Advanced Reservoir Engineering

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References

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- Shu Jiang et al., 2019, Petroleum Geoscience and Engineering for Shale Gas and Shale Oil, Cambridge

Chapter 8 Unconventional Hydrocarbon Reservoirs

Section 1 Introduction of Unconventional Hydrocarbon Reservoirs

Section 2 Reservoir Characterization Of Unconventional Reservoirs (tight sand, CBM, shale)

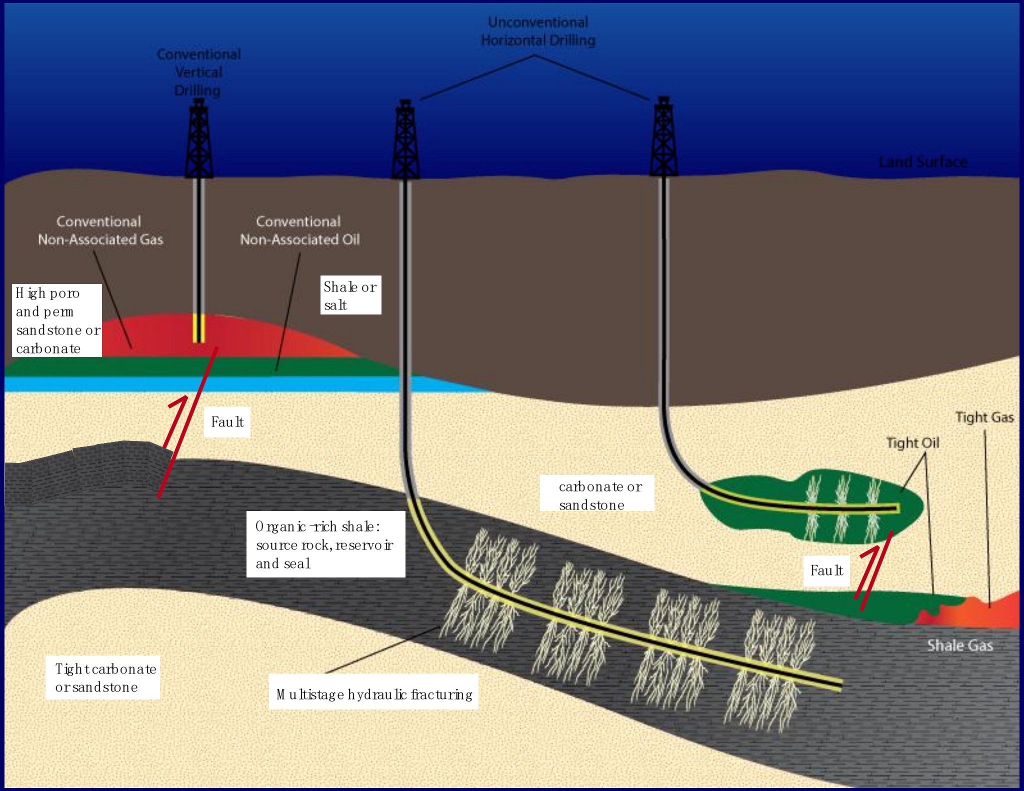
Section 3 Development of Unconventional Hydrocarbon Reservoirs

Section 1 Introduction of Unconventional Hydrocarbon Reservoirs

Definition of Unconventional Reservoirs

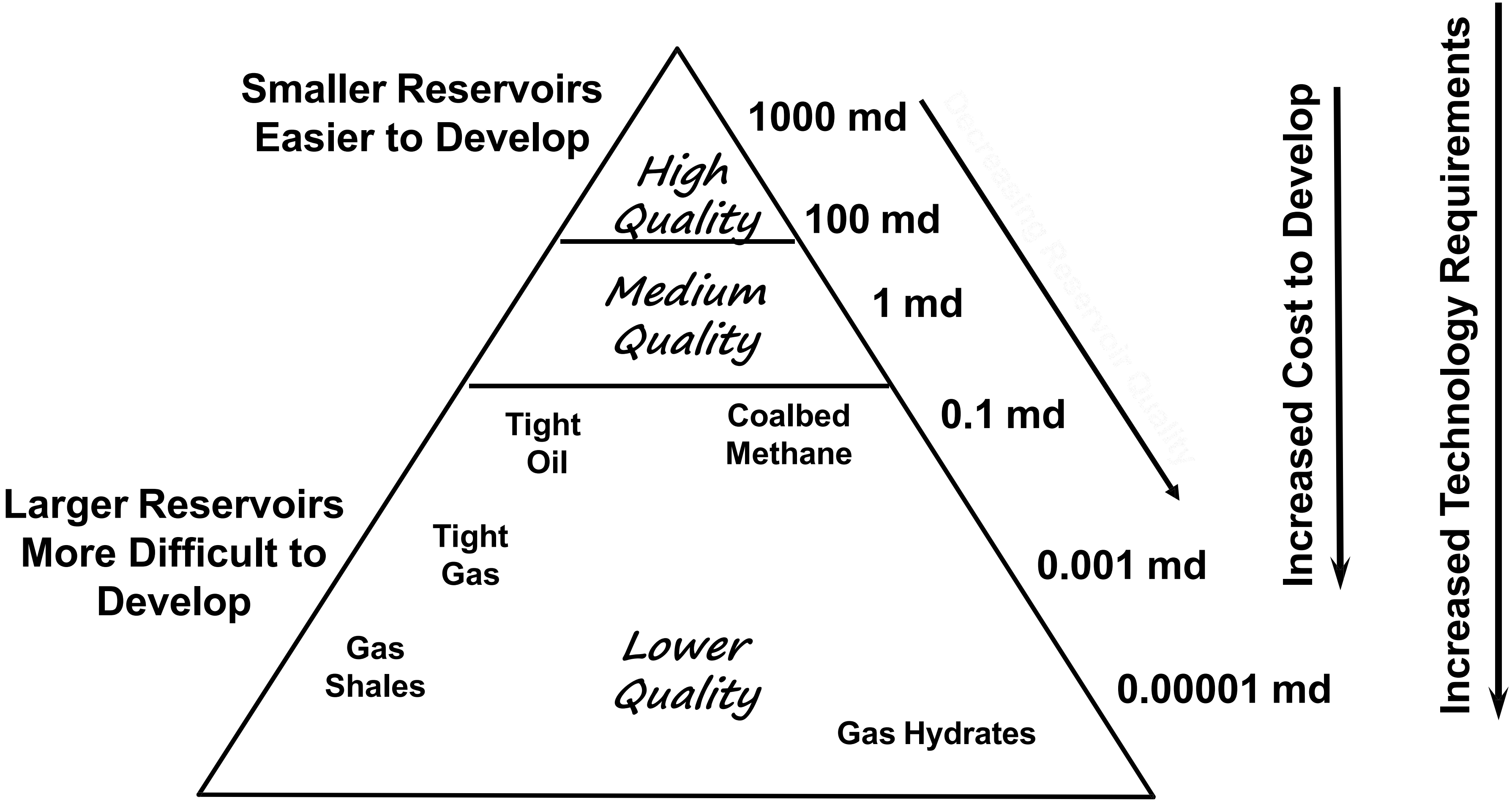
- Unconventional oil or gas that is produced from what industry would call unconventional Reservoirs
- Oil or gas reservoir is usually distributed over a large geographic area and will host local regions of improved productivity (sweet spots)
- Gas and oil is held in tight reservoir by either pressure or low permeability
- Often these reservoirs are of a lower quality and require enhanced technology types of completions to yield (e.g. hydraulic fracturing) commercially successful wells

- Can be both source and reservoir as in the case of shale gas or CBM (resource play)
- Do not necessarily need a trap but generally need a seal
- Over time the technology makes production conventional

