OIL

Shu Jiang, University of Utah, Energy & Geoscience Institute (EGI)

The shales spanning from Pre-Cambrain Sinian (a period right before Cambrian) to Quaternary are wildely distributed in China. The Pre-Cambrian to Upper Paleozoic organic rich marine and transitional shales with maturity in gas window and shallow Quaternary shales have shale gas potentials and Mesozoic to Cenozoic organic rich shales with maturity in oil window have shale oil potentials (Fig.1, Fig. 2). 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 (billion cubic meter or 1050 TCF). In 2011, the US Energy Information Administration (EIA) assessed that China could have 1275 trillion cubic feet (TCF) technically recoverable shale gas, in March 2012, China Ministry of Land and Resources announced China had 25.08 trillion cubic meters (886 TCF) of recoverable onshore shale gas reserve. Recently, EIA reduced China recoverable shale gas reserve to 1115 TCF in June 2013 and gave a number of 32 Billion Barrel recoverable shale oil for China. Either number indicates China's shale resource is comparable with US's updated 665 TCF recoverable shale gas and 58 billion barrels of shale oil resource. China has been emulating the successful U.S. production experiences and models in order to power its economy and reduce greenhouse gas emissions.

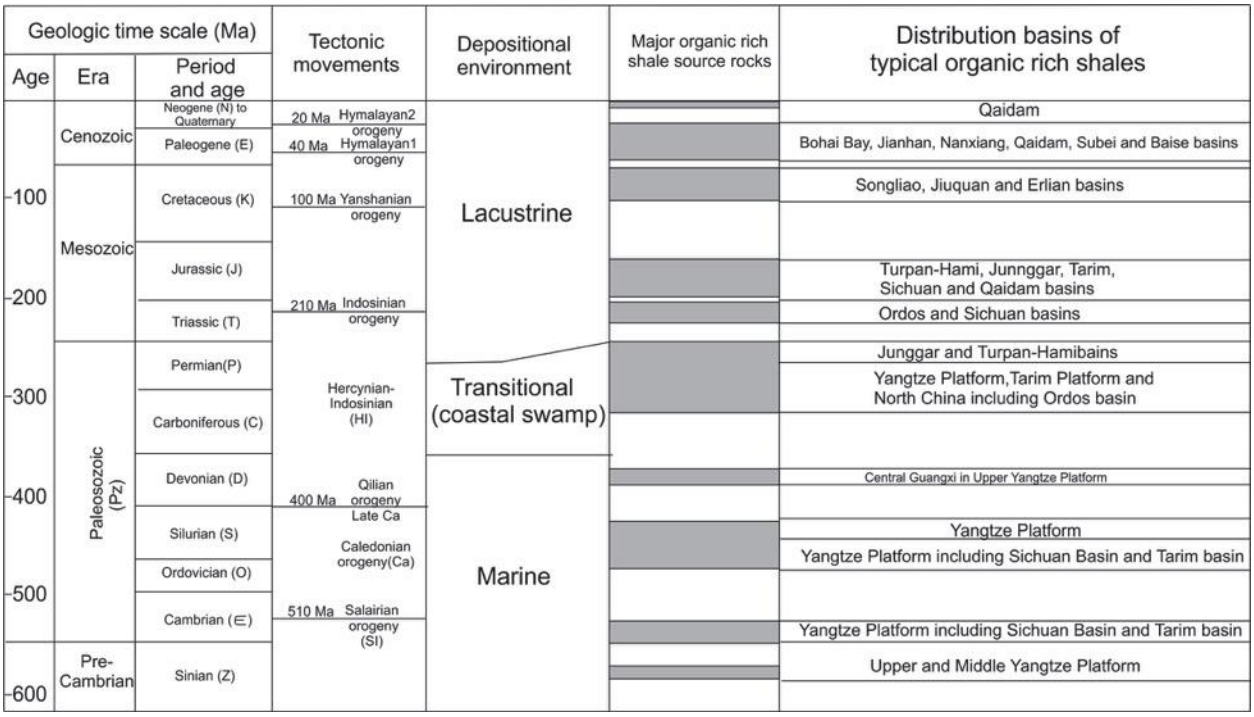


Fig. 1 Geologic history and organic rich shale development in China

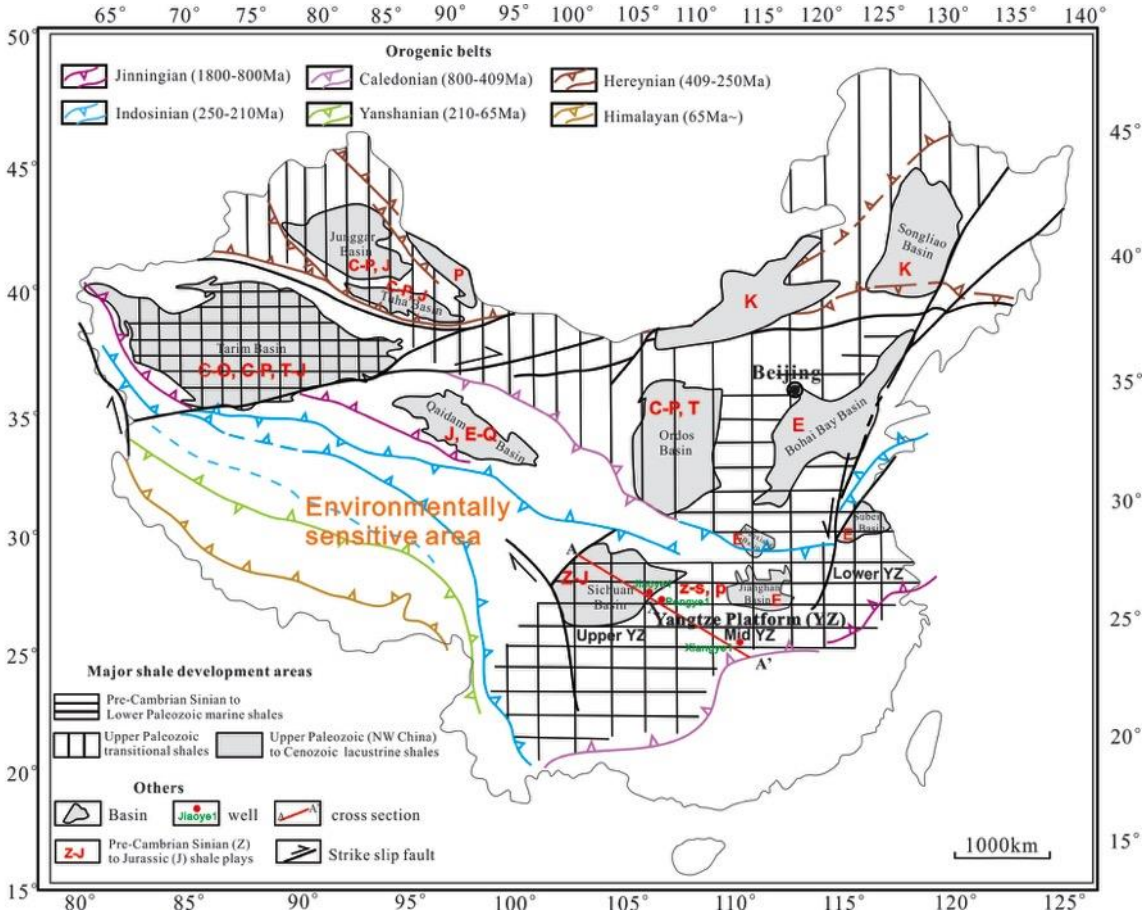


Fig. 2: The distribution of organic rich shales in China. Z=Pre-Cambrian Sinian; ∈=Cambrian; O=Ordovician; S=Silurian; C=Carboniferous; P=Permian; T=Triassic;J=Jurassic; K=Cretaceous; E=Paleogene. Q=Quaternary

For US producing shales, they were deposited marine depositional setting. But for hydrocarbon related shales in China were formed in diverse paleo-environments. The Pre-Cambrian to Lower Paleozoic shales distributed all over China were deposited in marine setting. The Upper Paleozoic (Carboniferous to Permian) shales mainly in North China and NW China were deposited in transitional (coastal swamp associated with coal) setting. The Meso-Cenozoic sporadically distributed shales were deposited in lacustrine setting (Fig.2). The typical marine shale, transitional shale and lacustrine shale can be represented by Lower Paleozoic Sichuan Basin, Carboniferous to Permian Ordos Basin and Cenozoic Bohai Bay Basin respectively (Fig.3). The Table 1 summarizes the depositional settings and distribution in time and space for the potential gas and oil shales in China.

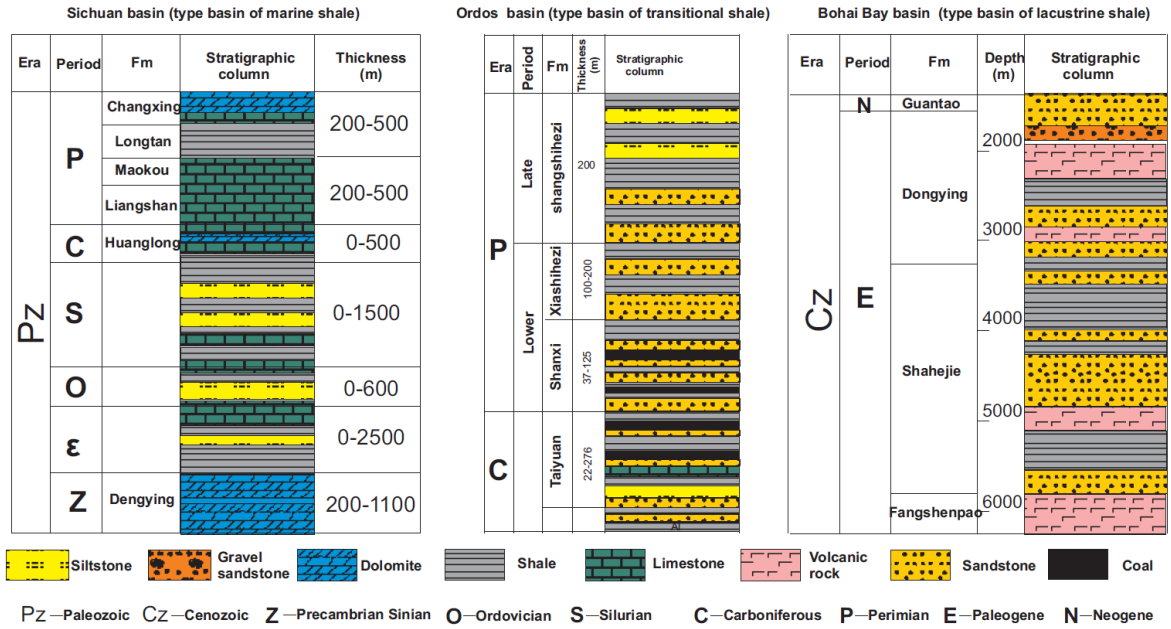


Fig.3 Three kinds of potential shales (marine, lacustrine and transitional/coastal setting) and their type basins

Table 1 Depositional setting and distribution in time and space of potential China shales