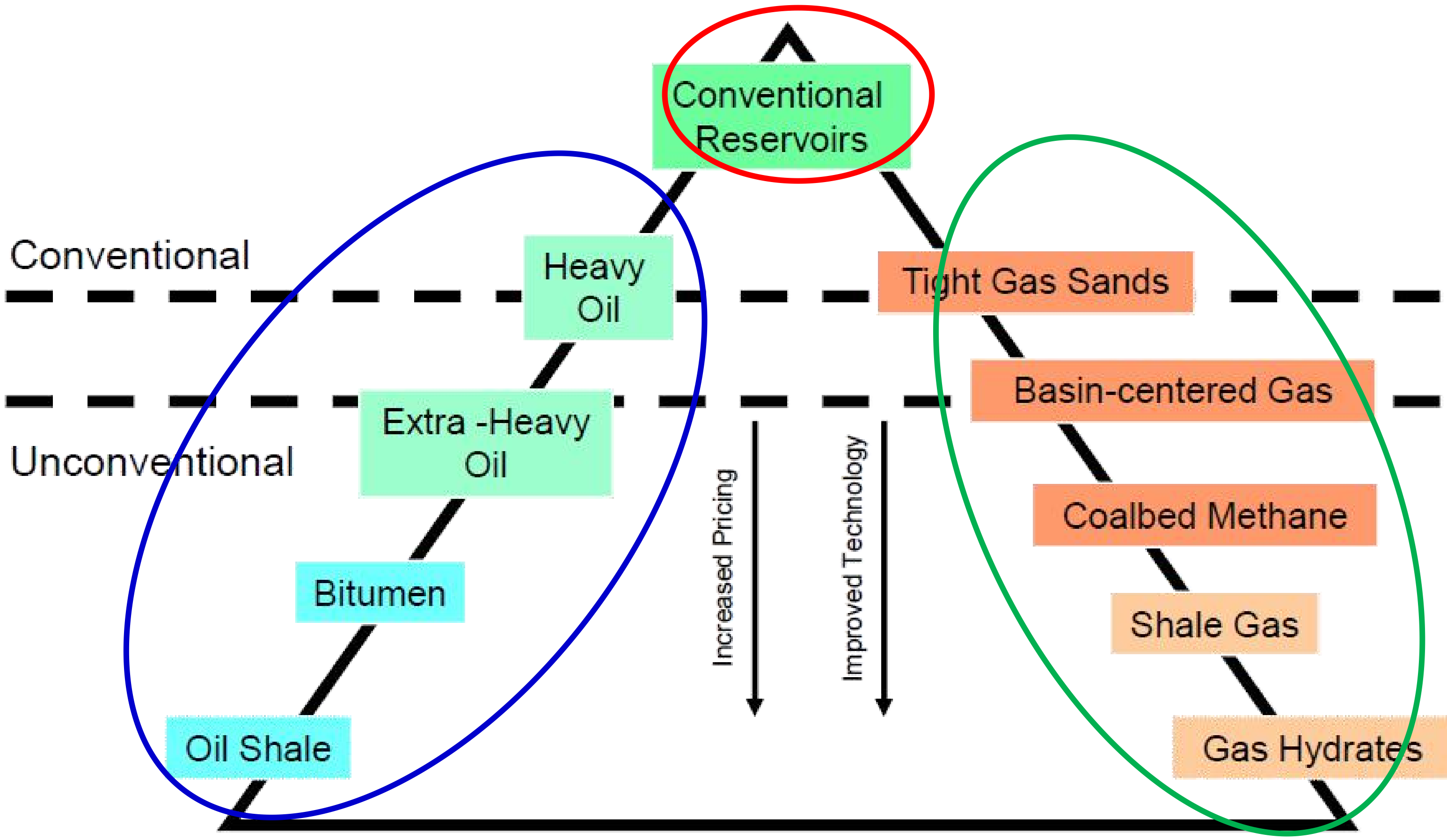


Conventional VS Unconventional Resources

Conventional Reservoirs



Types of Unconventional Resources

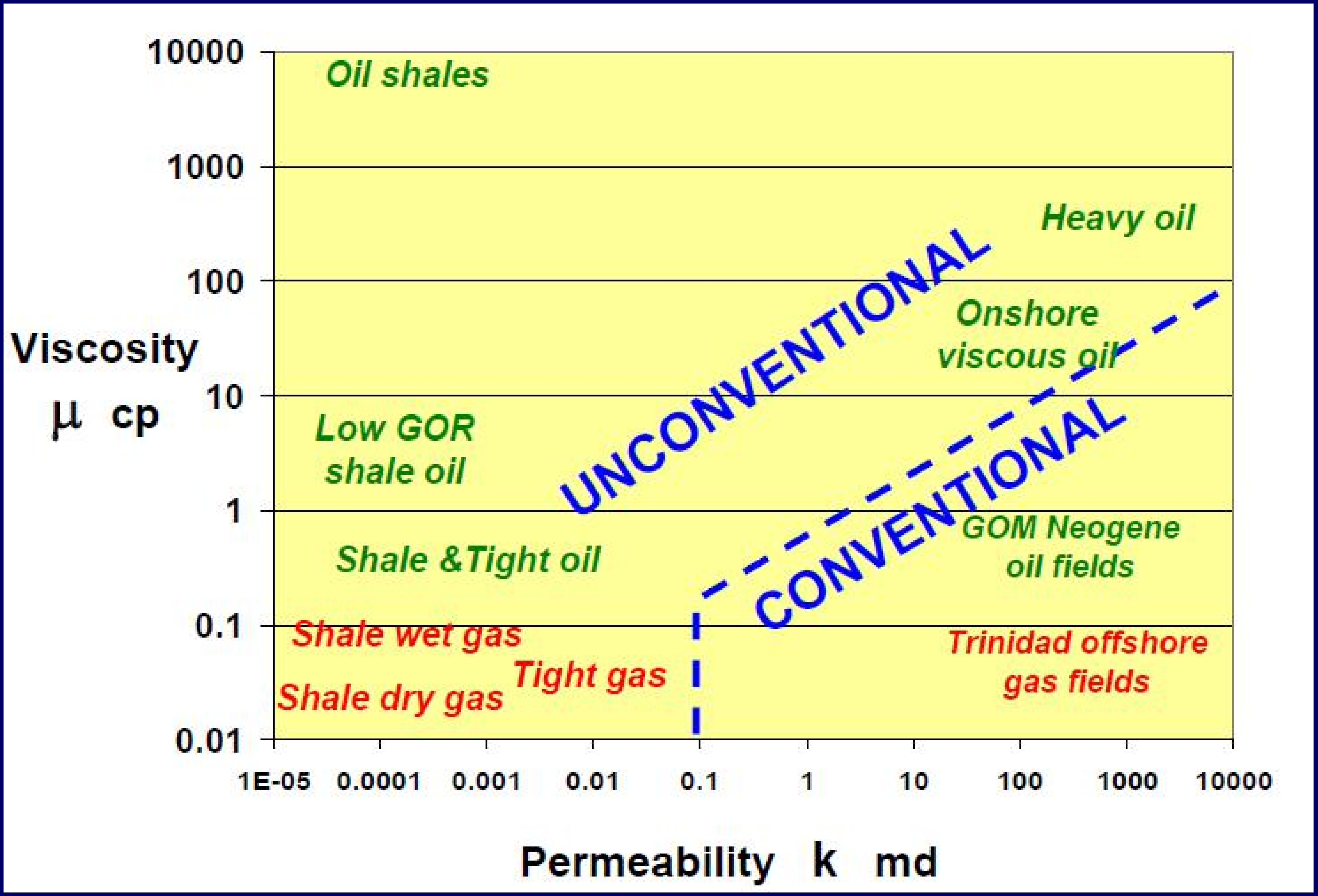


(modified from Holditch, JPT Nov. 2002)

Unconventional Natural gas (CBM, Tight Gas, Shale Gas)

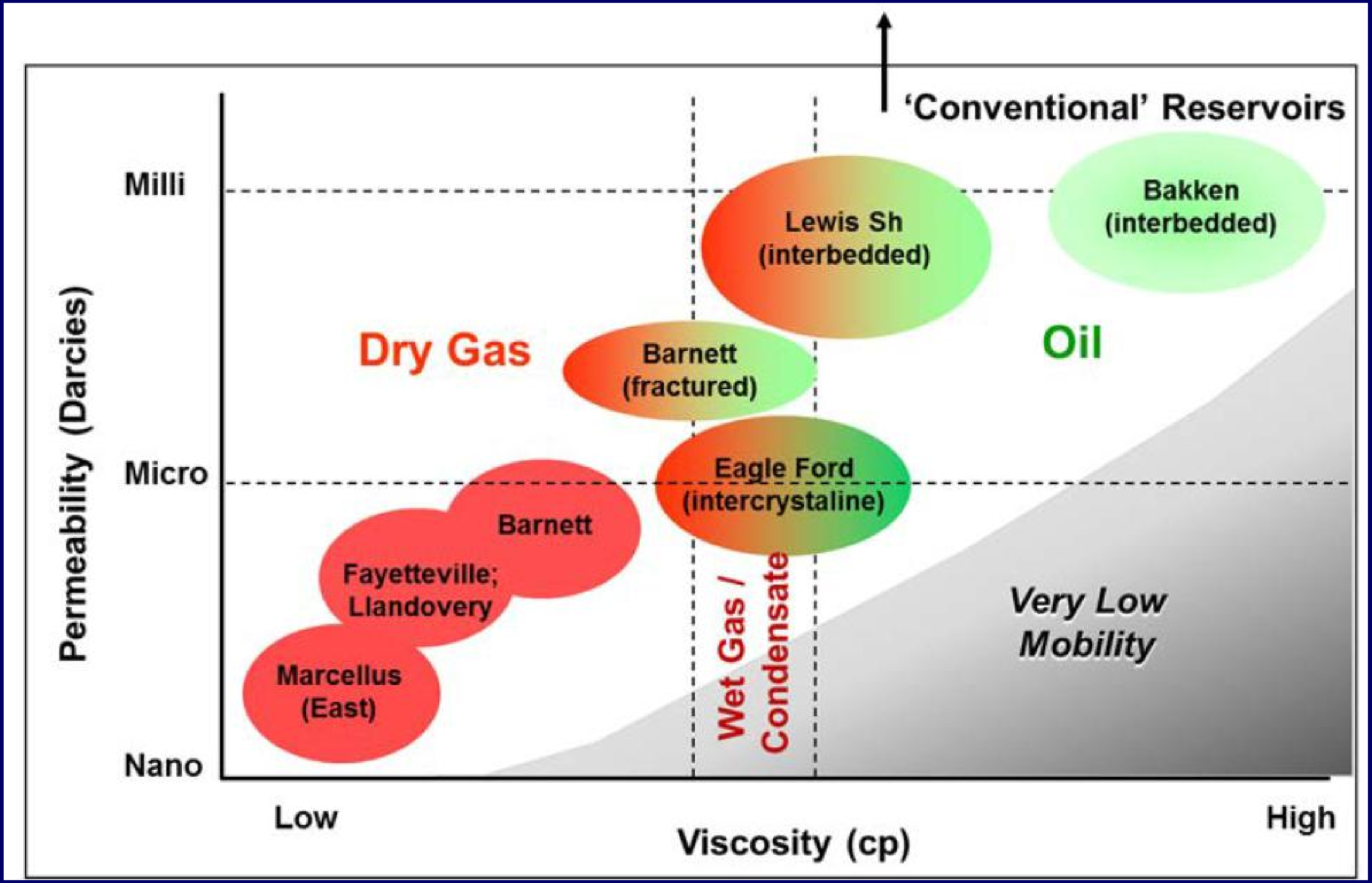
-Clean Energy Resources

New Definition of Unconventionals



H. Cander, 2012

Example of New Classification

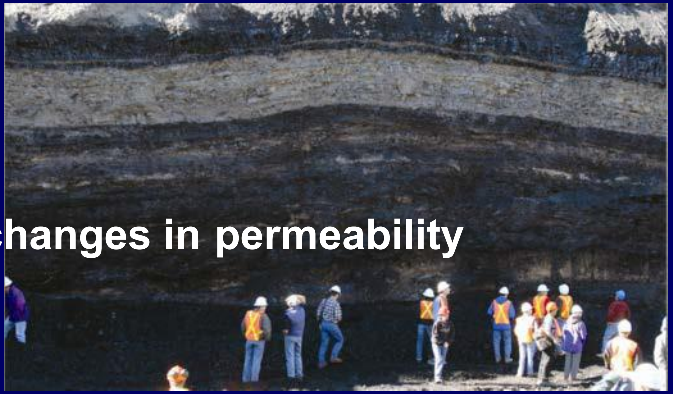


K. Bohacs, 2013

Types of Unconventional Reservoirs

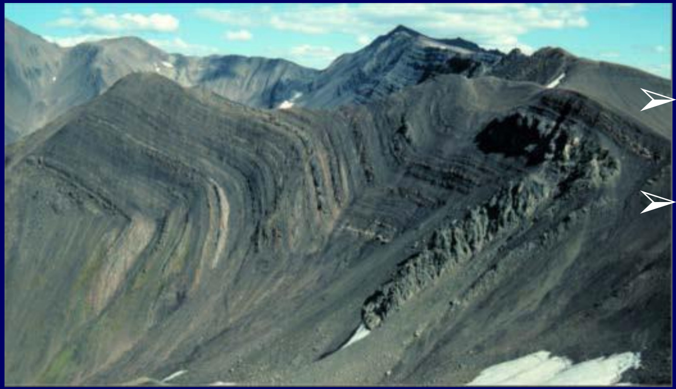
Tight Gas and Oil Sands and Carbonates

- Natural gas or oil has migrated into the micro-porosity of the rock matrix
- Commonly found in basin centered gas deposits



Natural Gas from Coal (Coalbed Methane)

- Host rock is both source and reservoir
- Reservoir rock is highly compressible and subject to changes in permeability



Shale Gas

- Very high natural gas resource base per volume of reservoir rock due to high micro-porosity
- Requires extensive fracture stimulation

Courtesy of CSUG

Reservoirs of Unconventional Plays

Conventional Gas Reservoir → Tight Gas and Oil Reservoir → "Hybrid" Reservoir → Shale Gas Shale Oil Coalbed Methane Reservoirs

The shift from conventional to unconventional reservoirs reflects a change in grain size from higher permeability and coarser grained rocks towards very fine grained rocks with low permeability

Reservoir variability both vertical and geographically can lead to the development of "sweet spots" of higher permeability in the finer grained reservoir rocks

Core photos courtesy of Canadian Discovery

Characteristics of Shaly Unconventional Reservoirs

Organic-rich Black Shale

- High TOC & high adsorbed gas
- Low matrix Sw
- High matrix Sg
- Gas or Oil stored as free & adsorbed
- Mature Source Rock

Silt - Laminated Shale or Hybrid

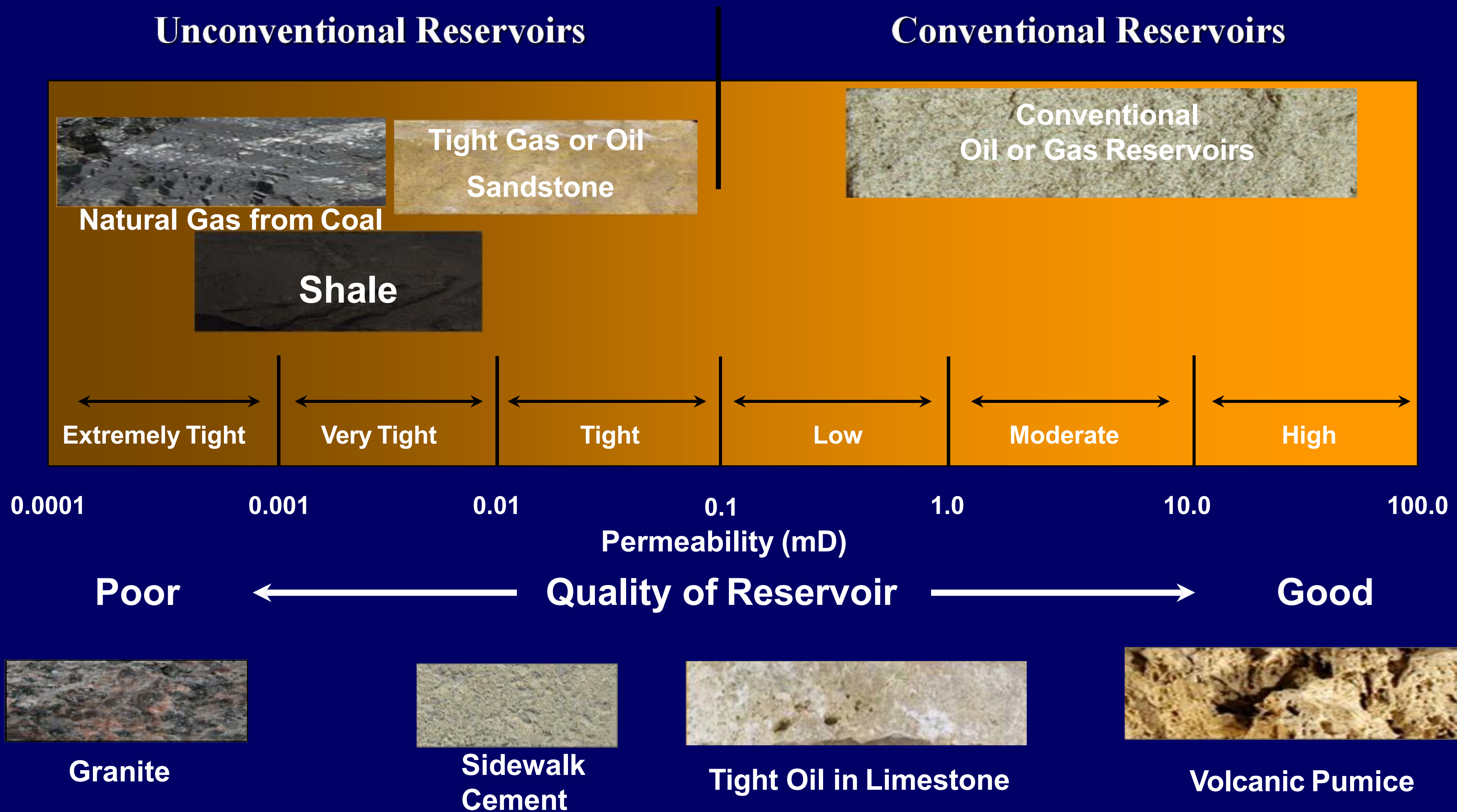
- Gas or Oil stored in shale and silt
- Low to moderate TOC
- Higher permeabilities in silty layers

Highly Fractured Shale

- Low TOC & low adsorbed gas
- High matrix Sw
- Low matrix Sg
- Gas stored in fractures
- Shale is the source rock

From Hall, 2008

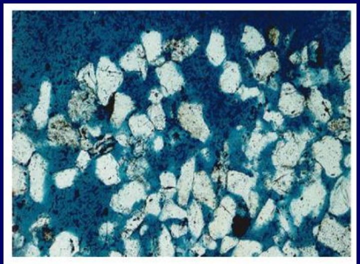
Summary of Unconventional Reservoirs

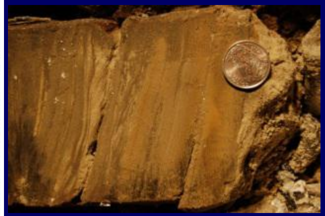


Note: Natural Gas from Coal reservoirs are classified as unconventional due to type of gas storage

modified from US DOE

Conventional to Unconventional Geology-Pore Space

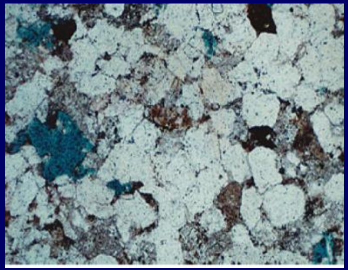




Deltaic and deepwater reservoir

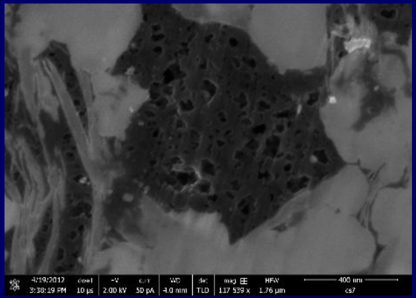
Frontier areas in Arctic,
GOM, Atlantic margins,
South China Sea,
W SE Asia active margin

Conventional reservoir



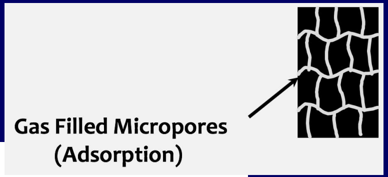
Unconventional
tight gas reservoir (Piceance and Ordos)

Unconventional
tight shale gas reservoir
(inorganic+organic pores)

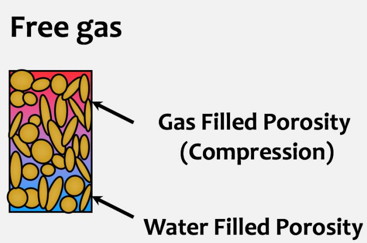


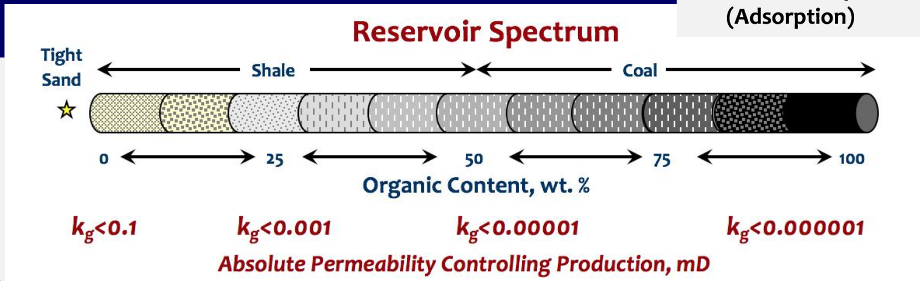
Focus now and fugure: Marcellus,
Utica, Longmaxi, Niobrara,
Vaca Muerta

Pore size,
pore throat,
Permeability
decrease

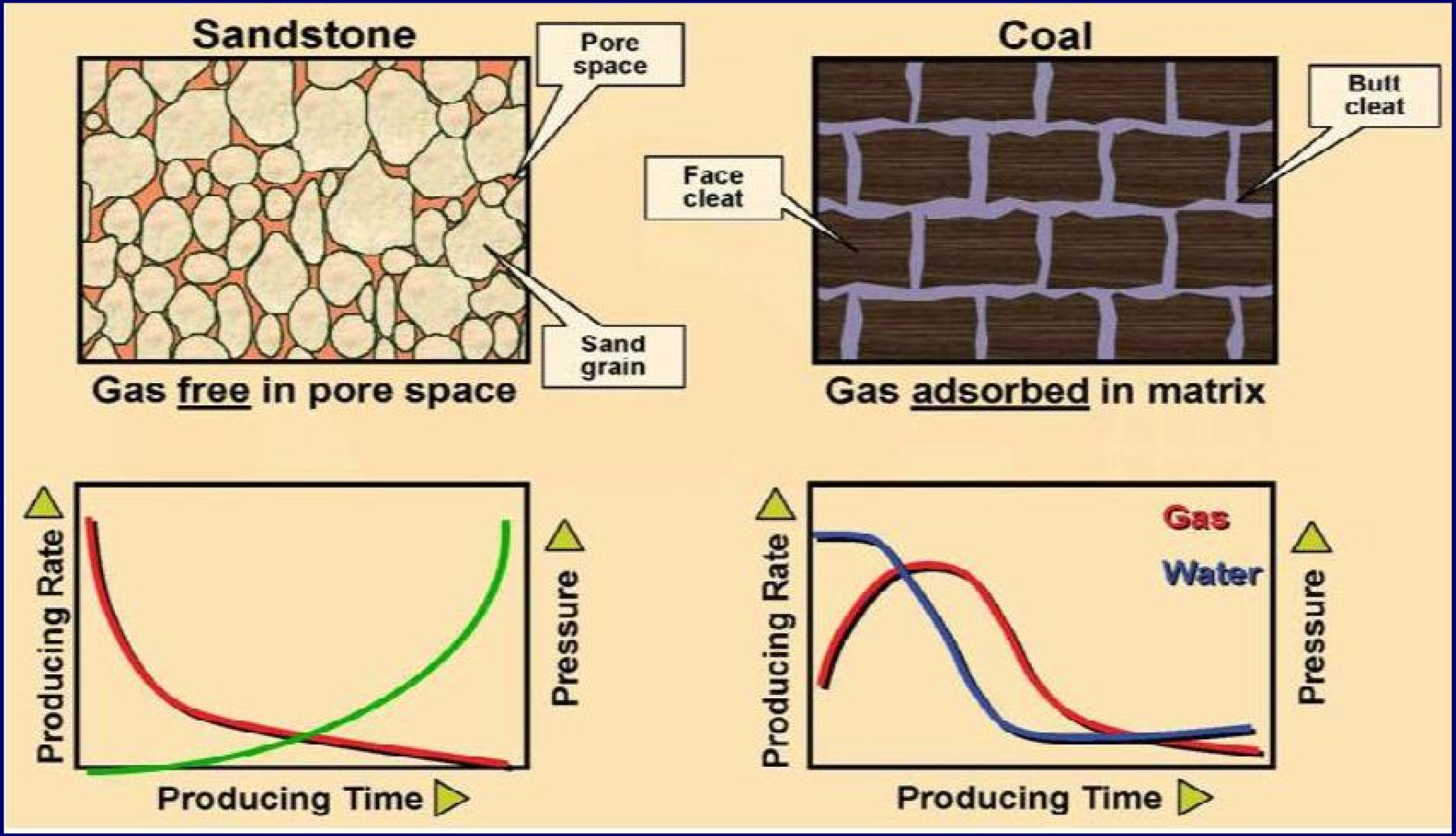


Unconventional
CBM reservoir
(organic adsorption)



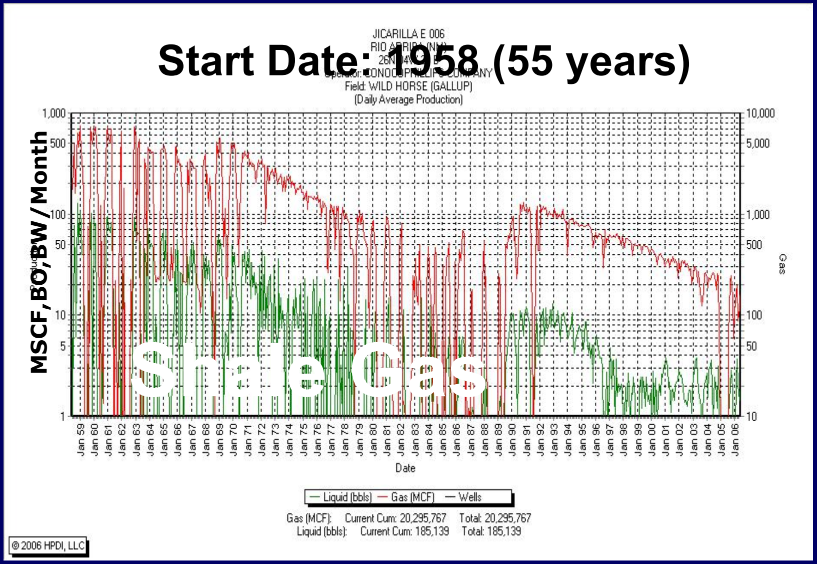


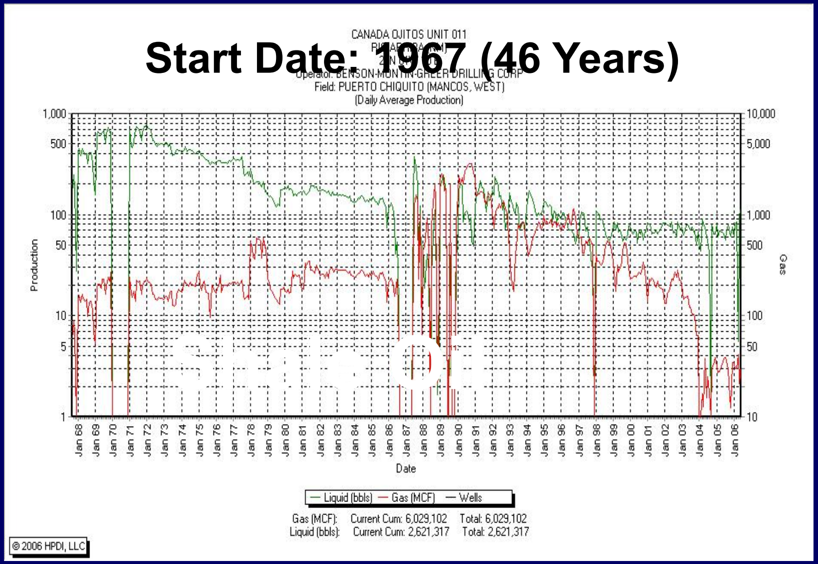
Different Reservoir Mechanisms



Why are Tight Reservoir Plays Important

- Low risk development projects
- Long term production
- Examples of "Shale" in the San Juan Basin, USA

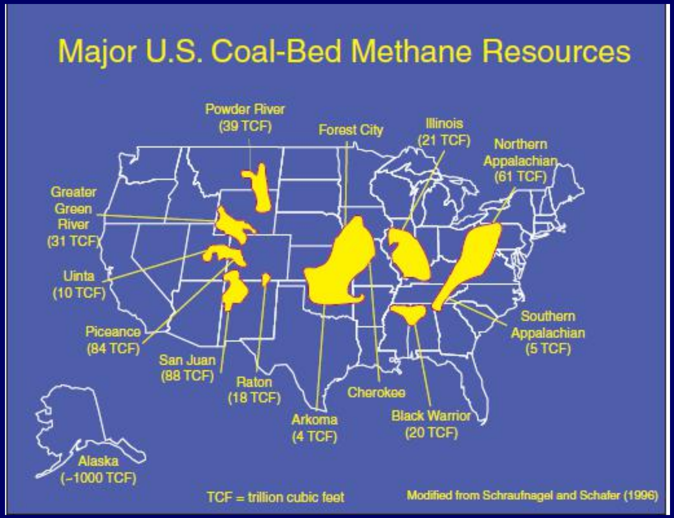




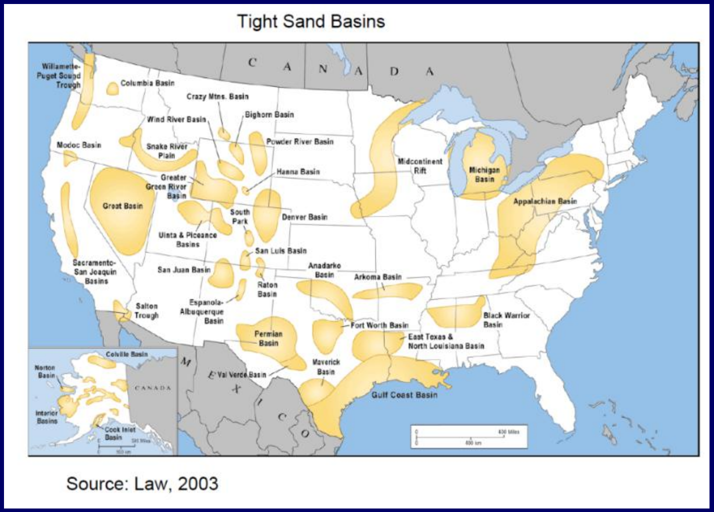
Cumulative Production:
over 20 BSCF and 185 MBO
in 55 years