Depositional setting	Age and Formation		Distribution area
Lacustrine	Cenozoic	Neogene	Qaidam Basin
		Paleogene	Bohai Bay Basin, Qaidam Basin
	Mesozoic	Cretaceous	Songliao Basin
		Jurassic	Turpan-Hami, Junggar, Tarim, Qaidam, Sichuan Basin
		Triassic	Ordos Basin, Sichuan Basin
	Paleozoic	Late Permian	Junggar, Turpan-Hami
Transitional (coastal setting associated with coal)	Paleozoic	Late Permian (Longtan Fm)	Yangtze Platform including Sichuan in Upper Yangtze
		Early Permian (Taiyuan, Shanxi Fm)	North China
		Late Carboniferous (Benxi Fm)	North China
Marine	Paleozoic	Early Silurian (Longmaxi Fm)	Yangtze Platform including Sichuan in Upper Yangtze
		Late Ordovician (Wufeng Fm)	Yangtze Platform including Sichuan in Upper Yangtze, Tarim Basin
		Early Cambrian (e.g. Qiongzhusi Fm)	Yangtze Platform, Tarim Basin
	Pre-Cambrian	Sinian (e.g. Doushantuo Fm)	Upper and Middle Yangtze Platform

China has put lots of effort investigating shale gas and shale oil for 6 years after the first industrial shale gas flow from Ordovician Wufeng-Lower Silurian Longmaxi shale from Wei201 well in Southwest Sichuan Basin. So far, 2D seismic data covering 9000 km^2 and 3D seismic data covering 800 km^2 were acquired, and 800 shale gas wells (including shallow parameter wells behind outcrop) targeting marine, lacustrine and transitional (coastal swamp setting associated with coal) shales were drilled so far by the PetroChina, Sinopec, CNOOC, Yanchang Petroleum, other state or private companies who recently got shale blocks, Ministry of Land and Resources and foreign partners of Chinese state oil companies. The exploration activities have been mainly focused in Sichuan Basin, Yangtze Platform outside Sichuan Basin, Ordos Basin, Bohai Bay Basin and Nanxiang Basin (Fig.4). Recently, the Junggar basin has also become target basin for shale oil associated with tight dolomite oil play. One recent breakthrough is that China and Argentina becomes only two countries outside of North America that has reported commercially viable production of shale gas and tight/shale oil, although the volumes contribute less than 2% of the total natural gas production in China. The successful development evidence in Sichuan Basin especially shale gas production from Silurian Longmaxi marine shale in Fuling area recently makes the China's 2015 output reach 4.47 bcm. Recently, China has nearly tripled the size of proven reserves to 380.6 bcm in its Fuling area according to Sinopec and Ministry of Land and Resources. By the end of October 2016, a total of 233 wells at the Jiaoshiba block have been in production. A well in Fuling shale gas field in E Chongqiong was reported to produce 547,000 cubic meters/day. In late 2016, Sinopec-Huadong tested the Jiaoye195-5HF fractured horizontal well and got commercial 220,000 m^3/day, which proves the Nanchuan area located in the southwest of current commercially producing Fuling shale gas field would be next commercial shale gas production area in the near future. In the Dingshan area to the southwest of Nanchuan area, Sinopec Exploration Company tested industrial shale gas flow from two wells. These indicate that Sinopec has huge potential to expand the commercial shale gas production in the southeast Sichuan Basin based on the step-out exploration results from Fuling to Nanchuan and Dinghan areas. As examined and approved by China's Ministry of Land and Resources recently, CNPC has added 207.87 km2 of new shale gas bearing areas in the well blocks of Wei-202, Ning-201 and YS108 in the Sichuan basin. The areas have been added with proven original gas in place of 163.53 Bcm and technically recoverable reserves of 40.88 Bcm. All three well blocks are located in the national shale gas demonstration zone in the Sichuan basin. By 2016, CNPC's 137 wells had produced 3.7 billion cubic meters shale gas. The rate from well Yang201-H2 in Luzhu, Sichuan was reported to produce at 430,000 cubic meters per day. By 2016, the average daily shale gas production per well of CNPC's shale gas wells produce at rate of 176,000 m^3/day. Both Sinopec and CNPC's shale gas discoveries have encouraged Beijing government and still draw interests of international oil companies e.g. BP even the current gas price is low. For lacustrine shale gas, Yanchang Petroleum made breakthrough in Xiasiwan in Ordos Basin, 59 wells including 6 horizontal wells were drilled to target the Upper Triassic lacustrine Yanchang7 shale. The successful wells including Liuping177 and Yun2 wells. China has commercially produced 8.5 billion cubic meters in 2016, increasing by 90% from 4.47 billion cubic meters in 2015 from pilot production areas mainly in Fuling, Changning-Zhaotong, Weiyuan, and Fushun-Yongchuan (Fig. 5). The China vast shale resources are expected to be produced on a larger scale and even from

untapped areas that were considered no exploration potential in the past due to tectonic disruptions. Recently, China Geologic survey made the breakthrough in the tectonically active area outside Sichuan Basin in the Anchang area in Qianbei, Guizhou Province. The Anye1 well was initially tested to produce gas at maximum rate of 420.1X10^3 cubic meters/day from Silurian limestone and shale and Permian limestone. For the tight oil, PetroChina's Changqing Oilfield recently discoveried of the country's largest tight oil field-Xinanbei field with100 million tonnes proven geological reserves. For lacustrine shales, PetroChina and Sinopec recently speeded up lacustrine shale oil exploration in Junggar and Sichuan Basin, e.g. Sinopec drilled Shiping 2-1H horizontal wells targeting Jurassic lacustrine shale and got 33.79 tons condensate production after 5 stages fracturing in 864 m lateral.

Fig.4 the shale exploration activities in China

Fig. 5 Current shale gas exploration and production in China

(Dazhong Dong, 2016)

Geological investigation and exploration show that most potential shales in China had and still have high organic content and marine shales have high maturity for gas generation and lacustrine (lake) shales have low maturity for oil generation. Characteristics of high organic matter content, high maturity, high brittle minerals (Fig.6) and high intra-organic nano-porosity (Fig.7) make China marine shales same to US shales and potentially producible. The drilled shale gas wells targeting marine shale in Sichuan Basin show the similar favorable shale properties e.g. high TOC, high brittleness, etc. as US producing marine shales (Fig.8). Generally, China lacustrine shales have high clay content than marine shales (Fig.6), this is why many experts think it is much more difficult to frac the lacustrine shale. Since lacustrine basins contribute 90% oil production in China and they are expected to pay a more significant role in shale oil production, we need new technologies to develop the gas or oil trapped in lacustrine shales. Recently, the tight dolomite oil production from Permian source rock interval in Junggar Basin in NW China (Fig.9) and tight sand oil from Ordos Basin (Fig.10) in North China showed the potentials of lacustrine tight oil potential similar to Bakken shale oil which is mainly produced from middle Bakken dolomite equivalent tight reservoirs. But the oil production from lacustrine shale is still in early stage. In the future, the shale gas and shale oil and tight sand and tight carbonate reservoirs within the organic rich shale could consist of hybrid reservoirs e.g. shale oil and tight sand oil in Triassic source rock interval in Ordos Basin (Fig.10) and shale gas and tight gas production from Jurassic Dongyuemiao lacustrine source rock interval (Fig. 11).

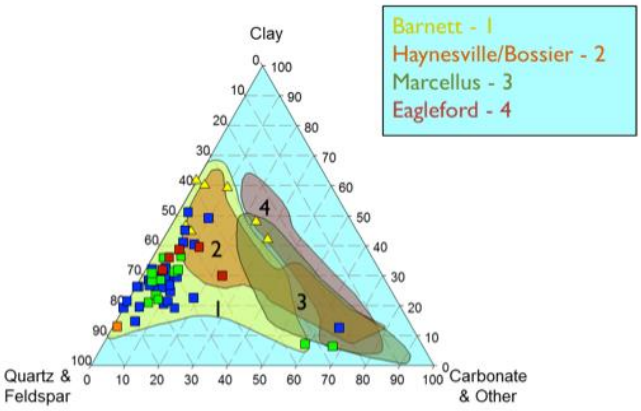


Fig.6 Ternary diagram for mineralogy of marine shale (square legend) and lacustrine shale (triangle legend) in China and its comparison with mineralogy of typical US shales.

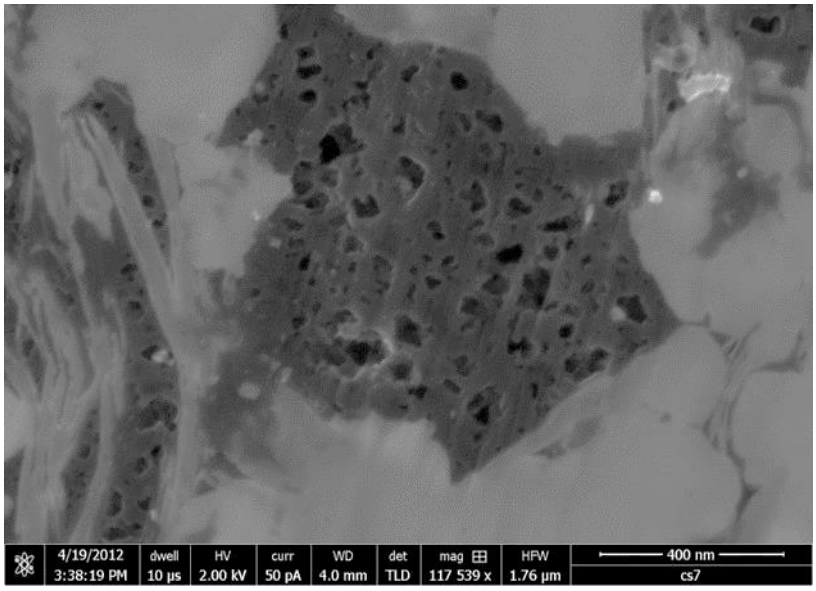


Fig.7 SEM of ion polished sample showing intra-organic nano-pores of a marine shale Sichuan Basin, China