Cumulative Production:
over 2 BSCF and 2,600 MBO
in 46 years

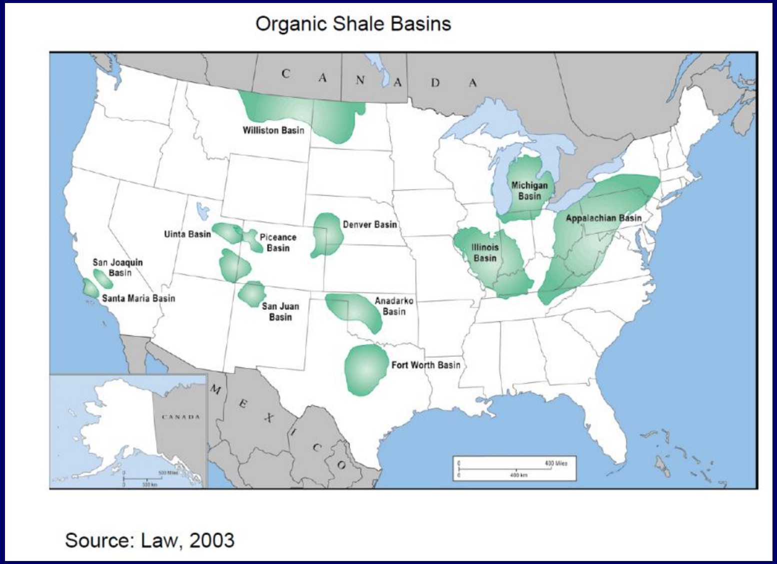
Unconventional History

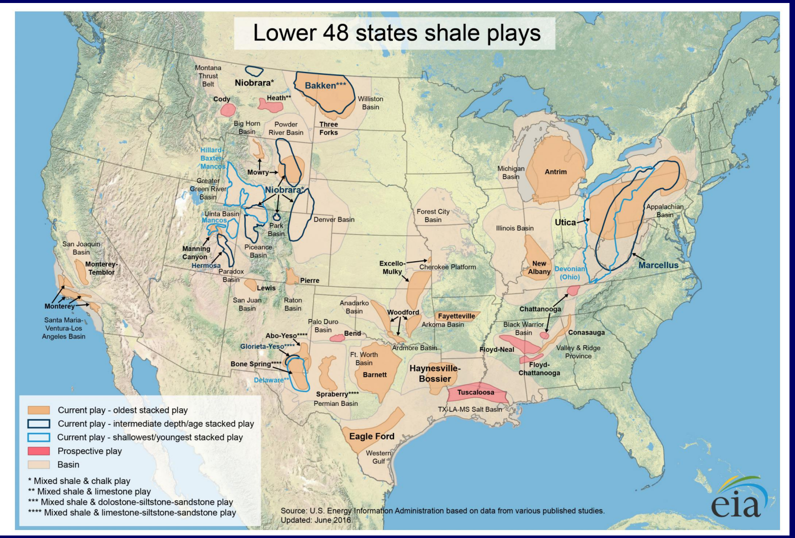


CBM Plays, 1996



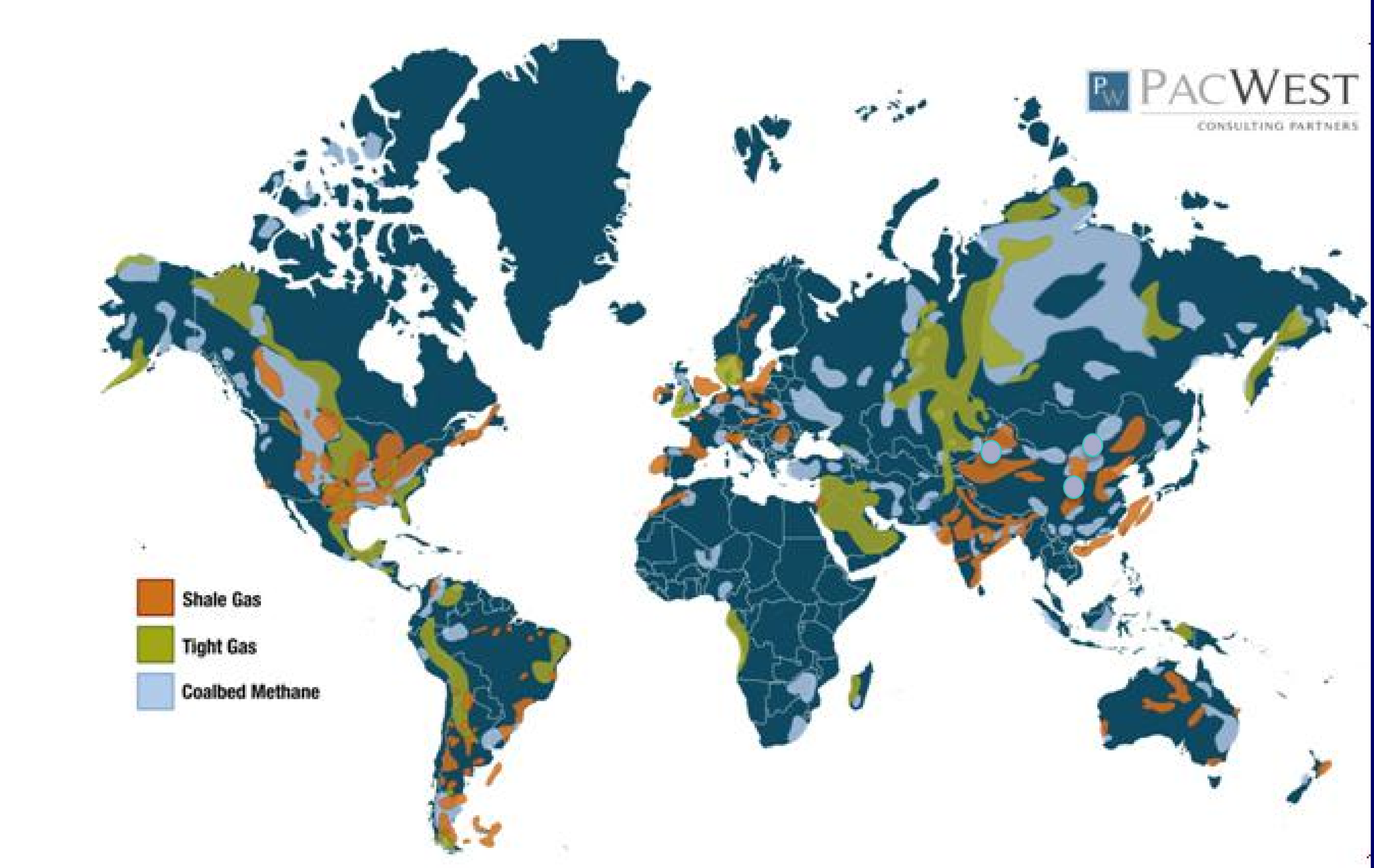
Tight Gas Plays, 2003



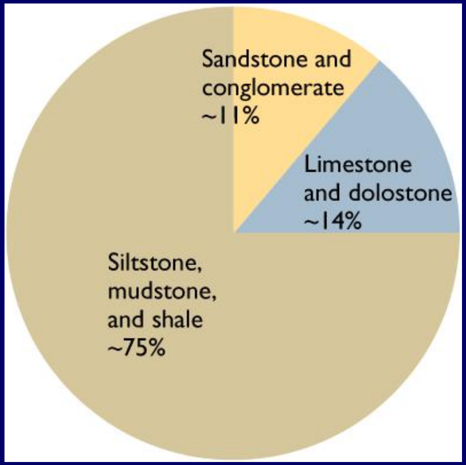


Shale Plays (2003 to 2016),evolves fast, shale gas revolution driven by technology

Major Unconventional Gas Plays in the World



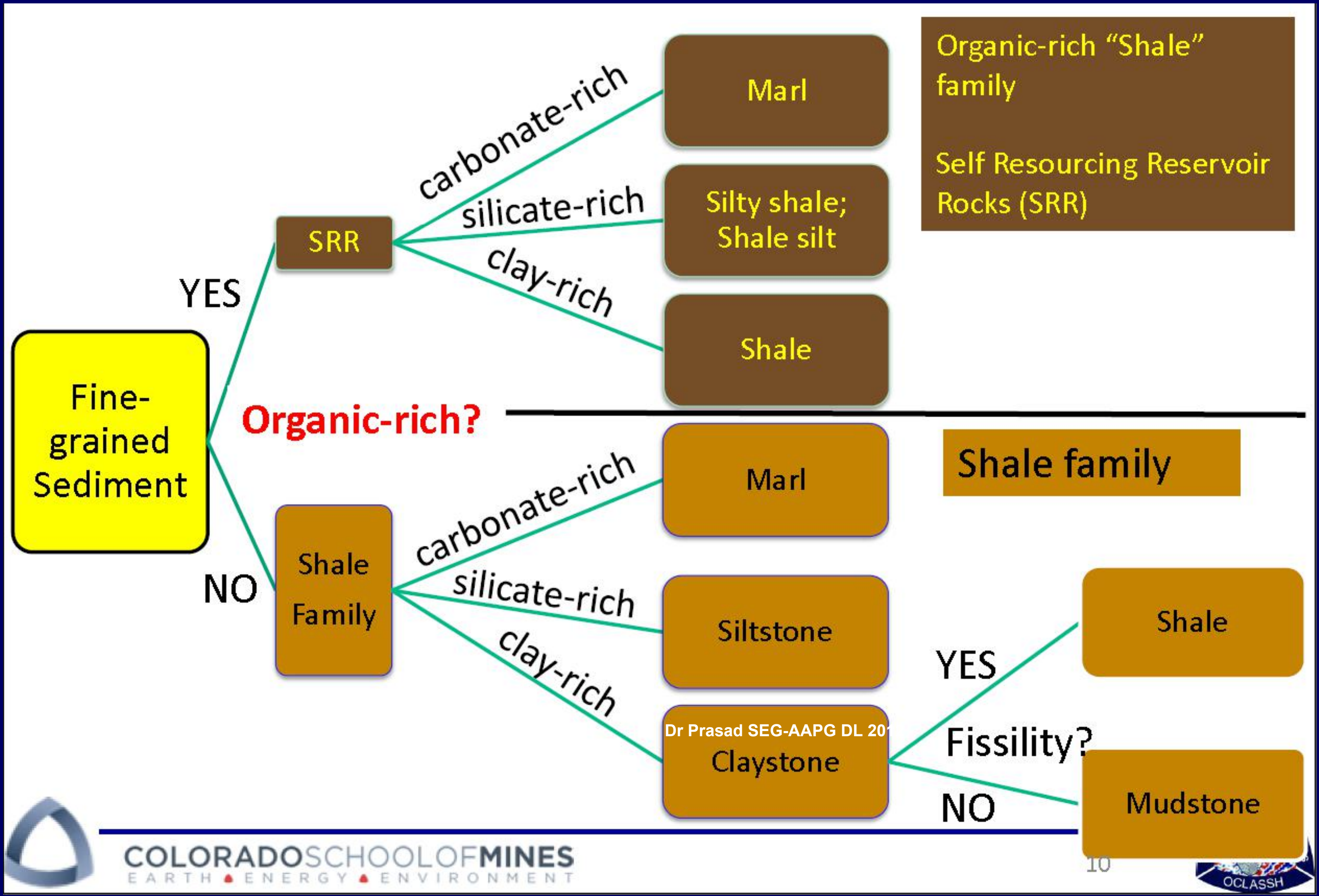
Definition of Shale



Shale is a fine-grained sedimentary rock whose original constituents were detrital material, clays and/or organic material. It is characterized by thin lamina, often splintery, and parallel to the often indistinguishable bedding planes. These are better called Mud Rocks.

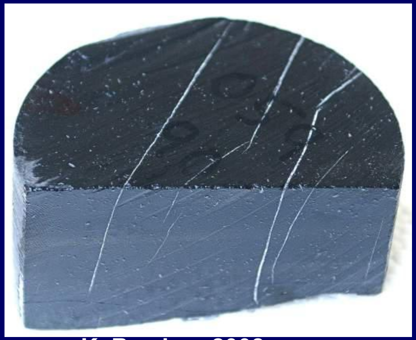
Fine-grained sediments

“Shale” Classification



New Understandings of Shale Facies

Barnett Siliceous shale



K. Bowker, 2008

Eagle Ford
carbonate rich shale

L Green River shale
with ostracod grainstone

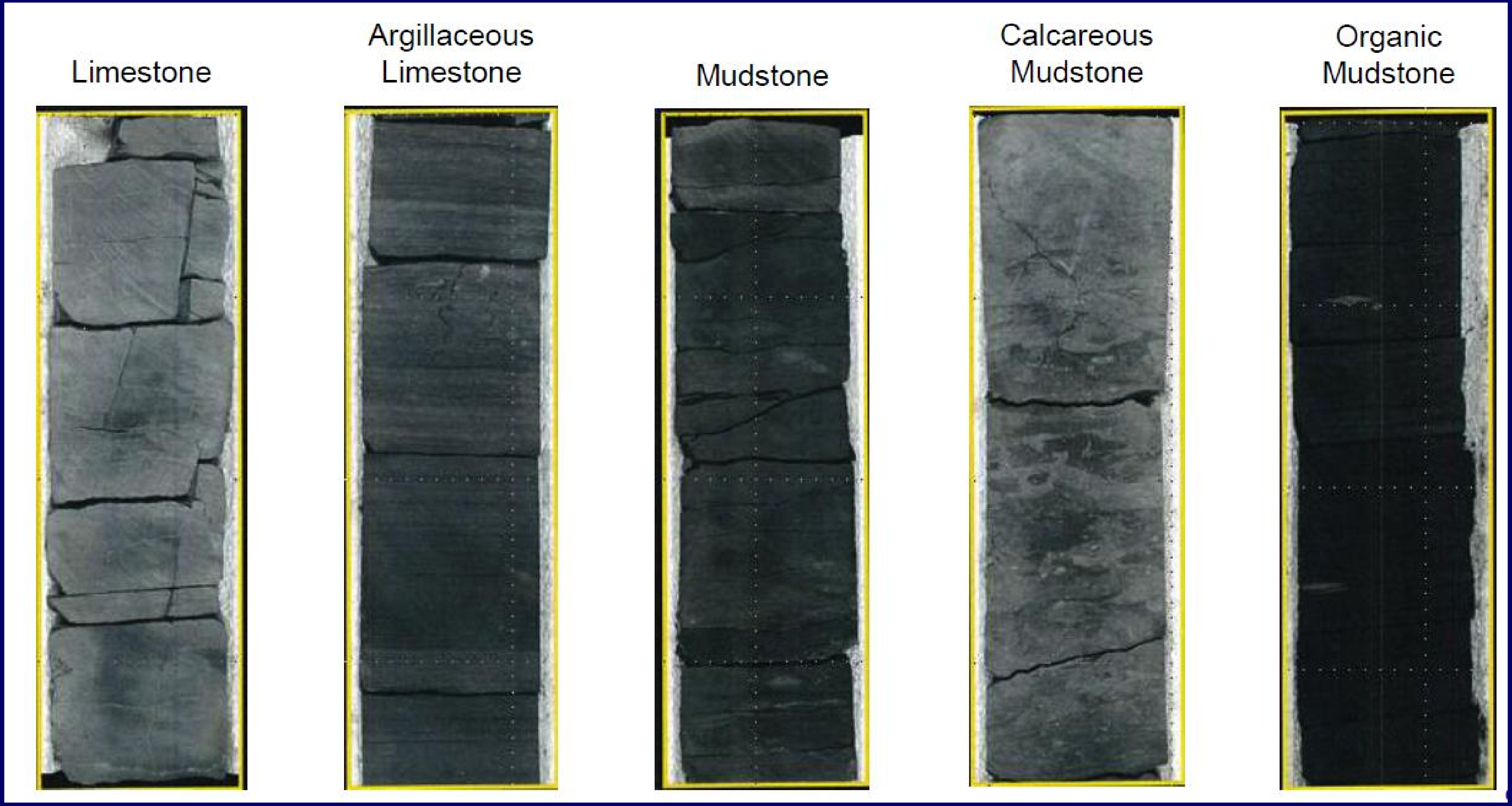
Niobrara chalk
(Primary reservoir)

Niobrara marl

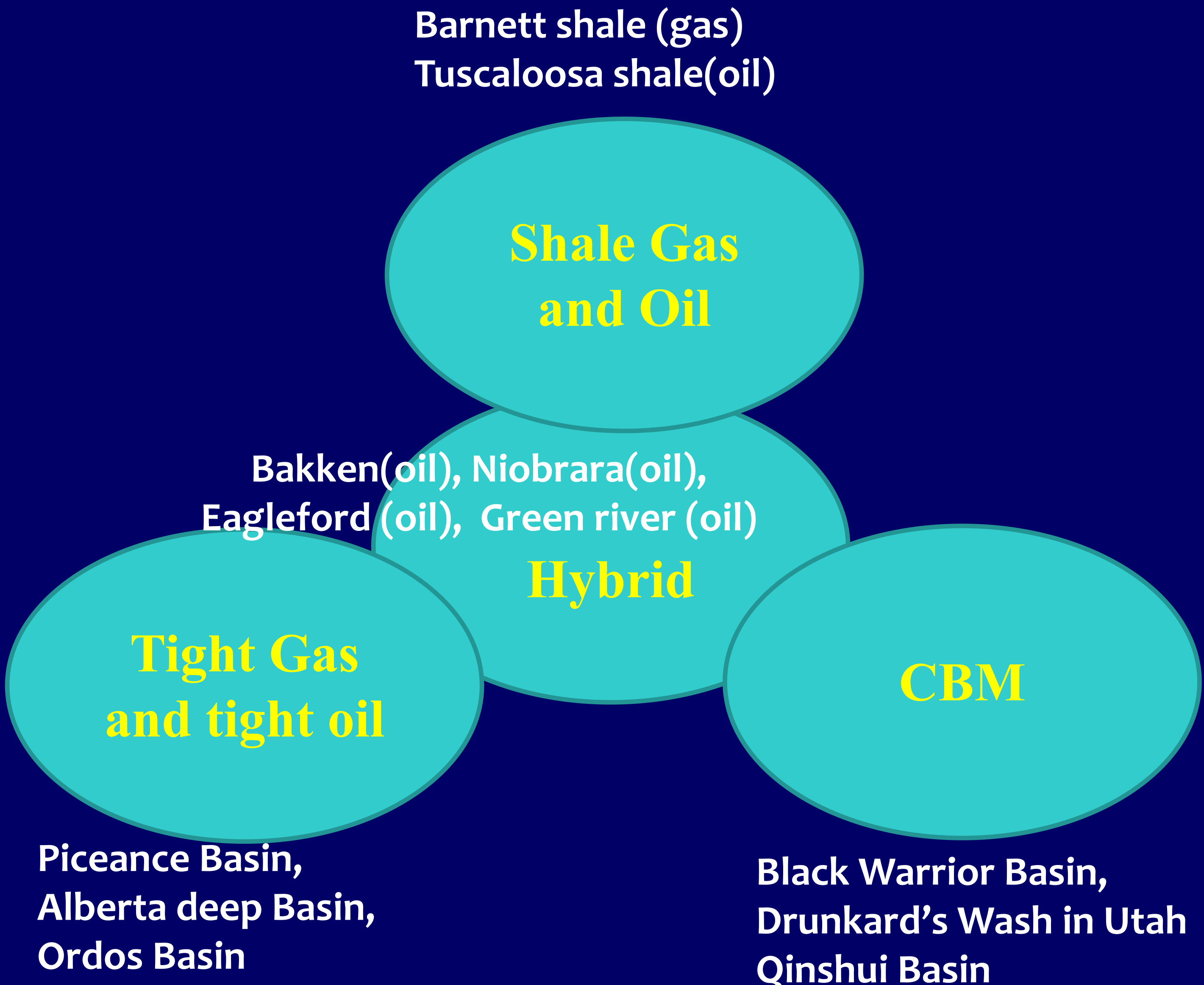
Bakken dolomite
(Primary reservoir) and shale

Hybrid Lithofacies –Hybrid Plays
shale+fine-grained organic-lean tight reservoir

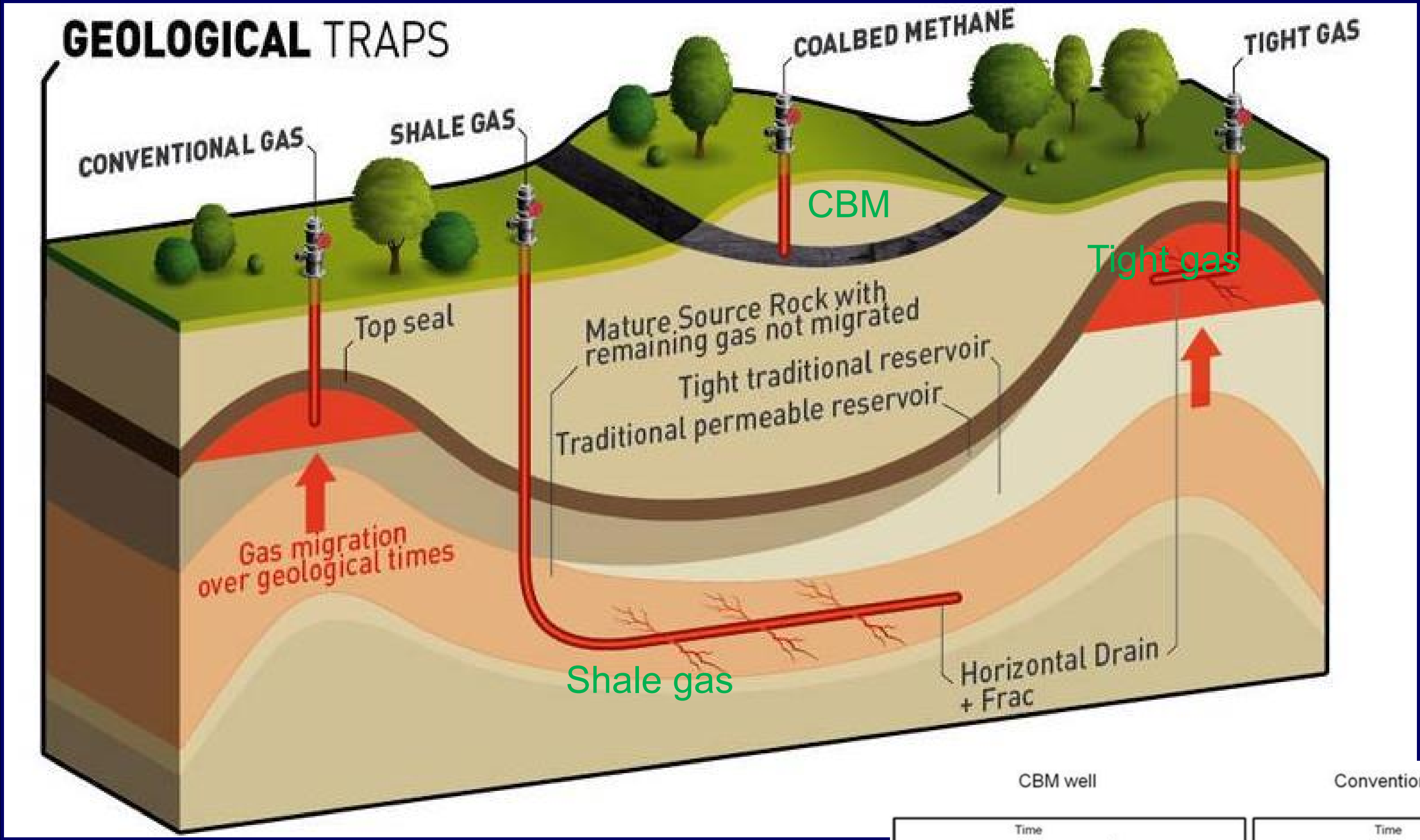
Different Lithofacies for One Shale



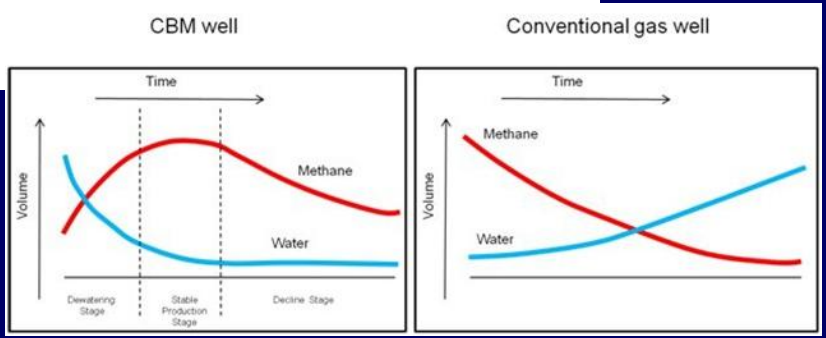
Unconventional Tight Reservoirs



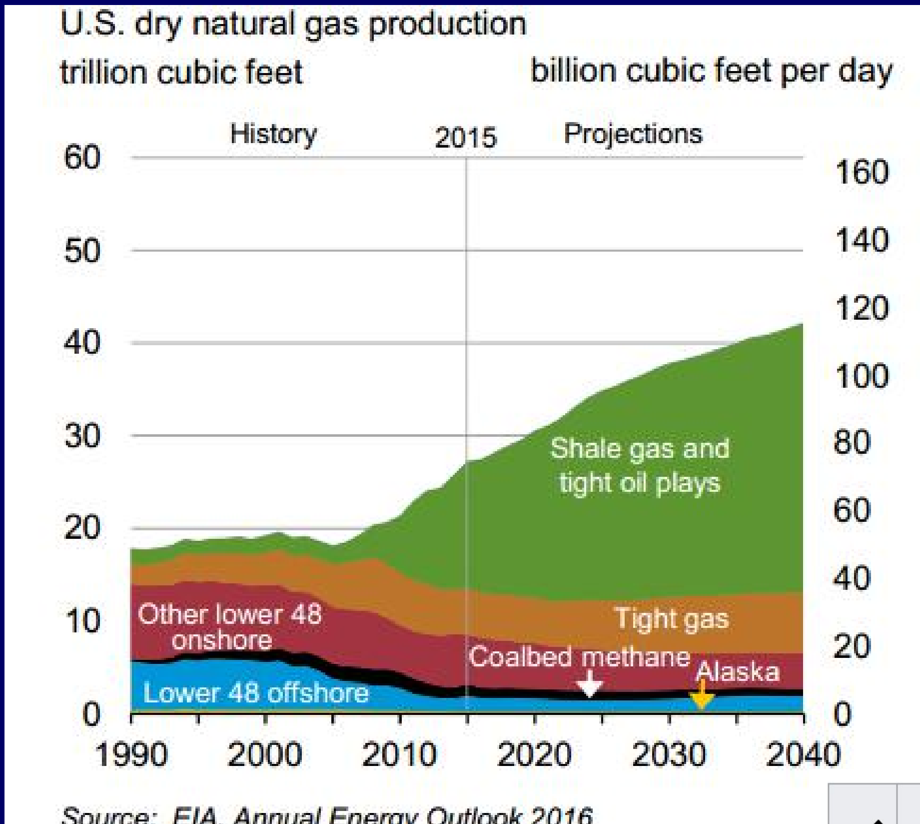
How Unconventional Gas is Produced?