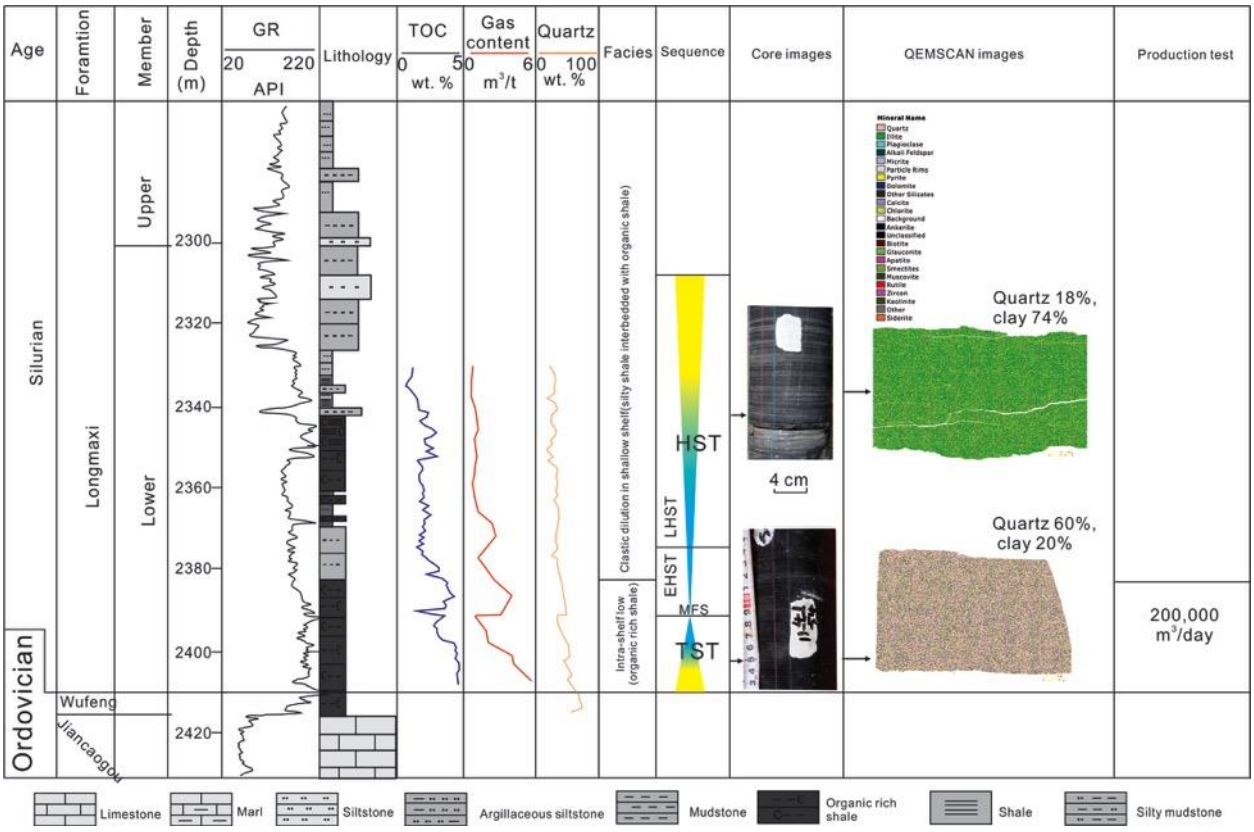
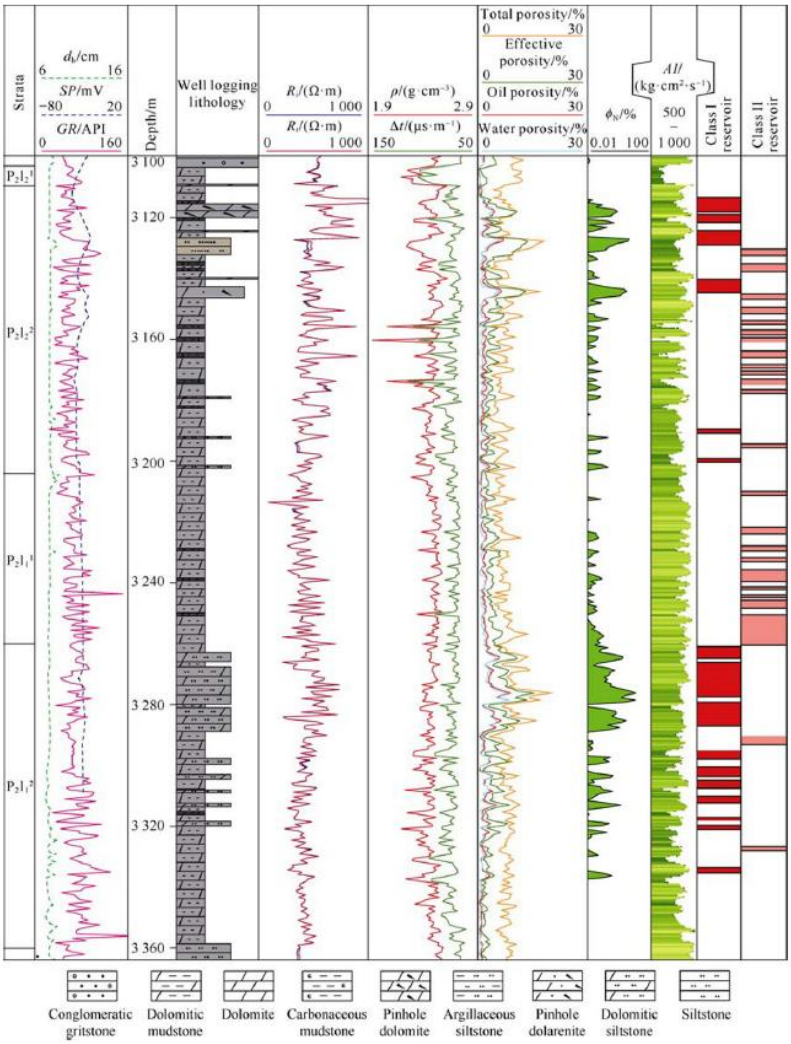


Fig.8 Typical shale gas well in Sichuan Basin for marine shale gas



Comprehensive well logging evaluation chart of the Lucaogou Formation reservoir in the Jimsar Sag. d_h—hole diameter; ontaneous potential; GR—gamma ray; R_i—resistivity of intrusion zone; R_t—formation resistivity; ρ—density; Δt—interval tran- ϕ_N—neutron porosity; AI—acoustic impedance.

Fig.9 Tight dolomite oil from Permian source rock interval with shale oil show, Junggar Basin, NW China (L. Kuang, 2012)

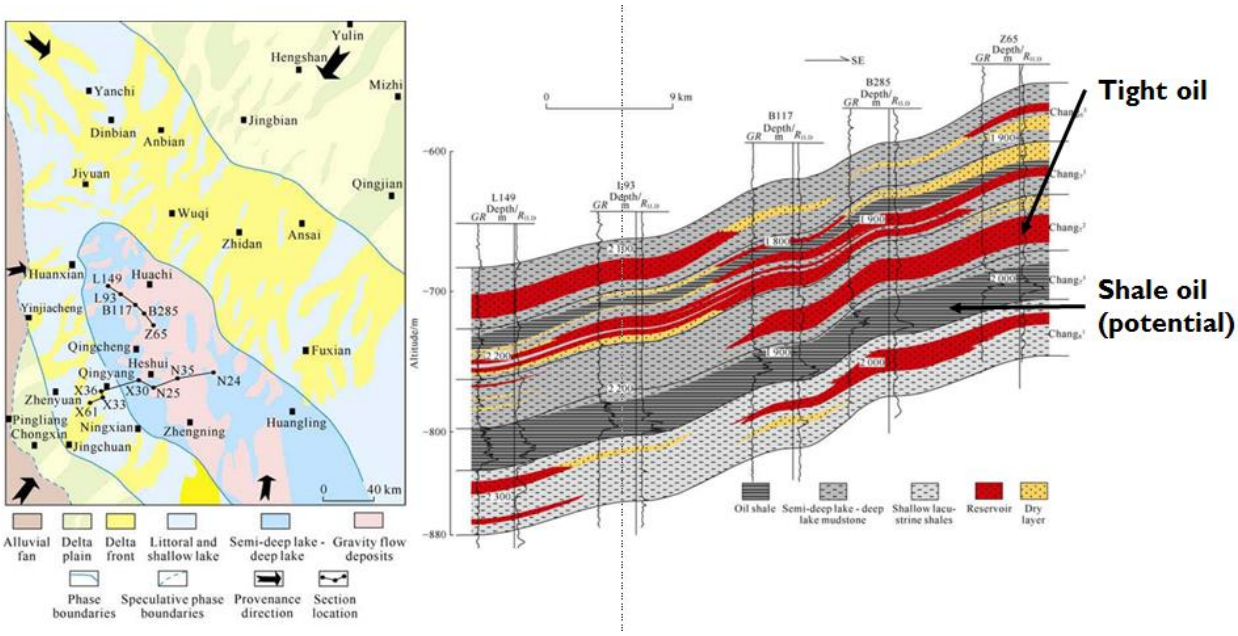


Fig. 10 Tight oil and potential shale oil of Triassic Yanchang Fm in Ordos Basin (modified from YAO Jingli, 2013

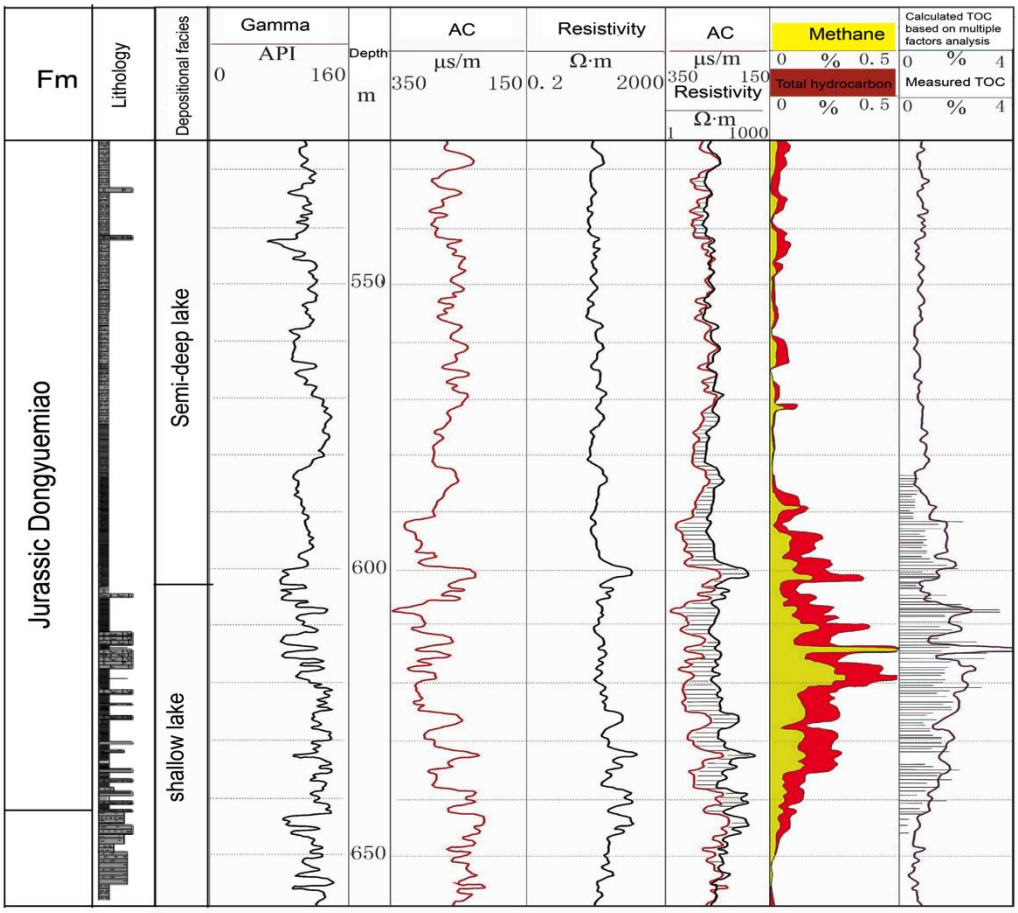


Fig.11A well in east Sichuan Basin targeting Jurassic Dongyuexiao lacustrine Fm. The gas produces from both shale and tight carbonate intervals.

What made shale gas or shale oil work is hydraulic fracturing or fracturing, but every shale in the world is different, the shale depositional settings and geologic history made each shale with unique mechanical property. Shale gas and shale oil are produced from marine shales, fine-grained chalks and dolomite interbeded in source rock intervals in US basins. These basins have relatively simple tectonic settings than China. Even promising marine shales in China are similar to brittle Barnett shale in US regarding mineralogy, the complex tectonic setting, much more complex diagenetic history and harsh ground conditions make shale gas extracting in China more challenging than that in US. In some areas in China, the shale resources are either located in the subsurface below the rugged mountain or desert, also, the historical multi-stages of strong tectonic compression, extension in China cause shales in China have different stress fields than those in US, e.g. the maximum principal stress is horizontal in some areas e.g. basins in front of collision zone of Tibet Plateau and the maximum principal stress is vertical in US, this is why the fracing experiences in US may not work very well in China. We need investigate more about the geology, geomechanics and hydraulic fracturing design for unique China shales.

Since shale gas exploration and production is technically challenging and China basins have complex tectonic activities and different properties for shales, China has been collaborating with international oil firms and service companies to achieve the ambitious shale gas production plan. Chinese state-owned oil, coal and power energy companies and privately-owned junior

companies with no energy experience have tied up with foreign oil companies such as Shell, ExxonMobil, Chevron, ConocoPhillips, Eni, BP, Total, Statoil, Schlumberger, etc. to gain hydraulic fracturing technology in shales. Even though the recent 2nd round bidding blocks located at the margin or outside conventional oil and gas producing basins disappointed many companies. With the speeding and recent good exploration result of Paleozoic marine shale gas exploration and Meso-Cenozoic lacustrine shale oil exploration and very exciting test result in Sichuan Basin, Shell's production-sharing contract with CNPC (parent company of PetroChina) was approved by Chinese government and Hess signed PSC with CNPC in Langma shale oil block in NW China recently, which inspired many companies in the past. But the recent evaluation shows mixed results in Shell-CNPC's joint blocks e.g. Funshun-Yongchun block. Due to complex geology and challenging drilling and completion conditions in China, recent downturn of oil price and budget cut of many companies. Some companies are pulling out of China. ConocoPhillips has ended talkds with PetroChina on shale gas development in China after two-year study on the Neijiang-Dazu block in Sichuan Basin. But BP recently signed PSC with CNPC recently took over the Neijiang-Dazu block. PetroChina plans to drill 113 horizontal shale gas development wells in the next 2 years in Sichuan Basin. Sinopec has planned to drill more in SE Chongqing/E Sichuan Basin and NE Sichuan Basin due to recently commercial shale gas from both marine and lacustrine shales in Sichuan Basin. Based on these, the coming third shale gas bid round will be better than the first two.

The complex geologic setting and different geomechanics regime in China basins did challenge many international companies with successful US shale experiences to frack shales in China. The trial-and-error in the in pilot shale gas areas in Changning-Weiyuan in Sichuan, Fuling, Nanchuan and Dongshan in Chongqing, Yanchang block in Ordos has helped companies know better and better to frack shales in China. With limited participation from established global service companies such as Baker Hughes and Schlumberger, Sinopec's Jianghan oilfield has improved in key areas of fracturing and logging. At one well in Sichuan Basin, Sinopec-Jianghan did 22-stage fracturing at a depth of 1,500 meters and the test result showed commercial flow of shale gas. So far, the horizontal drilling and hydraulic fracturing of shales have been reported to generate large stimulated reservoir volume (SRV) (Fig.12). As Chinese companies gain experience and knowledge of producing from shale, the cost of shale gas drilling has declined. The cost of drilling a horizontal well in shale formations in the Sichuan Basin was reduced to $11million per well in 2015 from $15 million per well in 2013 (Fig. 13).

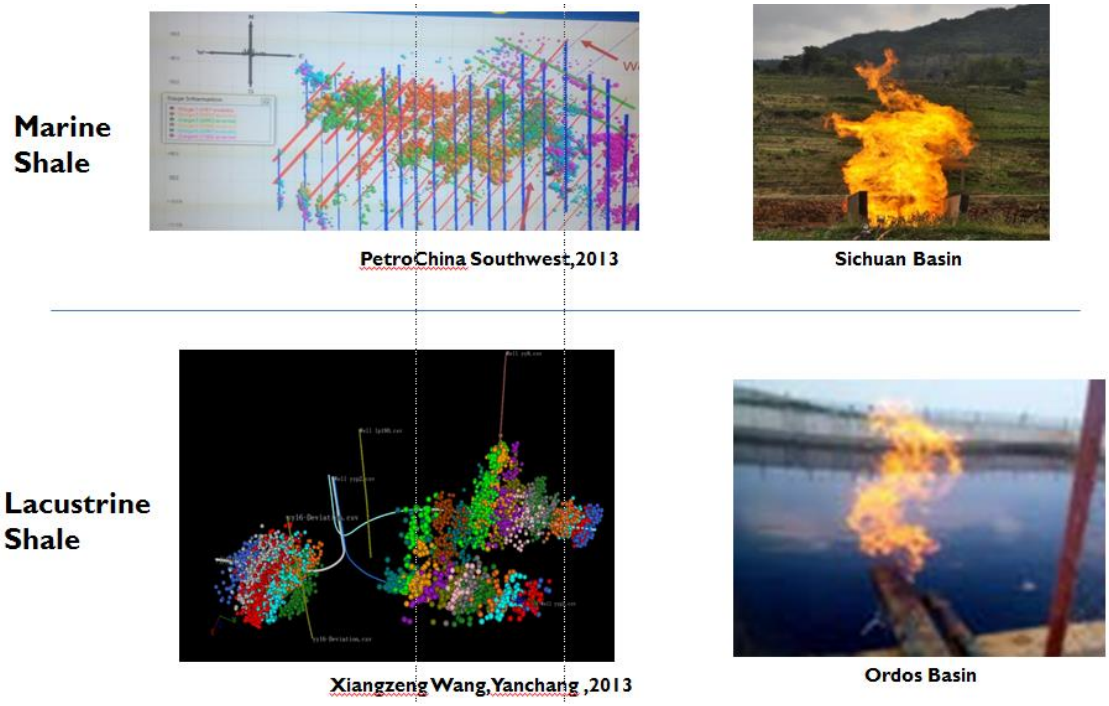


Fig. 12 Horizontal drilling and hydraulic fracturing for both marine and lacustrine shales in China

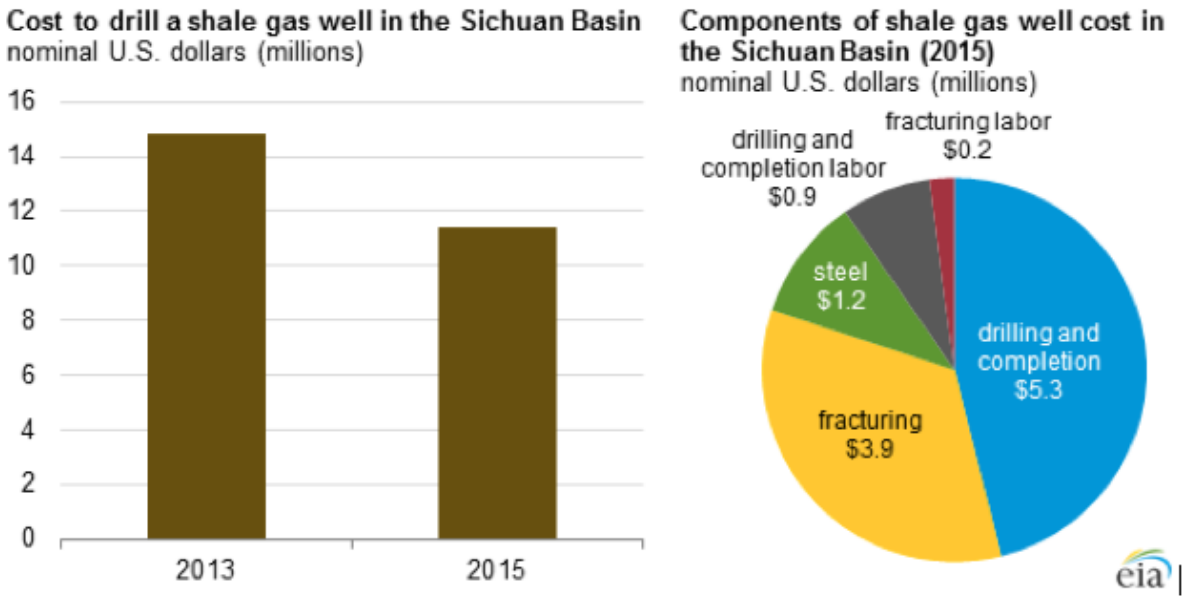


Fig. 13 Cost of shale gas well in Sichuan Basin in China (EIA, 2015)

At the same time, The China National Energy Administration **("NEA")** issued the Shale Gas Industry Policy **("Policy")** in late October 2013. The Policy recommends certain reforms to encourage more companies besides oil companies to get access to shale gas exploration and development in China. Also, the new policy gives subsidies and tax incentives to shale gas production companies. In 2012, to encourage the exploration of shale gas, the Chinese government established a four-year, $1.80 per million British thermal units subsidies program for any Chinese company reaching commercial production of shale gas. In mid-2015, these subsidies were extended to 2020, but at a lower rate. After two disappointing shale licencing rounds (in 2011 and 2012), China is working to identify prospective and investor-friendly blocks and adopt

better policies to attract potential investors, e.g. China is considering to extend shale gas and CBM subsidies for another 20 years until 2015.

In summary, China has huge potential for both shale gas and shale oil potential, even though the geological setting and geomechanics regime are more complex than US producing shales for hydraulic fracturing, with the learning curve for the lacustrine shale gas in Ordos Basin and shale oil in Nanxiang Basin in central China and tight/shale oil in Santanhu and Junngar Basin in Northwest China, and recent commercial shale gas production from marine in Sichuan Basin by PetroChina and Sinopec, technology advancement, decreases in the cost to drill shale gas wells, continued investment into domestic production and policy support for incentives and reforms from Chinese government. The proportion of shale gas has risen from 3.3% in 2015 to 6.2% in 2016.This indicates that China could meet the expectation of shale gas production of 30 billion cubic meters in 2020 based on current trend. EIA predicted in 2016 that China' shale gas was projected to account for more than 40% of the country's total natural gas production by 2040, which would make China the second-largest shale gas producer in the world after the United States.

SHALE GAS AND SHALE LIQUIDS PLAYS IN EUROPE

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Contents

1. Summary of the period April 2016 – November 2016

Europe remains relatively unexplored for shale gas and, especially, shale liquids. In total some 132 exploration and appraisal wells with a shale gas exploration component have been drilled, including horizontal legs from vertical wells. 36 of these wells are shallow gas tests drilled in Sweden, largely using mineral exploration equipment. Some 8 wells have been drilled to target shale liquids.

Significant shale gas exploration activity since April 2016 has been limited to Sweden where a production test well at the site of the Siljan Ring impact crater was spudded in July and flowed gas. It now appears, however, that the gas is free gas and not shale gas.

Opposition to hydraulic fracturing and shale oil and gas exploration at grassroots level in general remains strong. Public pressure has resulted in moratoria being placed on some or all aspects of shale gas exploration and production in Bulgaria, Czech Republic, France, Germany and Netherlands, plus certain administrative regions in Spain, Switzerland and the UK (Scotland; Wales; Northern Ireland). Proposed new environmental legislation led OMV to abandon its plans for shale gas exploration in Austria.

The geology, however, has not proved entirely favourable either. Interest in the exploration potential of Poland has diminished significantly since 2012, when 24 wells were drilled. Of 123 shale gas and shale liquid concessions awarded to date, 94 have been relinquished. Chevron, ConocoPhillips, ExxonMobil, Marathon, Talisman, Eni and Total have all withdrawn from Poland. Two awards were made in the period April to November 2016, both of them concessions which had previously been relinquished. Of the 29 valid shale gas and shale liquids concessions, 15 are operated by three Polish companies - PKN Orlen (7), LOTOS Petrobaltic (3 offshore; 1 onshore) and Polish state company PGNiG (4). The other significant concession holder is ShaleTech Energy, a 100% subsidiary of Luxembourg-registered Stena Investment, the international holding company of Swedish company Stena AB. ShaleTech holds 3 concessions with shale gas potential and 4 with shale liquids potential. In mid-October 2016 Reuters reported that both PKN Orlen and PGNiG have abandoned their shale gas projects.

The best combination of geology and effective regulatory regime appears to be in the United Kingdom, where the UK Conservative government elected in May 2015 has shown considerable support for the emerging shale gas industry. The perceived prospectivity of the UK is also indicated by company acquisitions and farm-ins to acreage with shale gas potential since May 2013 by Centrica, Total, GDF Suez, IGas, INEOS and Egdon Resources. Applications by Cuadrilla to drill and fracture shale gas exploration wells in the West Bowland Basin (Lancashire), by Third Energy to fracture test an existing vertical well in the Cleveland Basin and by IGas to explore the Gainsborough Trough (East Midlands) are at various stages of the planning and permitting process but have now largely been approved.