From various resources



CBM, Tight Gas to Shale Gas



Clean CBM and Tight Gas-decreasing

Clean Shale Gas-US Shale Gas Revolution

Energy Revolution in U.S.

Decreased Energy Prices

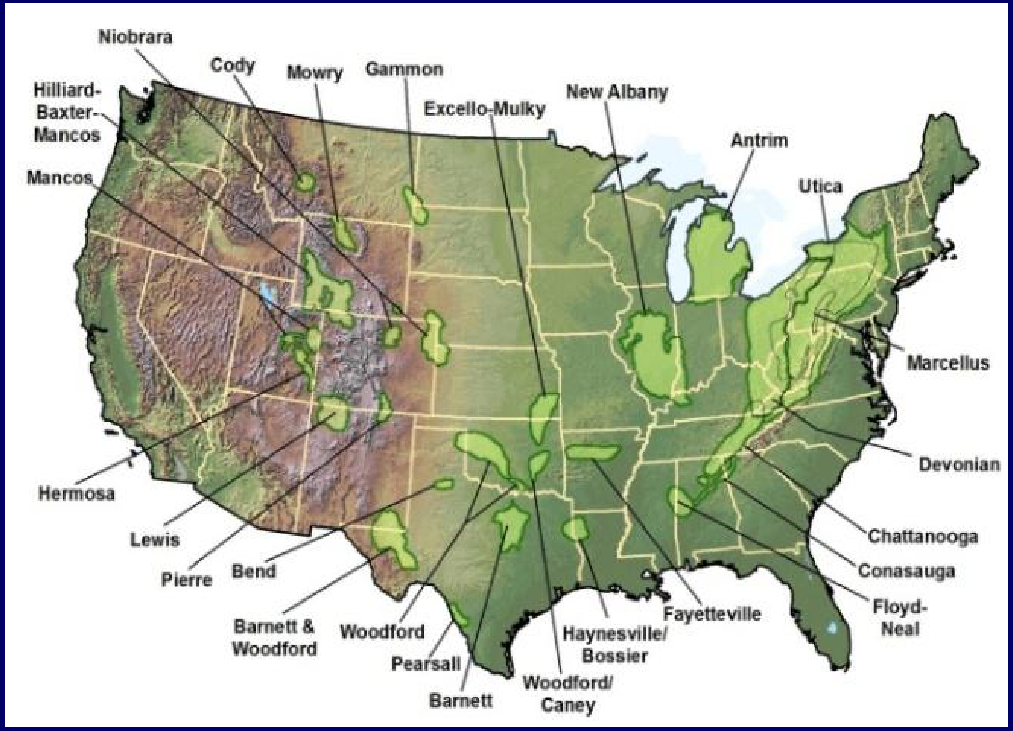
Increased Economic Activity

Increased Government Revenues

Reduced Emissions

	Country	Oil Production (bbl/day)[1]	Oil Production per capita (bbl/day/ million people)[5]
-	World Production	80,622,000	10,798
01	United States[6]	11,300,000	27,549
02	Russia	11,200,000	73,292
03	Saudi Arabia (OPEC)	10,460,710	324,866
04	Iraq (OPEC)	4,451,516	119,664
05	Iran (OPEC)	3,990,956	49,714
06	China	3,980,650	2,836

Historical Perspective



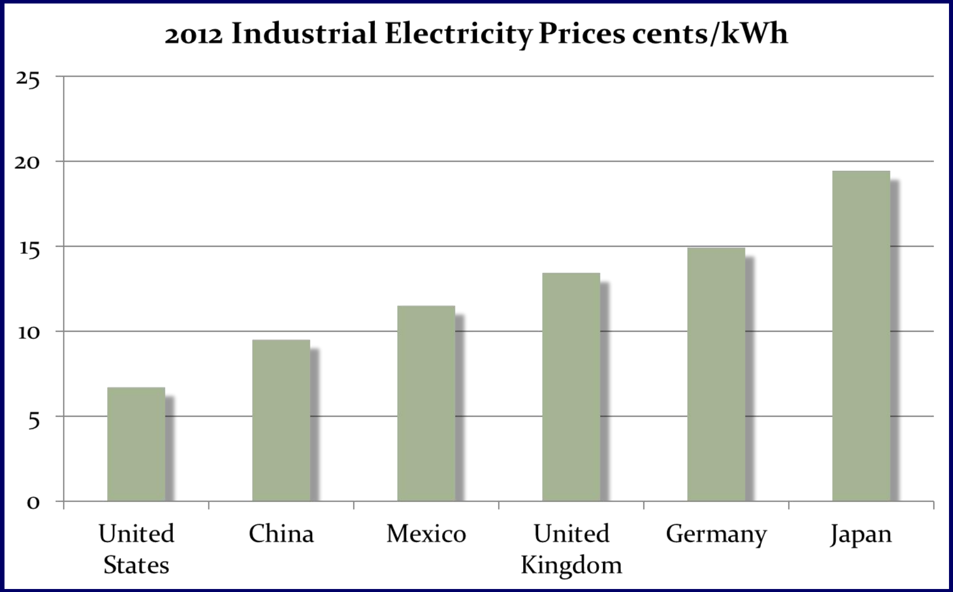
Gas from unconventional resources has been a major focus in the USA for several decades.

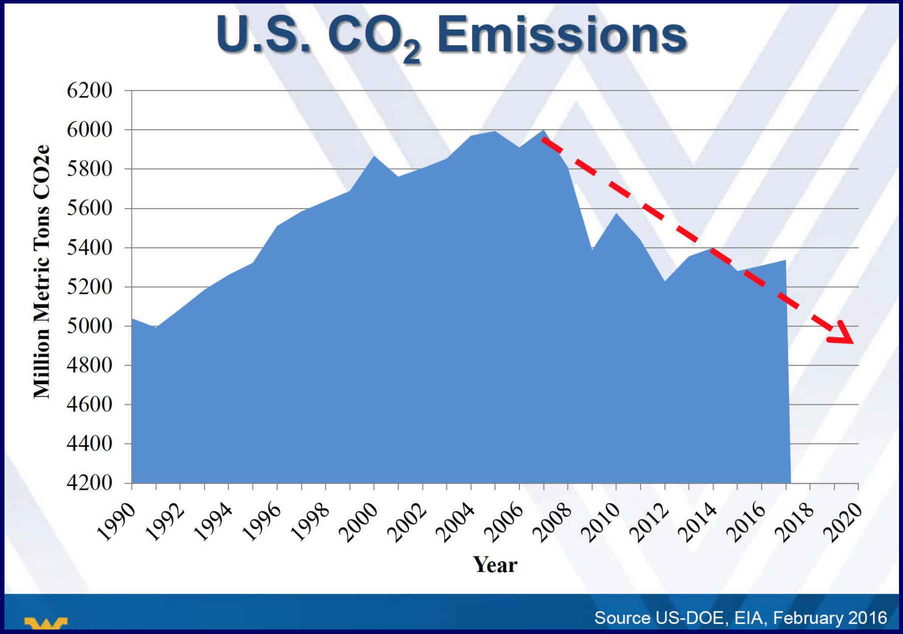
- 1970s-1990s: coal bed methane
- 1980s-1990s: shallow gas shales
- Post 1990's: deeper gas shales: Barnett,….., Haynesville,….
- Post 2000: shale liquids

Shale Exploration History

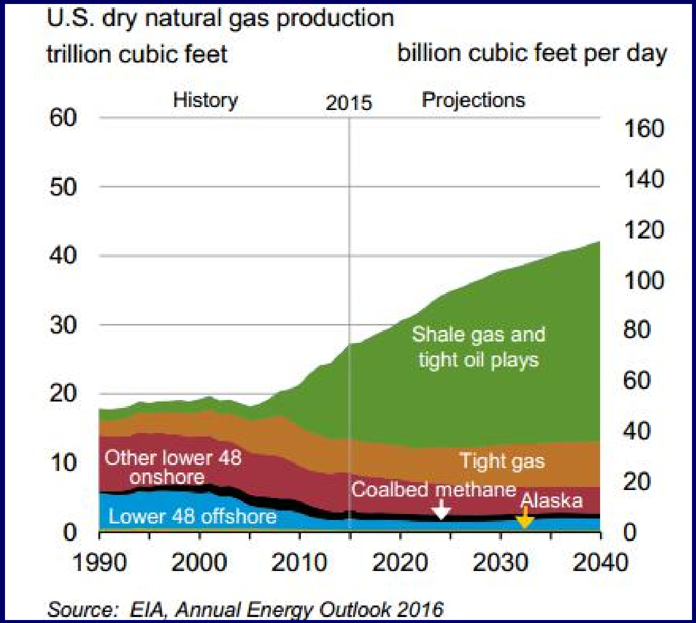
- 1st commercial gas shale well was drilled in New York in the late 1820s – nearly 40 years before Colonel Drake drilled his famous oil well in Pennsylvania.
- 1880's to 1980's-Local niche market, vertical wells and natural fractures: Appalachian Marcellus shales
- 20th century: shales=SR and seal for conventional
- Late 80's to 90's-Naturally fractured production from Antrim, Bakken, 1st phase of Barnett
- Late 1990's to 2000's-hydraulic fracture completions in Barnett, Haynesville, Fayetteville, etc. **Shales can be reservoirs.**
- Global assessment of shales from regional scale to nano-scale and technology improvement