A review of *all* European activity prior to April 2016 can be found and downloaded here at:

https://www.academia.edu/24840178/Shale_Gas_and_Shale_Liquids_Plays_in_Europe_April_2016

2. Country Updates

France.

On 13th July 2011 the French government passed a law (Law 2011-835) that prohibited the exploration for, and production of, liquid or gaseous hydrocarbons by hydraulic fracturing. On March 2nd 2016, energy and environment minister Ségolène Royal informed the National Assembly that a ban on *all* non-conventional hydrocarbon developments would be included in a reform of the Mining Code. Royal is opposed to shale gas in all its forms. In May she said that she was seeking legal means to ban the import of LNG from the USA, which contains about 40% shale gas.

In 2017 there will be presidential and parliamentary elections in France which may see a switch to a right-wing government.

Germany.

Fracking 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 fracking of unconventional gas wells (tight gas) occurred in the mid-1990s in the Söhlingen Field, Lower Saxony, and fracking was conducted in at least three other tight gas fields in Lower Saxony in the period 2005-2010. Despite a 55-year history of fracking, there was no public interest in the application of the technology in Germany until 2010.

From 2011 onwards, while there was no formal ban on hydraulic fracturing, a number of German states introduced moratoria on the use of the process.

On 1st April 2015 the German cabinet approved draft legislation which would effectively ban hydraulic fracturing of shales for five years. The legislation was not placed before parliament, however, as the governing coalition could not find common ground on final details. The resultant lack of a reliable and proportionate legislative framework drew criticism from industry sources and gas industry employee groups. Domestic natural gas production, which uses hydraulic fracturing in tight sandstone reservoirs, had declined by almost one-third since 2011.

On 24th June 2016 a hydraulic fracturing regulatory package, which involved changes to seven laws, was approved by the German parliament. The Federal Council adopted the package on 8th July 2016. The changes to the laws distinguished between conventional and unconventional fracturing. Conventional fracturing in tight sandstone and carbonate can continue as before. Unconventional fracturing in mudstone, shale, marl and coal seams is banned for five years (until 2021). Unless the ban is raised in 2021 it will continue. The legislation did, however, give approval for unconventional fracturing in four scientific research wells, to be conducted at reservoir depths greater than 3,000 metres (~ 9,850').

***Poland*.**

Forty (40) concessions have been awarded in the Baltic Depression, of which 10, largely operated by LOTOS Petrobaltic, were offshore in the Baltic Sea and 30 lay onshore in the Gdansk Depression. Six of the most easterly concessions, such as the four held by ShaleTech Energy, are

considered to be more prospective for shale liquids than for shale gas. Twenty four (24) concessions have subsequently been relinquished. Sixteen (16) different companies have been active in the onshore Gdansk Depression at some time including ConocoPhillips, Eni, Talisman and the Polish state company, PGNiG, plus a number of small niche players, frequently active through consortia. At present, four companies remain active, principally ShaleTech Energy, LOTOS Petrobaltic and PGNiG. In September 2016, LOTOS Petrobaltic acquired its first onshore concession (Mlynary) which had previously been relinquished by Eni.

Another 40 concessions have been awarded in the Danish-Polish Marginal Trough and 16 on the East European Platform Margin, northeast of the Marginal Trough. 48 of these awards (34: Marginal Trough; 14: Platform Margin) have since been relinquished but 2 relinquishments by ExxonMobil on the East European Platform Margin were taken up by Orlen Upstream. Sixteen (16) different companies have been active in the Platform Margin and Marginal Trough, the most prominent participants having been Chevron, ExxonMobil, Marathon, Total, Polish state company PGNiG, and PKN Orlen, another Polish company. At present, three companies remain active, principally Orlen (6 concessions).

A total of 23 concessions thought to have shale gas potential have been awarded in the Fore-Sudetic Monocline in southwest Poland but 19 have subsequently been relinquished. Orlen, PPI Chorobok and Palomar Natural Resources are the only remaining licence holders. Although all 4 remaining Fore-Sudetic Monocline concessions are considered to have some shale gas prospectivity, some are also being investigated for their tight gas and conventional oil and gas prospects.

Four concessions with possible shale liquids and shale gas potential were awarded to Strzelecki Energia (Hutton Energy) in the Mogilno-Łódź Trough / Kujawy Gielniów Swell region of the Northeast German – Polish Basin and subsequently relinquished. One of these concessions (Kolo) was then reawarded in April 2016, presumably under more favourable terms.

Valid concessions at 30th November 2016 are shown below.

Polish Shale Gas and Shale Liquids Concessions at 30th November 2016						
Company / Group	**Baltic Depression**	**Danish-Polish Marginal Trough**	**East European Platform Margin**	**Fore-Sudetic Monocline**	**Mogilno-Łódź Trough**	**Valid Total**
Shale Gas Concessions						
Baltic Oil & Gas (San Leon, formerly Talisman)	1	1				2
Cuadrilla Resources Ltd		1				1
LOTOS Petrobaltic	4					4
Orlen Upstream		4	2	1		7
PGNiG	3					3
PPI Chrobok S.A.				2		2
Rawicz Energy (Palomar Capital Advisors)				1		1
ShaleTech Energy (Stena Investment)	3					3
Total Valid Shale Gas Concessions	**11**	**6**	**2**	**4**	**0**	**23**
Shale Liquids Concessions						
PGNiG	1					1
ShaleTech Energy (Stena Investment)	4					4
Strzelecki Energia (Hutton Energy)					1	1
Total Valid Shale Liquids Concessions	**5**	**0**	**0**	**0**	**1**	**6**

By 30th November 2016 a total of 90 shale gas and 4 shale liquids concessions had been relinquished in Poland, 34 in the Danish-Polish Marginal Trough, 14 on the East European Platform Margin, 19 on the Fore-Sudetic Monocline, 3 in the Northeast German – Polish Basin

and 24 in the Baltic Depression. All significant international players (Chevron; ConocoPhillips; Eni; ExxonMobil; Marathon; Talisman; Total) have now exited Poland.

Relinquishments to 30th November 2016 by company / company consortium are shown below.

Polish Shale Gas and Shale Liquids Concession Relinquishments at 30th November 2016						
Company / Group	**Baltic Depression**	**Danish-Polish Marginal Trough**	**East European Platform Margin**	**Fore-Sudetic Monocline**		**Relinquished Total**
Shale Gas Concessions						
3Legs Resources	3			3		**6**
BNK Petroleum - Indiana Investments	3					**3**
BNK Petroleum - Saponis Investments	3					**3**
Canadian International Oil Corp				2		**2**
Chevron Corp		4				**4**
Cuadrilla Resources Ltd		1				**1**
Dart Energy Ltd		1				**1**
DPV Service		5				**5**
Eni SpA	3					**3**
EurEnergy Resources (Baltic Energy Resources)	1					**1**
ExxonMobil Corp			4			**4**
ExxonMobil Corp / Total SA		1	1			**2**
LOTOS Petrobaltic	5					**5**
LOTOS Petrobaltic - Baltic Gas (CalEnergy Resources)	1					**1**
Mac Oil	1					**1**
Marathon		1				**1**
Marathon / Nexen / Mitsui		6	4			**10**
Orlen Upstream		1	1			**2**
PETROLINVEST SA - ECO Energy		1	2	1		**4**
PETROLINVEST S.A. - Silurian		1	1	3		**5**
PGNiG		10		1		**11**
San Leon - Aurelian O&G				2		**2**
San Leon - Braniew o Energy	1					**1**
San Leon - Czersk	1			2		**3**
San Leon - Helland Energy		1				**1**
San Leon - Gora Energy				1		**1**
San Leon - Liesa Energy				1		**1**
San Leon - Vabush Energy				1		**1**
San Leon - Joyce Investments (Esrey Energy 50%)	1					**1**
San Leon - Maryani Investments (Esrey Energy 50%)			1			**1**
San Leon - Strzelecki Energia (Hutton Energy 25%)		1		2		**3**
Total Relinquished Shale Gas Concessions	**23**	**34**	**14**	**19**		**90**
Company / Group	**Baltic Depression**			**Mogilno-Łódź Trough**		**Relinquished Total**
Shale Liquids Concessions						
Hutton Energy				3		**3**
PGNiG	1					**1**
Total Relinquished Shale Liquids Concessions	**1**			**3**		**4**

PGNiG (Polskie Górnictwo Naftowe i Gazownictwo – state-controlled).

Between March and May 2013 the company drilled its first well on the Stara Kiszewa concession, Wysin-1, to a depth of 13,255', some 20 miles southeast of Gdansk in the Baltic Depression. A second well, Bedomin-1, was drilled in June-August 2014. In June 2015 a follow-up horizontal well, Wysin-2H, was spudded with a planned TVD of 12,975'. The well was completed in September 2015 with a measured depth of 17,500' and horizontal leg of 3,830'. A further horizontal well, Wysin-3H, was then spudded. Wysin-3H was completed in December 2015 at a measured depth of 18,175'.

In June – August 2016 PGNiG fracture tested the horizontal legs of Wysin-2H and 3H. Flow rates were very low and as a result PGNiG decided to evaluate the continuation of its shale gas project. In mid-October 2016 Reuters reported that both PKN Orlen and PGNiG have abandoned their

shale gas projects. The CEO of PGNiG was reported as saying that while shale gas exploration as such has failed, useful lessons have been learned regarding improved techniques for unconventional gas exploration.

***Sweden*.**

AB Igrene. AB Igrene had 23 concessions with Lower Paleozoic shale potential in the Siljan Ring, where Lower Paleozoic rocks have been preserved around the margin of a depression formed by a major Late Devonian meteor impact. The company currently holds 11 concessions, with the rejection of the renewal of the other concessions being subject to appeal. To date 15 holes have been drilled including five core holes of about 1,600' each, three of them in the Mora area on the west of the ring, which is now the focus of exploration, with the last two core holes having been drilled there in Q2 2013. Produced gas is dry, exceeding 90% methane with the remainder dominantly carbon dioxide and nitrogen plus minor ethane, propane and butane. Gas occurs at depths below 1,180' in Mora-001 and below 1,000' in Solberga-1. Identified units with shale gas potential include the Tøyen Formation (Lower Ordovician), Fjäcka Shale (Upper Ordovician) and a Llandovery (Lower Silurian) shale (Kallholn Formation?), plus fractured basement.

AB Igrene commenced drilling the Vattumyren-3 well in the Mora area in July 2015. The well reached its planned TD of 2,300' at end October 2015 but failed to encounter significant gas shows. This has been attributed to the use of rotary drilling whereas percussion drilling was used on all previous wells. A stimulation programme and production test in May 2016 was cancelled after 3 days when gas volumes rose sharply, risking a blow-out.

A production well, planned to 1,640', was spudded in July 2016. It encountered gas (95% methane) at 845' and drilling was suspended. Further wells are planned for December 2016 to February 2017.

[*Note*: In the late 1980s, the Gravberg-1 well was drilled through a fractured granite within the impact crater to a TD of 22,000' to test Thomas Gold's theory of the abiogenic origin of petroleum.]

***United Kingdom*.**

On 16th December 2015, members of parliament approved a statutory instrument which amended the 2105 Infrastructure Act to allow hydraulic fracturing 1,200 metres (3,937') below national parks and sites of special scientific interest, as long as drilling takes place from outside protected areas.

Cuadrilla Resources applied to Lancashire county council in May 2014 to drill and frac a number of wells on two sites (Preston New Road and Roseacre Wood). The county council repeatedly delayed proceedings and finally rejected the bids in June 2015. (See Cuadrilla below)

Subsequently, on 13 August 2015, the UK government announced new measures for shale gas planning applications to be fast-tracked through a new, dedicated planning process which could deny councils the right to decide fracking applications unless they approve them quickly.

As part of the new measures, appeals against any refusals of planning permission for exploring and developing shale gas must be treated as a priority for urgent resolution. Councils that repeatedly fail to determine oil and gas applications within the 16 week statutory timeframe (unless applicants agree to a longer period) will be identified and, where applications are made to underperforming local planning authorities, the Secretary of State for Communities and Local Government will consider whether he/she should determine the application instead of the relevant council. The result of the first such appeal was announced on 6th October 2016 (see Cuadrilla below).

England

On 18th August 2015, the Oil & Gas Authority (OGA) – the UK's oil and gas regulator –announced that 27 onshore blocks from the 14th Onshore Oil and Gas Licensing Round would be formally offered to companies. Successful applicants in the first 27 blocks awarded included Cuadrilla Resources, Egdon Resources, GDF Suez, Hutton Energy, IGas, INEOS and Total. The acreage awarded includes prospective shale gas acreage in the Rossendale Basin, Humber Basin, Gainsborough Trough, Widmerpool Gulf and other parts of the East Midlands Shelf.

A second group of 132 additional blocks was subjected to detailed assessment under the Conservation of Habitats and Species Regulations 2010, which was subject to public consultation.

On 17th December 2015 the Oil & Gas Authority announced that all 159 onshore blocks under the UK's 14th Onshore Oil and Gas Licensing Round were being formally offered to successful applicants. These blocks will be incorporated into 93 onshore licences. Around 75% of the 159 blocks being offered relate to unconventional shale oil or gas. The licences for all offered blocks will then be granted after the terms and conditions have been finalised.

Scotland

On 28th January 2015 the Scottish Government Energy Minister announced a moratorium on the granting of planning consents for all unconventional oil and gas developments, including fracking. This moratorium will continue until technical work on planning, environmental regulation and assessing the impact on public health, and a full public consultation on unconventional oil and gas extraction, have been completed.

The UK government was already committed to Scotland having devolved powers for licensing of oil and gas as part of its efforts to give the Scottish government more decision-making powers. On 26th February 2015 the UK government therefore announced that it has agreed in principle not to award licences in Scotland for unconventional oil and gas exploration in the current 14th Onshore Licensing Round, though consultation with companies who have already applied will be undertaken before making a final decision.

On 8th October 2015, the Scottish Government extended the moratorium to cover underground coal gasification (UCG).

Cuadrilla Resources. On 4th February 2014, Cuadrilla announced that the company intended to apply for planning permission to drill, hydraulically fracture and flow test up to four exploration wells on each of two sites, one at Roseacre Wood, Roseacre, and the other at Preston New Road,

Little Plumpton. Separate applications were also made to install two seismic arrays that will be used to monitor the hydraulic fracturing process.

Planning applications were submitted on 29th May (Preston New Road) and 16th June 2014 (Roseacre Wood). The Environment Agency granted the necessary environmental permits for shale gas exploration on 16th January (Preston New Road) and 6th February 2015 (Roseacre Wood). The company still required planning permission from Lancashire County Council before operations could proceed. In January 2015 Cuadrilla asked for a deferral of the planning applications to address noise and traffic issues that had been identified by the Council's planning officers. In February 2015 the Council rejected an application to use the Grange Hill site for pressure testing and seismic monitoring. The site is now in limbo as permission to plug the well and restore the site was also refused.

In June 2015 Lancashire County Council refused planning permission for the two sites, despite a recommendation of approval for the Preston New Road site from the council's planning officer. The reasons given for refusal were noise and visual impact (Preston New Road) and traffic (Roseacre Wood).

Cuadrilla appealed the decisions and 6-week public enquiry commenced before a planning inspector on 9th February 2016. The inspector's recommendation was due to be submitted to the Secretary of State for Communities and Local Government by 4th July 2016 but the recommendation was not to be made public until the Secretary of State had made his decision.

On 6th October the Secretary of State for Communities and Local Government announced approval of Cuadrilla's plan to drill and fracture 4 wells at the Preston New Road site. Cuadrilla have been given time to submit revised proposals on traffic management for the Roseacre Wood site before a final decision is reached on this appeal. Current licence terms for the PEDL 165 licence require one horizontal well to be drilled and fractured by 30th June 2019 and Field Development Plan to be submitted by 30th June 2012. Site preparation work at Preston New Road is expected to commence early in 2017, well in advance of the licence drilling requirement.

Viking UK Gas. Between June and October 2013, Viking UK Gas, a wholly owned subsidiary of Third Energy, which in turn is 97% owned by a private equity arm of Barclays Bank, drilled Kirby Misperton-8 as a deep Bowland Shale appraisal well on the Kirby Misperton conventional field (PL 80) in the Cleveland Basin, North Yorkshire. The neighbouring Kirby Misperton-1 had encountered ~ 2,500' of Bowland Shale when drilled in 1985. In July 2015 a planning application was submitted to hydraulically fracture Kirby Misperton-8. The application went through the public consultation process and was considered and approved by North Yorkshire's planning committee on 20th May 2016, subject to the company meeting 40 conditions. The permission was challenged by local resident group Frack Free Ryedale and Friends of the Earth and a judicial review was held in the High Court in London on 22nd and 23rd November. On 20th December 2016 Mrs Justice Lang decreed that North Yorkshire County Council had acted lawfully in approving the application to fracture test Kirby Misperton-8 and the company can now proceed to meet the conditions required by the council after which it can test the well.

IGas. In October 2015, IGas submitted a planning application to Nottinghamshire County Council to drill one vertical well to approximately 11,500' and one adjacent horizontal well at Springs Road on PEDL 140 in the Gainsborough Trough, East Midlands. Following a period of public consultation, in February 2016 the council requested further information from IGas. Following receipt of the information requested, there was a further period of public consultation. On 15th November 2016 Nottinghamshire Council's planning committee approved the plans and

drilling can now proceed subject to a legal agreement on heavy traffic serving the site, which should be ready by end January 2017.

A further application to drill a vertical shale gas exploration well at Tinker Lane on PEDL 200 in the Gainsborough Trough will be heard by Nottinghamshire Council's planning committee early in 2017. The licence terms for PEDL 200 require one well to be drilled by 31st December 2017 and a horizontal well by June 2021.

On 17th October 2016, IGas published DeGolyer and MacNaughton's estimate of prospective unconventional resources as of 31st July 2016 on 31 prospects in which IGas has an interest. After application of a geological chance factor based on the probability of geological success (average: 23%) the prospective resources were estimated at 5.44 Tcf (gross) and 2.54 Tcf (IGas working interest).

Horse Hill Developments. Horse Hill Developments, as operator, drilled Horse Hill-1 between September and November 2014 on PEDL 137 in the Weald Basin to a TD of 8,770' in Paleozoic rocks. A conventional oil discovery was made in the Portland Sandstone (Upper Jurassic). The well also identified potential recoverable liquids within a 653' aggregate net pay in naturally fractured argillaceous limestone and mudstone of the Kimmeridge Clay and mudstones of the Oxford and Lower Lias intervals. The Kimmeridge section contains 511' net pay with average TOC of 2.8% and calculated oil-in-place of 115 million bbl / square mile.

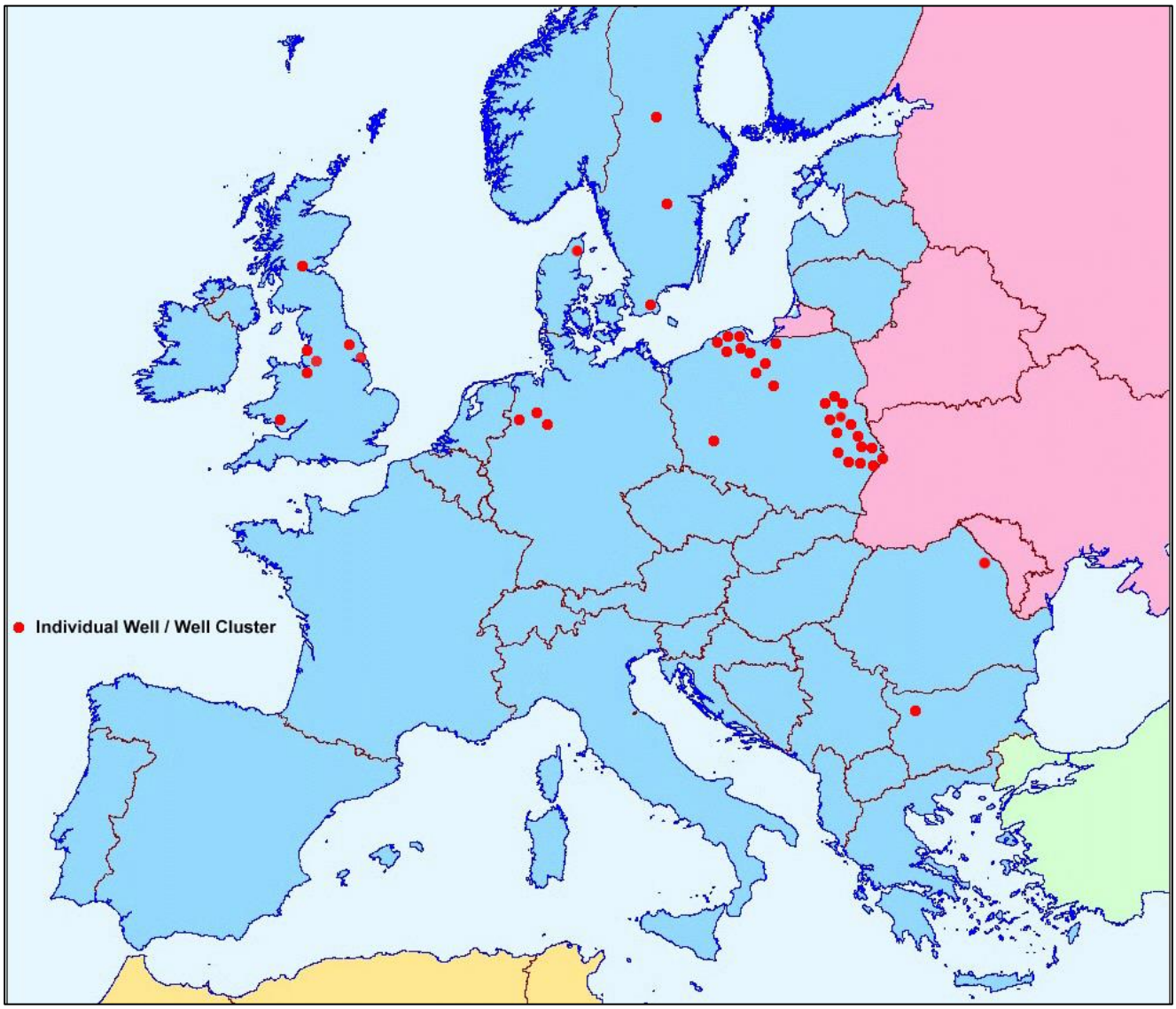
The hydrocarbon occurrence appears to be analagous to Cuadrilla's Balcombe-2 discovery and it is believed that the liquids can be developed by conventional horizontal drilling and completion techniques without recourse to hydraulic fracturing. The productive intervals are shallower than the 1,000 metre (3,280') upper permissible limit for hydraulic fracturing in the UK.