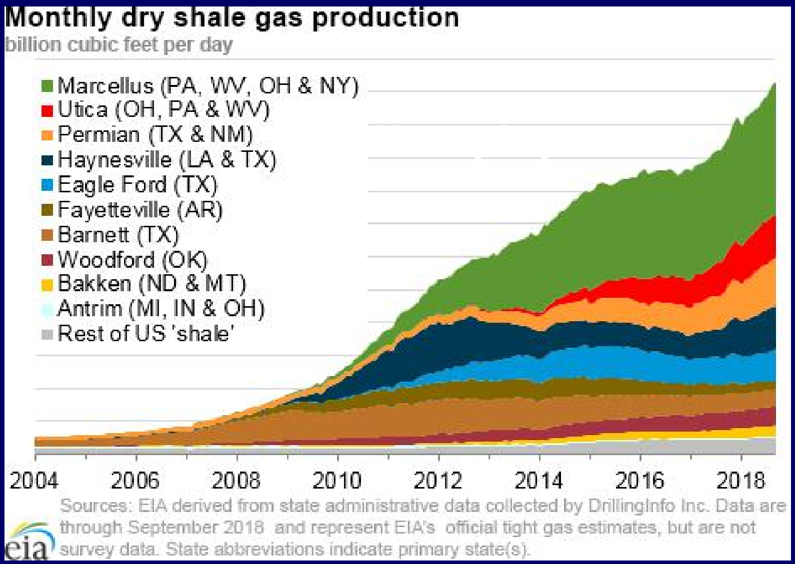
Benefits of Shale Gas Revolution





US Shale Revolution





Energy Revolution

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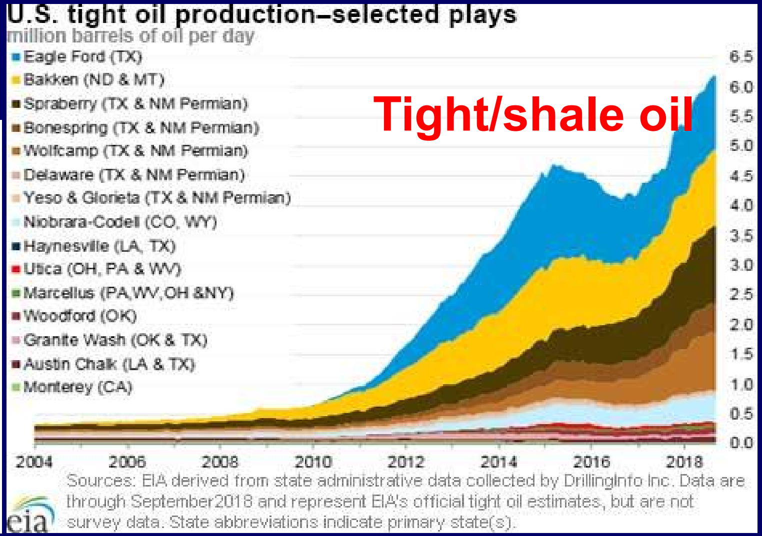
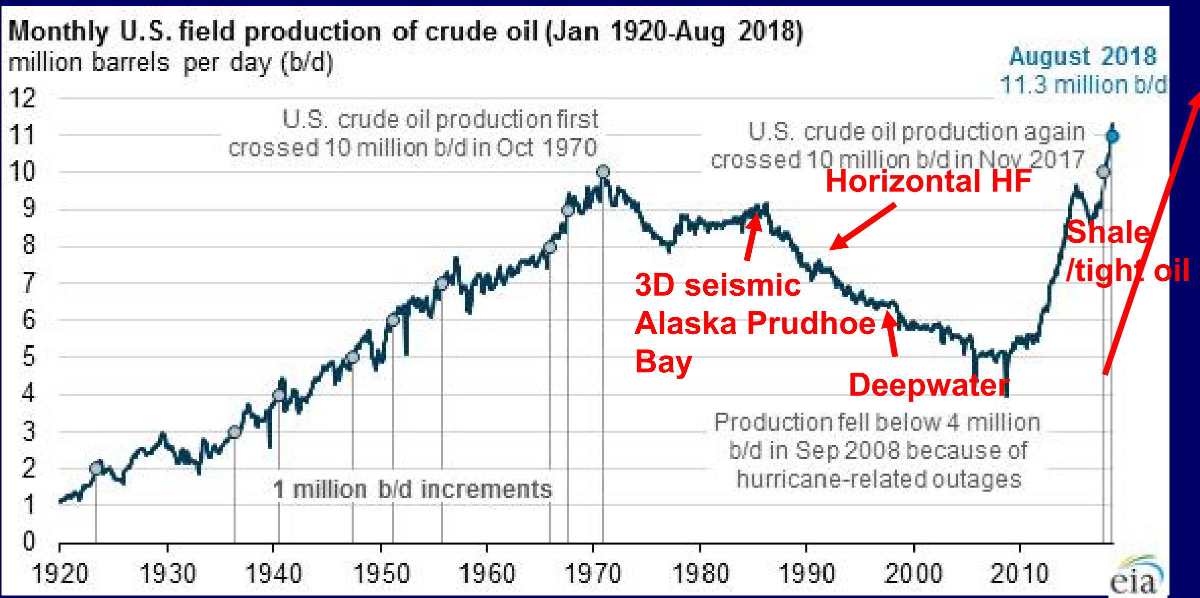
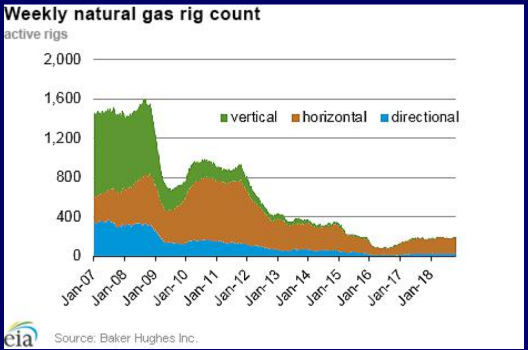
07	[illegible]	[illegible]	[illegible]



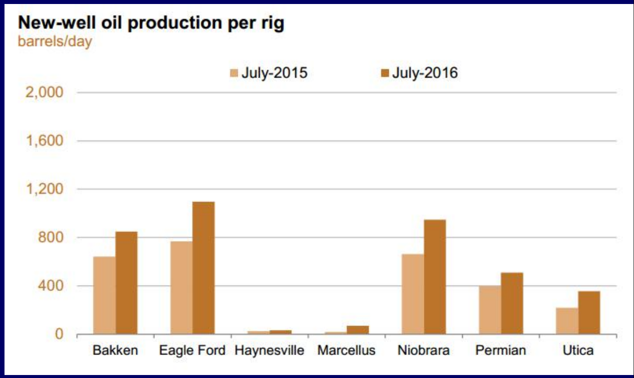
New plays

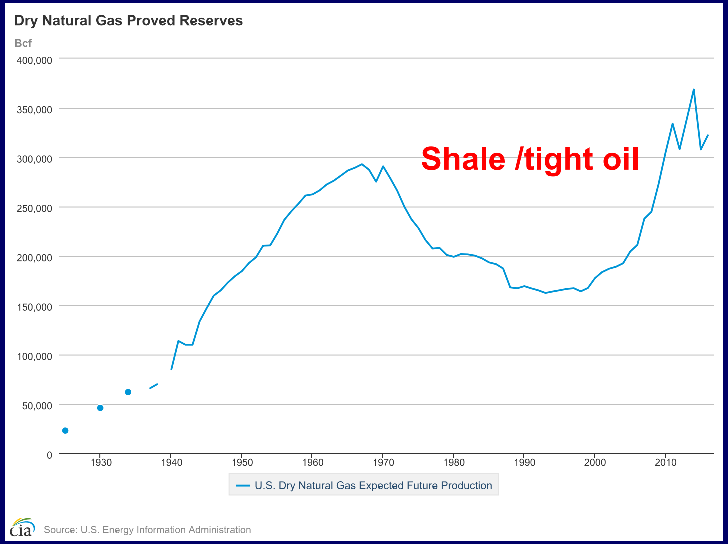
Lessons from History and Current of Production





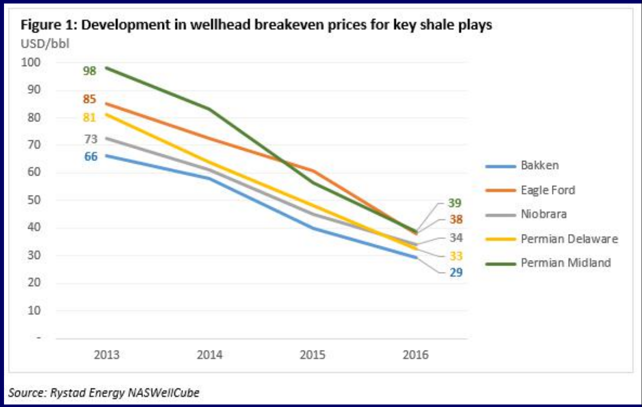
Horizontal well results in high production from fewer wells



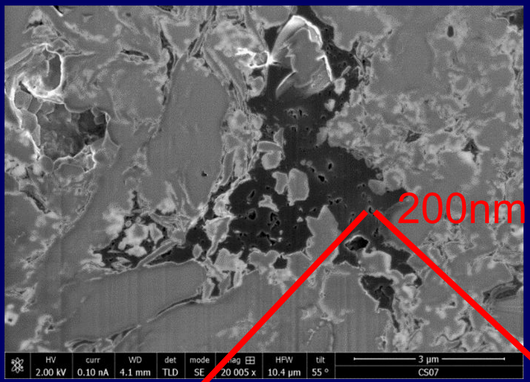


Both oil and gas production surpassed 1970 peak due to development of shale Plays

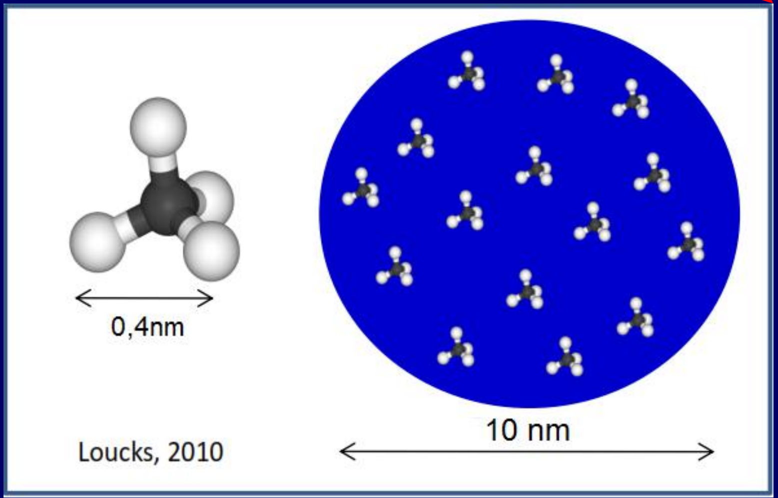
Low cost to develop shale resources

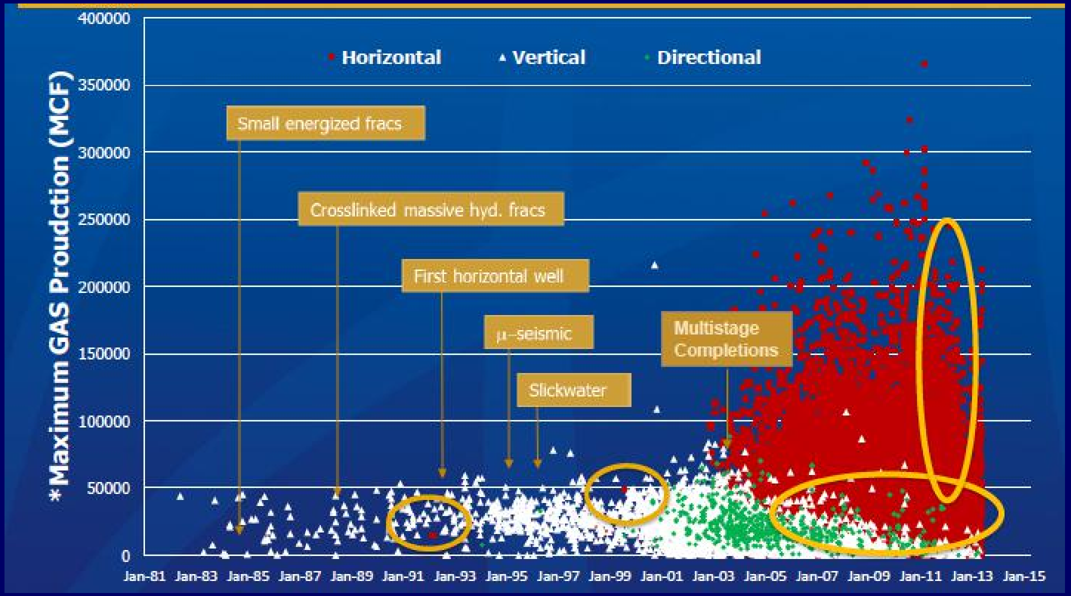


Shale Gas Revolution-Driven by Geological Understanding and Engineering Technology