The well was placed on flow test in Spring 2016. An upper limestone interval in the Middle Kimmeridge Clay was perforated over an 88' aggregate interval at about 2,750' and flowed in excess of 900 bo/d of 40° oil. A lower limestone interval in the Middle Kimmeridge Clay at around 2,950' flowed in excess of 460 bo/d from an 80' perforated zone. The conventional Portland Sandstone was also tested and flowed at over 300 bo/d over an 8.5 hour period.

The licence terms for PEDL 137 require a horizontal sidetrack to be drilled from Horse Hill-1 by 30th September 2017.

Appendix 1.

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



Appendix 2.Shale gas exploration and appraisal wells drilled in Europe

Sub-Province	Concession	Well Name	No	Operator	Spud	Compl	TD ft	Horiz	Fracs	Target Fm	Result - Content
	A-Lovech	Goljamo Peshtene	R-11	LNG Energy	27-Sep-11	End Nov-11 @TD	10,466			Etropole	numerous show s C1 - C3
	A-Lovech	Deventci	R-2	TransAtlantic Petroleum	27-Oct-11					Etropole	
	1/10 Nordjylland	Vendsyssel	1	Total	04-May-15	17-Aug-15	11,694			Alum Shale	gas show s
Low er Saxony Basin	Münsterland	Damme	2	ExxonMobil	2008	2008	10,950			Wealden, Posidonia	
Low er Saxony Basin	Münsterland	Damme	2A	ExxonMobil	2008	2008	10,935			Posidonia Shale	
Low er Saxony Basin	Münsterland	Damme	3	ExxonMobil	2008	2008	5,280		3	Wealden	
Low er Saxony Basin	Minden	Oppenw ehe	1	ExxonMobil	Jun-08	2008	8,730			Wealden, Posidonia	
Low er Saxony Basin	Schaumberg	Niedernw öhren	1	ExxonMobil	2009	2009	3,394			Wealden	
Low er Saxony Basin	Scholen-Barenburg II	Schlahe	1	ExxonMobil	2009	2009	4,870			Wealden, Posidonia	
Low er Saxony Basin	Bramschen	Lünne	1	ExxonMobil	17-Jan-11	Mar-11	5,170			Wealden, Posidonia	
Low er Saxony Basin	Bramschen	Lünne	1A	ExxonMobil	Mar-11	2011	5,503	Y		Posidonia Shale	
Gdansk Depression	Trzebielino	Miszew o	T-1	Indiana Investments (BNK)	28-Feb-12	Sep-12	17,700			Low Paleozoic	Muted gas show s
Gdansk Depression	Bytow	Gapow o	B-1	Indiana Investments (BNK)	Mid-late May 12	Jul-12	14,100			Low Paleozoic	Major gas show s
Gdansk Depression	Bytow	Gapow o	B-1A	Indiana Investments (BNK)	Mid-Jan 14	23-Feb-14		Y	20 (8 effective)	Low Paleozoic	High gas show s
Gdansk Depression	Slaw no	Wytow no	S1	Saponis Investments	Dec-10	14-Feb-11	11,750			Low Paleozoic	significant gas show s: C1 - C3
Gdansk Depression	Slupsk	Lebork	S1	Saponis Investments	11-Mar-11	25-Apr-11	11,780		Y	Low Paleozoic	significant gas show s: C1 - C3
Gdansk Depression	Starogard	Starogard	S1	Saponis Investments	16-Jul-11	Sep-11	11,560			Low Paleozoic	significant gas show s: C1 - C5
Gdansk Depression	Lębork	Łebień	LE-1	Lane Energy (3Legs)	Mid Jun-10	28-Jul @ TD	10,120		1; DFIT	Low Paleozoic	gas
Gdansk Depression	Lębork	Łebień	LE-2H	Lane Energy (3Legs)	10-May-11	Jun-11		Y	13	Low Paleozoic	gas show s
Gdansk Depression	Lębork	Strzeszew o	LE-1	Lane Energy (3Legs)	04-Oct-12	Early Dec-12	10,040		DFIT; 2 fracs	Low Paleozoic	
Gdansk Depression	Lębork	Lublew o	LEP-1	Lane Energy (3Legs)	13-Dec-13	20-Jan-14	9,593			Low Paleozoic	
Gdansk Depression	Lębork	Lublew o	LEP-1ST1H	Lane Energy (3Legs)	02-Apr-14	28-Apr-14	14,688	Y	25 fracs	Sasino Fm	
Gdansk Depression	Kaw ia	Slaw oszyno	LEP-1	Lane Energy (3Legs)	15-Feb-14	17-Mar-14	9,250			Low Paleozoic	
Gdansk Depression	Cedry Wielkie	Łęgow o	LE-1	Lane Energy (3Legs)	27-Aug-10	Q4-2010	11,270		2 DFITs	Low Paleozoic	gas show s
Gdansk Depression	Damnica	Warblino	LE-1H	Lane Energy (3Legs)	17-Jul-11	Sep-11	10,570	Y	7	Low Paleozoic	gas show s
Gdansk Depression	Gdansk-W	Lew ino	1G-2	Talisman Energy Polska	26-Sep-11	17-Nov-11	11,800		3	Low Paleozoic	C1+ small C2-C5
Gdansk Depression	Elblag	Bagart	1	Eni Polska	01-Dec-11	Mar-12				Low Paleozoic	
Gdansk Depression	Elblag	Stare Miasto	1	Eni Polska	Apr-12	Sep-12			Y	Low Paleozoic	
Gdansk Depression	Malbork	Kamionka	1	Eni Polska	May-12	Aug-12				Low Paleozoic	
Gdansk Depression	Wejherow o	Lubocino	1	PGNiG	Dec-10	Mar-11	10,010		2	Low Paleozoic	promising gas flow . No H2S and low N2. Heavier hydrocarbons
Gdansk Depression	Wejherow o	Lubocino	2H	PGNiG	Aug-12	Nov-12	13,060	Y	DFIT; 6 fracs	Low Paleozoic	
Gdansk Depression	Wejherow o	Lubocino	3H	PGNiG	Aug-13	Dec-13	11,720	Y		Low Paleozoic	
Gdansk Depression	Wejherow o	Opalino	2	PGNiG	Sep-12	Dec-12	10,000			Low Paleozoic	flow ed gas
Gdansk Depression	Wejherow o	Opalino	3	PGNiG	Nov-13	Jan-14	10,070			Low Paleozoic	
Gdansk Depression	Wejherow o	Opalino	4	PGNiG	Jan-14	Apr-14	10,170			Low Paleozoic	
Gdansk Depression	Wejherow o	Tepcz	1	PGNiG	Apr-14	Jun-14	11,090				
Gdansk Depression	Stara Kiszew a	Wysin	1	PGNiG	Mar-13	May-13	13,255			Low Paleozoic	
Gdansk Depression	Stara Kiszew a	Wysin	2H	PGNiG	Mid Jun-15	Sep-15	17,497	Y	Y	Low Paleozoic	low gas flow rate
Gdansk Depression	Stara Kiszew a	Wysin	3H	PGNiG	Sep-15	Dec-15	18,175	Y	Y	Low Paleozoic	low gas flow rate
Gdansk Depression	Stara Kiszew a	Będomin	1	PGNiG	Jun-14	Aug-14				Low Paleozoic	
Gdansk Depression	Wejherow o	Kochanow o	1	PGNiG	May-13	Jun-13	10,750			Low Paleozoic	
Gdansk Depression	Kartuzy-Szemud	Borcz	1	PGNiG	Jul-13	Sep-13	12,335			Low Paleozoic	
Gdansk Depression	Kartuzy-Szemud	Miłow o	1	PGNiG	May-14	Jul-14				Low Paleozoic	

Appendix 2 (continued). Shale gas exploration and appraisal wells drilled in Europe

Geological Province	Sub-Province	Concession	Well Name	No	Operator	Spud	Compl	TD ft	Horiz	Fracs	Target Fm	Result - Content
Poland (continued)												
Danish-Polish Marginal Trough	Lublin Trough	Grabowiec	Grabowiec	G6	Chevron Polska	31-Oct-11	Feb-12			DFIT	Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Frampol	Frampol	1	Chevron Polska	Mar-12	Apr-12				Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Zwierzyniec	Zwierzyniec	1	Chevron Polska	Dec-12	Mar-13			DFIT; frac	Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Krasnik	Krasnik	1	Chevron Polska	May-13	Aug-13				Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Chelm	Krupe	1	ExxonMobil E&P Poland	03-Dec-10	Jan-11	12,490		Y	Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Pionki-Kazimierz	Markowola	1	PGNiG	Apr-10	Jun-10			1	Upp Carb	
Danish-Polish Marginal Trough	Lublin Trough	Tomaszów Lubelski	Lubycza Królewska	1	PGNiG	26-Mar-12	Aug-12	11,495			Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Tomaszów Lubelski	Majdan Sopocki	1	PGNiG	21-=Oct-14	Dec-14					
Danish-Polish Marginal Trough	Lublin Trough	Wiszniow-Tarnoszyn	Kościaszyn	1	PGNiG	Oct-13	Jan-14	12,560			Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Kock-Tarkawica	Wojcieszków	1	PGNiG	Sep-13	Dec-13	10,150			Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Wierzbica	Syczyn	OU1	Orlen Upstream	24-Oct-11	Dec-11	9,445			Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Wierzbica	Syczyn	OU2K	Orlen Upstream	24-Sep-12	Early Nov-12	13,450	Y	12	Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Wierzbica	Stręczyn	OU1	Orlen Upstream	22-Feb-13	Apr-13	11,480			Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Wierzbica	Stręczyn	OU1-K	Orlen Upstream	Sep-14	Oct-14		Y			
Danish-Polish Marginal Trough	Lublin Trough	Wierzbica	Dobryniów	OU1	Orlen Upstream	26-Jun-13	Sep-13				Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Lubartów	Berejow	OU1	Orlen Upstream	Mid Dec-11	Jan-12	8,573			Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Lubartów	Berejow	OU2K	Orlen Upstream	12-Dec-12	Feb-13	12,565	Y	7	Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Lubartów	Uscimów	OU1	Orlen Upstream	May-13	04-Jul-13				Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Garwolin	Goździk	OU1	Orlen Upstream	16-Jul-12	Oct-12	13,830			Low Paleozoic	
Danish-Polish Marginal Trough	Pomeranian Trough	Rypin	RYP-Lutocin	1	Marathon Oil Poland	Early Apr-12	Jul-12			Y	Low Paleozoic	
Danish-Polish Marginal Trough	Pomeranian Trough	Kwidzyn	KWI-Prabuty	1	Marathon Oil Poland	18-Jul-12	Sep-12			DFIT; frac	Low Paleozoic	
Danish-Polish Marginal Trough	Pomeranian Trough	Brodnica	BRO-NM Lubawskie	1	Marathon Oil Poland	Sep-12	Dec-12			DFIT	Low Paleozoic	
Danish-Polish Marginal Trough	Pomeranian Trough	Szczawno	Szymkowo	1	Talisman Energy Polska	07-Mar-12	Jun-12	14,930	Y		Low Paleozoic	C1 - C3
East European Platform Margin	Podlasie Depression	Minsk Mazowiecki	Siennica	1	ExxonMobil E&P Poland	20-Feb-11	Apr-11			Y	Low Paleozoic	
East European Platform Margin	Podlasie Depression	Siedlce	SIE-Domanice	1	Marathon Oil Poland	Jan-12	Mar-12				Low Paleozoic	
East European Platform Margin	Podlasie Depression	Sokolow Podlaski	SOK - Grębków	1	Marathon Oil Poland	Dec-12	Jan-13				Low Paleozoic	
East European Platform Margin	Podlasie Depression	Wodynie-Lukow	Stoczek	OU1	Orlen Upstream	18-Nov-13	Jan-14	10,300			Low Paleozoic	
East European Platform Margin	Podlasie Depression	Wodynie-Lukow	Stoczek	OU1K	Orlen Upstream	Jan-14	Mid Mar-14	14,130	Y	Y	Silurian	
East European Platform Margin	Podlasie Depression	Wolomin	Pęclin	OU1	Orlen Upstream	Dec-14	Mid Mar-15	12,505				
East European Platform Margin	Volhyno-Podolian Monocline	Orzechow	ORZ-Cycow	1	Marathon Oil Poland	Dec-11	Jan-12			DFIT; frac	Low Paleozoic	
Fore-Sudetic Monocline		Gora	Siciny	2	Gora Energy (San Leon)	10-Nov-11	Mid Feb-12	11,550		DFIT	Low Carb	C1 - C3
Fore-Sudetic Monocline		Rawicz	Rawicz	12 SL-1								
Romania												
South Carpathian Basin		EV-2 Barlad	Silistea-Pungesti	1	Chevron Romania E&P	Early May-14	Early July-14	9,850				

Appendix 2 (continued). Shale gas exploration and appraisal wells drilled in Europe

Geological Province	Sub-Province	Concession	Well Name	No	Operator	Spud	Compl	TD ft	Horiz	Fracs	Target Fm	Result - Content
Sweden												
Östergötland Lower Paleozoic		Motala area	5 wells		Aura Energy	Early Oct-11	Q4-2011				Alum Shale	
Östergötland Lower Paleozoic		Ekeby	Brunneby	BY-1	Gripen Energy	Mar-12	Mar-12	282			Alum Shale	weak flow of flammable gas
Östergötland Lower Paleozoic		Ekeby	Bobergs Häradallmänings	BH-1	Gripen Energy	Mar-12	Mar-12	328			Alum Shale	weak flow of flammable gas
Östergötland Lower Paleozoic		Ekeby	Rocklunda	RL-1	Gripen Energy	Mar-12	Mar-12	282			Alum Shale	weak flow of flammable gas
Östergötland Lower Paleozoic		Ekeby	Ekebyborna	GH-2	Gripen Energy	Mar-12	Mar-12	328			Alum Shale	21 Mscfd in 2-hour flow - 97.5% CH4
Östergötland Lower Paleozoic		Ekeby	Ekebyborna	GH-1A	Gripen Energy	Sep-12	Sep-12	300			Alum Shale	strong gas flow
Östergötland Lower Paleozoic		Ekeby	Ekebyborna	GH-2A	Gripen Energy	Sep-12	Sep-12	340			Alum Shale	gas flow
Östergötland Lower Paleozoic		Ekeby	Ekebyborna	GH-3	Gripen Energy	Sep-12	Sep-12	305			Alum Shale	intermittent gas flow
Östergötland Lower Paleozoic		Ekeby	Fossala	FA-2	Gripen Energy	22-Jun-13	28-Jun-13	352			Alum Shale	
Östergötland Lower Paleozoic		Ekeby	Kullen KN-1	GH-5	Gripen Energy	18-Jun-13	24-Jun-13	366			Alum Shale	3.1 Mscfd after 30 minutes
Östergötland Lower Paleozoic		Ekeby	Uddenä	UD-1	Gripen Energy	10-Jun-13	14-Jun-13	355			Alum Shale	no details
Östergötland Lower Paleozoic		Ekeby	3 appraisal wells		Gripen Energy	May to Aug 15	May to Aug 15				Alum Shale	Flowed gas
Östergötland Lower Paleozoic		Orlunda	1 exploration well		Gripen Energy	May to Aug 15	May to Aug 15				Alum Shale	Flowed gas
Östergötland Lower Paleozoic		Eneby	2 exploration wells		Gripen Energy	May to Aug 15	May to Aug 15				Alum Shale	Flowed gas
Siljan Ring Depression			5 percussion holes		AB Igrene	2008	2009				Low Paleozoic	
Siljan Ring Depression			3 rotary holes		AB Igrene	Unknown	Unknown				Low Paleozoic	
Siljan Ring Depression			Mora	001	AB Igrene	2010	2010	~1,650			Low Paleozoic	
Siljan Ring Depression			Solberga	1	AB Igrene	2011	2011	~1,650			Low Paleozoic	
Siljan Ring Depression			Stumsnäs	1	AB Igrene	2011	2011	~1,650			Low Paleozoic	
Siljan Ring Depression			Mora	002	AB Igrene	Q2-2013	Q2-2013	1,670			Low Paleozoic	
Siljan Ring Depression			Mora	003	AB Igrene	Q2-2013	Q2-2013	1,450			Low Paleozoic	
Siljan Ring Depression			Vattumyren	3	AB Igrene	20-Jul-15	End Oct-15	2,300			Low Paleozoic	
Siljan Ring Depression			Mora		AB Igrene	Jul-16					Low Paleozoic	
Fennoscandian Border Zone	Colonus Shale Trough	Colonussänkan	Lövestad	A3-1	Shell	28-Nov-09		3,134			Alum Shale	
Fennoscandian Border Zone	Colonus Shale Trough	Colonussänkan	Oderup	C4-1	Shell			3,010			Alum Shale	
Fennoscandian Border Zone	Colonus Shale Trough	Colonussänkan	Hedeberga	B2-1	Shell			2,448			Alum Shale	
United Kingdom												
Anglo-Dutch Basin	Cleveland Basin	PL 080	Kirby Misperton	8	Viking UK Gas	06-Jun-13	04-Oct-13	~10,000			Bowland Shale	
Anglo-Dutch Basin	Humber Basin	PEDL 183	Crawberry Hill	1	Rathlin Energy (UK)	15-Apr-13	12-Aug-13	~9,000		DFIT	Bowland Shale	
Anglo-Dutch Basin	Humber Basin	PEDL 183	West Newton	1	Rathlin Energy (UK)	27-Jun-13	06-Sep-13	~10,420		DFIT	Bowland Shale	
Cheshire Basin	Rossendale Basin	PEDL 190	Ince Marshes	1	IGas	04-Nov-11	21-Jan-12	5,174			Bowland Shale	gas indications
Cheshire Basin	Rossendale Basin	PEDL 184	Ellesmere Port	1	IGas	15-Nov-14	22-Dec-14				Sabden & Bowland shales	Significant gas indications
Cheshire Basin	Rossendale Basin	PEDL 193	Irlam	1	IGas	10-Jan-14	03-Mar-14	7,004			Sabden & Bowland shales	
Cheshire Basin	Rossendale Basin	PEDL 193	Irlam	1Z	IGas	03-Mar-14	31-Mar-14				Sabden & Bowland shales	
East Irish Sea Basin	West Bowland Basin	PEDL 165	Preese Hall	1	Cuadrilla	16-Aug-10	08-Dec-10	9,098		5	Bowland Shale	substantial gas flows
East Irish Sea Basin	West Bowland Basin	PEDL 165	Grange Hill	1	Cuadrilla	15-Jan-11	15-Apr-11				Bowland Shale	
East Irish Sea Basin	West Bowland Basin	PEDL 165	Grange Hill	1Z	Cuadrilla	15-Apr-11	Early Aug-11	10,775			Bowland Shale	
East Irish Sea Basin	West Bowland Basin	PEDL 165	Becconsall	1	Cuadrilla	23-Aug-11	13-Oct-11				Bowland Shale	
East Irish Sea Basin	West Bowland Basin	PEDL 165	Becconsall	1Z	Cuadrilla	13-Oct-11	21-Dec-11	10,500			Bowland Shale	
East Irish Sea Basin	West Bowland Basin	PEDL 165	Anna's Road	1	Cuadrilla	06-Oct-12	21-Nov-13	2,000			Bowland Shale	Junked & Abandoned
Midland Valley of Scotland	Kincardine Basin	PEDL 133	Airth	6	Composite Energy	15-Oct-05	05-Dec-05	3,524			Black Metals MB	
Midland Valley of Scotland	Kincardine Basin	PEDL 133	Longannet	1	Composite Energy	16-Feb-07	29-Apr-07				Black Metals MB	
Midland Valley of Scotland	Kincardine Basin	PEDL 133	Bandeath	1	Composite Energy	15-May-07	18-Jun-07				Black Metals MB	
South Wales Carboniferous		PEDL 148	Banwen	1	UK Methane	07-Sep-11	16-Sep-11				Aberkenfig?	
South Wales Carboniferous		PEDL 149	St Johns	1	UK Methane	26-Aug-11	23-Mar-12				Aberkenfig?	

Appendix 3. Shale liquids exploration and appraisal wells drilled in Europe.

Geological Province	Sub-Province	Concession	Well Name	No	Operator	Spud	Compl	TD ft	Horiz	Fracs	Target Fm	Result - Content
Lithuania												
Baltic Depression		Gargzdai	Skomantai	1	Minijos Nafta	Mid-May-12	Jul-12	7,975			Low Paleozoic	
Poland												
Baltic Depression	Gdansk Depression	Kętrzyn	Rodele	1	Wisent Oil & Gas	11-Feb-13	Early Mar-13	5,075		3	Low Paleozoic	
Baltic Depression	Gdansk Depression	Lidzbark Warmiński	Babiak	1	Wisent Oil & Gas	Mid Mar-13	May-13	9,160		Y	Low Paleozoic	
Baltic Depression	Gdansk Depression	Lidzbark Warmiński	Mingajny	1	Wisent Oil & Gas	Mar-14	Apr-14				Low Paleozoic	
Baltic Depression	Gdansk Depression	Braniewo	Rogity	1	Talisman Energy Polska	12-Dec-11	14-Feb-12	9,147			Low Paleozoic	C1-nC8
United Kingdom												
Anglo-Paris Basin	Weald Basin	PEDL 137	Horse Hill	1	Horse Hill Developments	02-Sep-14	04-Nov-14	8,770			Kimmeridge Micrite	hydrocarbon liquids
Anglo-Paris Basin	Weald Basin	PEDL 244	Balcombe	2	Cuadrilla Resources	02-Aug-13	05-Sep-13	2,700			Kimmeridge Micrite	hydrocarbon liquids
Anglo-Paris Basin	Weald Basin	PEDL 244	Balcombe	2Z	Cuadrilla Resources	05-Sep-13	22-Sep-13		Y		Kimmeridge Micrite	hydrocarbon liquids

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http://www.eia.gov/analysis/studies/worldshalegas/pdf/fullreport.pdf

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EIA Shale in the United States.
http://www.eia.gov/energy_in_brief/article/shale_in_the_united_states.cfm

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EIA Barnett Shale Poster

http://www.eia.gov/oil_gas/rpd/shaleusa1.pdf

EIA Barnett Shale Drilling from 1981 to 2010 (updated May 2011)

http://www.eia.gov/maps/maps.htm

EIA Eagle Ford Shale Poster

http://www.eia.gov/maps/pdf/eagleford122914.pdf

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EIA Fayetteville Shale Poster

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http://www.eia.gov/oil_gas/rpd/shaleoil1.pdf (updated March 2011)

EIA Bakken Shale Production from 1985 to 2010 (updated September 2011)

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http://www.csug.ca/

Shale Gas and Liquids Calendar 2017

April 3-5, 2017: DUG Permian Basin, Fort Worth, TX, Hart Energy conferences, http://www.hartenergyconferences.com/future-events

April 28-30, 2017: Fundamental Controls on Shale Oil Resources and Production, AAPG Hedberg Conference, Beijing, China.
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June 20-22, 2017: DUG East, Pittsburgh, PA, Hart Energy conferences,
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August 29-31, 2017: DUG Eagle Ford, San Antonio, TX, Hart Energy conferences,
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September 19-21, 2017: DUG Midcontinent, Oklahoma City, OK, Hart Energy conferences,
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