Nano-pores can store huge amount of gas



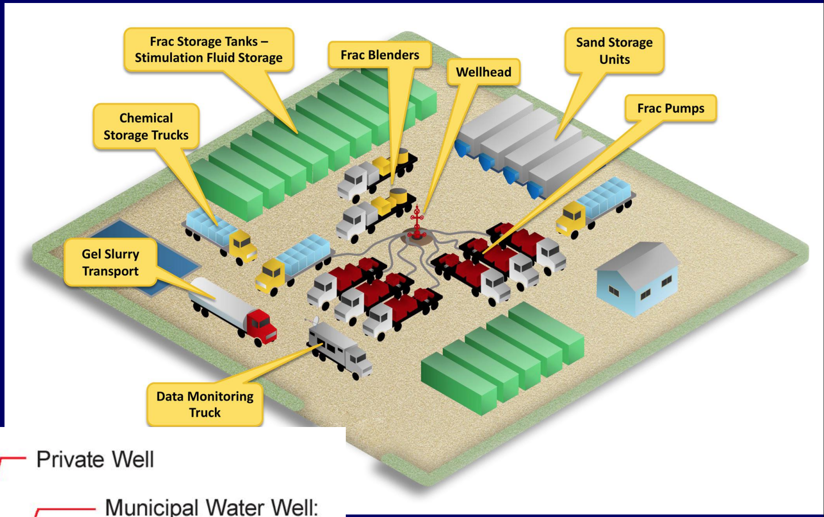


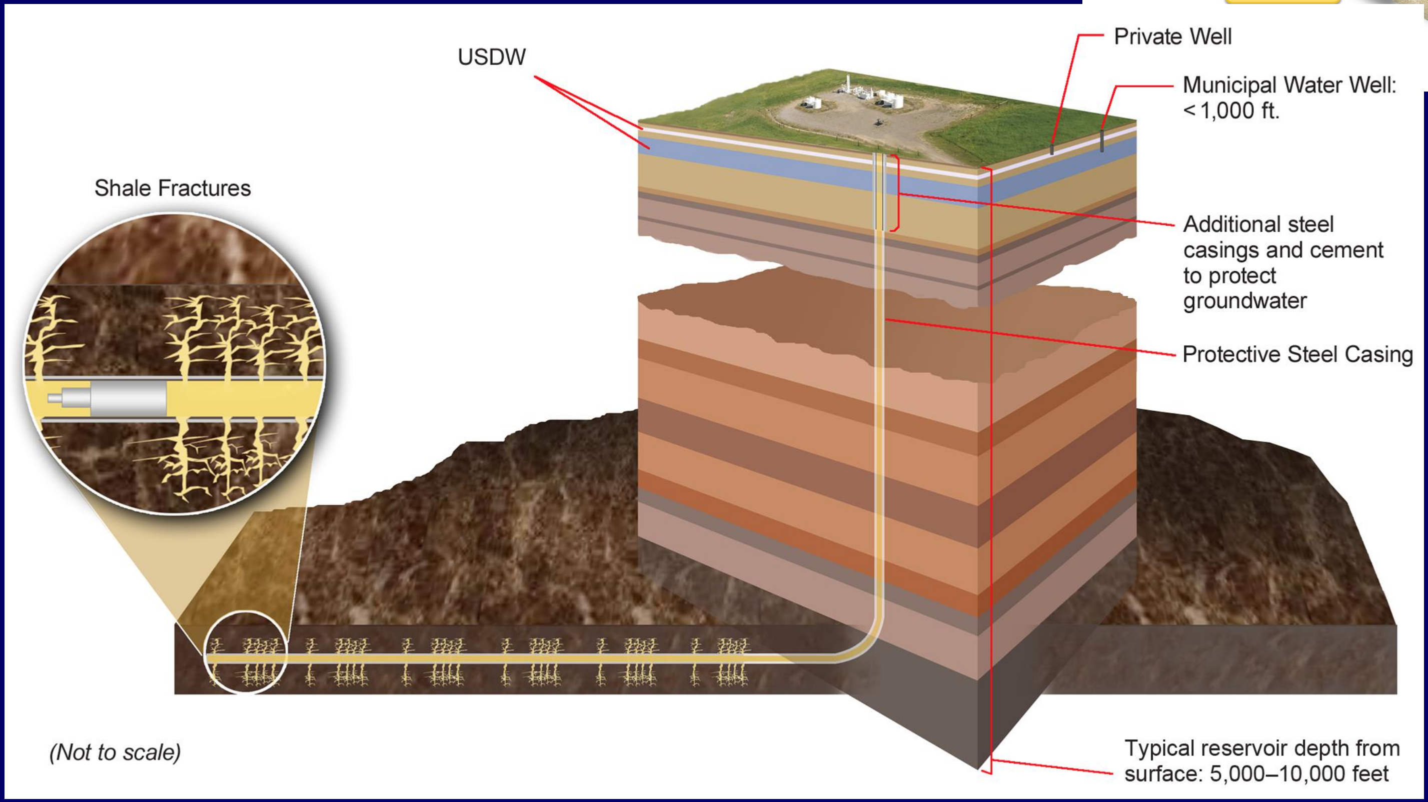
Gaffney & Cline, 2013

Geology:
organic-rich shale can be reservoir
Engineering:
slickwater + horizontal drilling+ hydraulic fracturing

Hydraulic Fracturing in Horizontal Shale Well

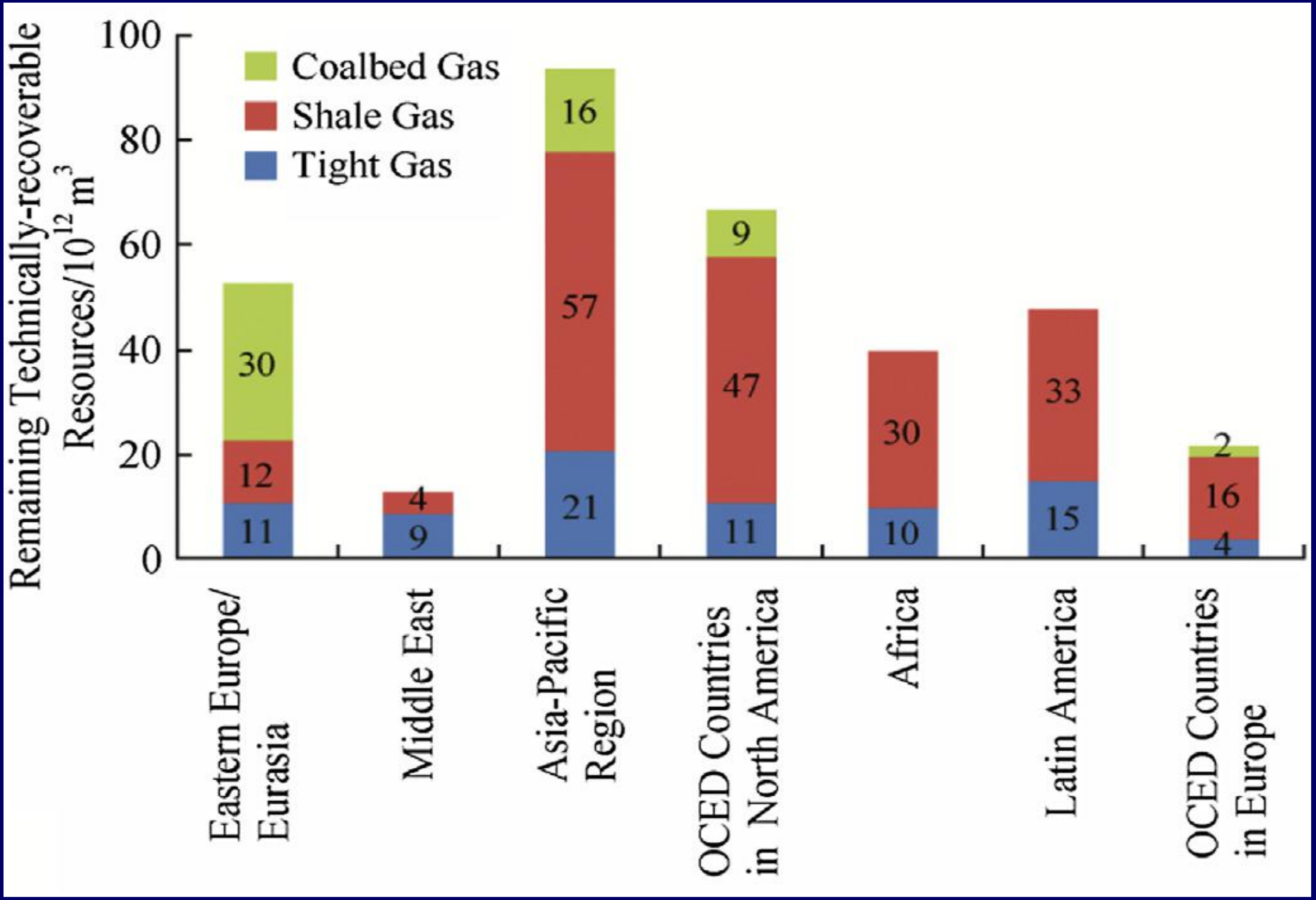
Man-made fractures to release natural gas trapped in tight shale reservoirs





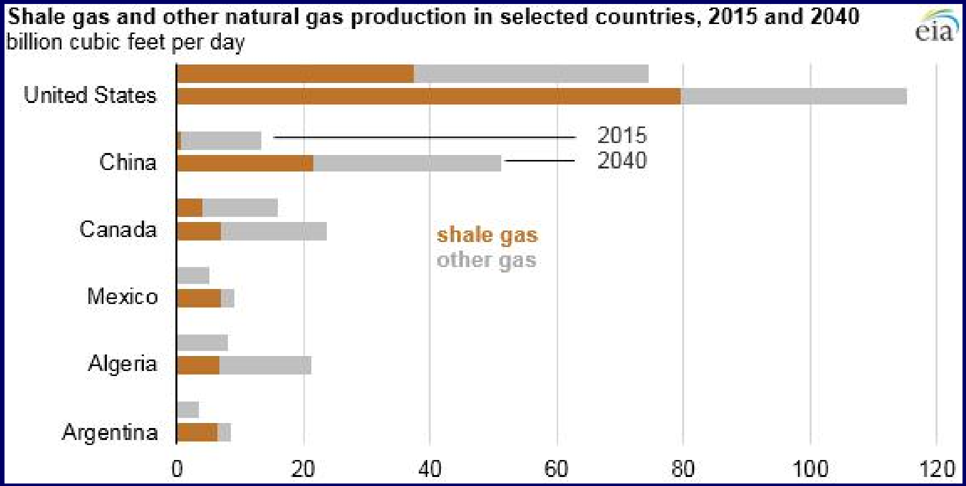
From EIA

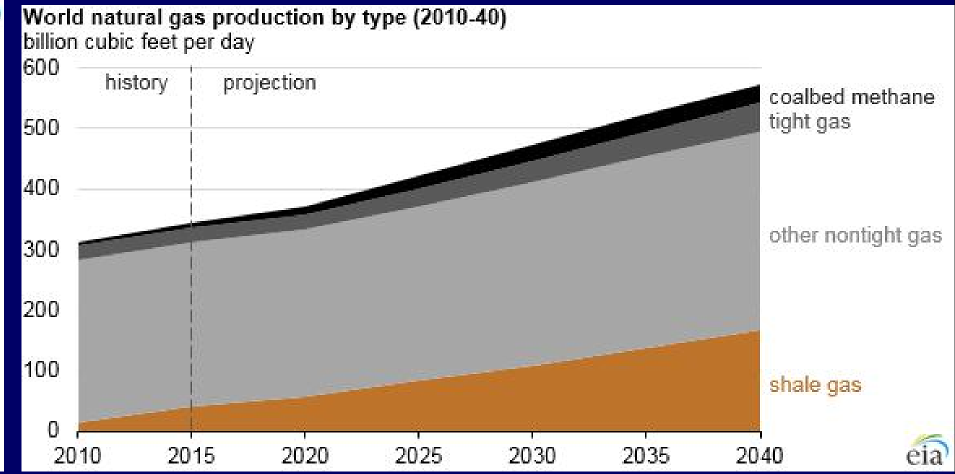
Global Unconventional Gas Resources

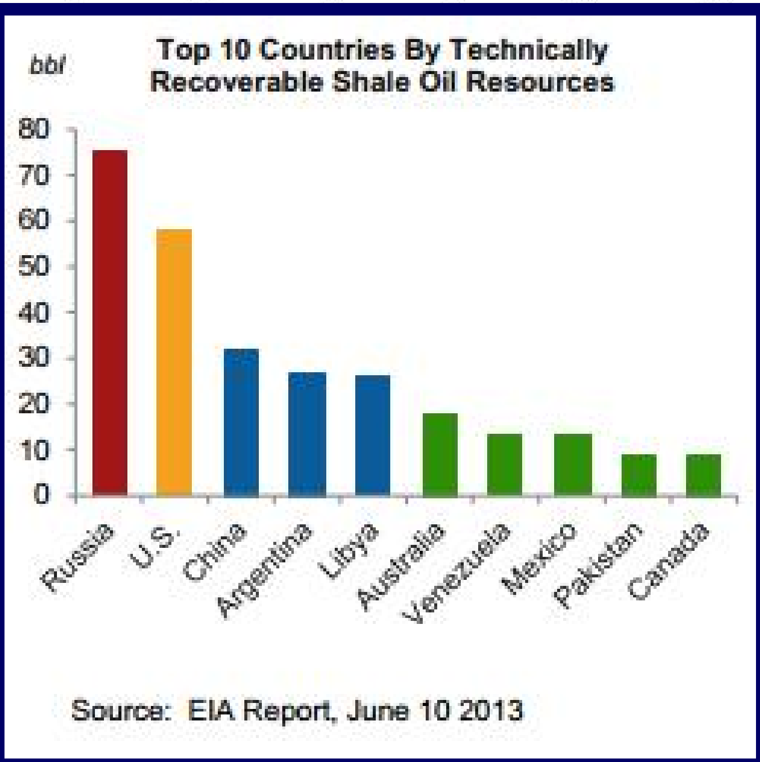


Data from USGS

Future Shale-related Resources Production Countries







United States

China,

Canada,

Argentina,

Russia,

ASEAN Countries

Chapter 8 Unconventional Hydrocarbon Reservoirs

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Section 3 Development of Unconventional Hydrocarbon Reservoirs

Tight Sand Reservoir Characterization

History of Tight Sand Reservoir

Began in the 1970s, including fields in East Texas (Dew-Mimms Creek), the Piceance Basin, the Green River Basin of Wyoming (Jonah, Pinedale, Wamsutter), and the Denver-Julesberg Basin of Colorado (Wattenberg).

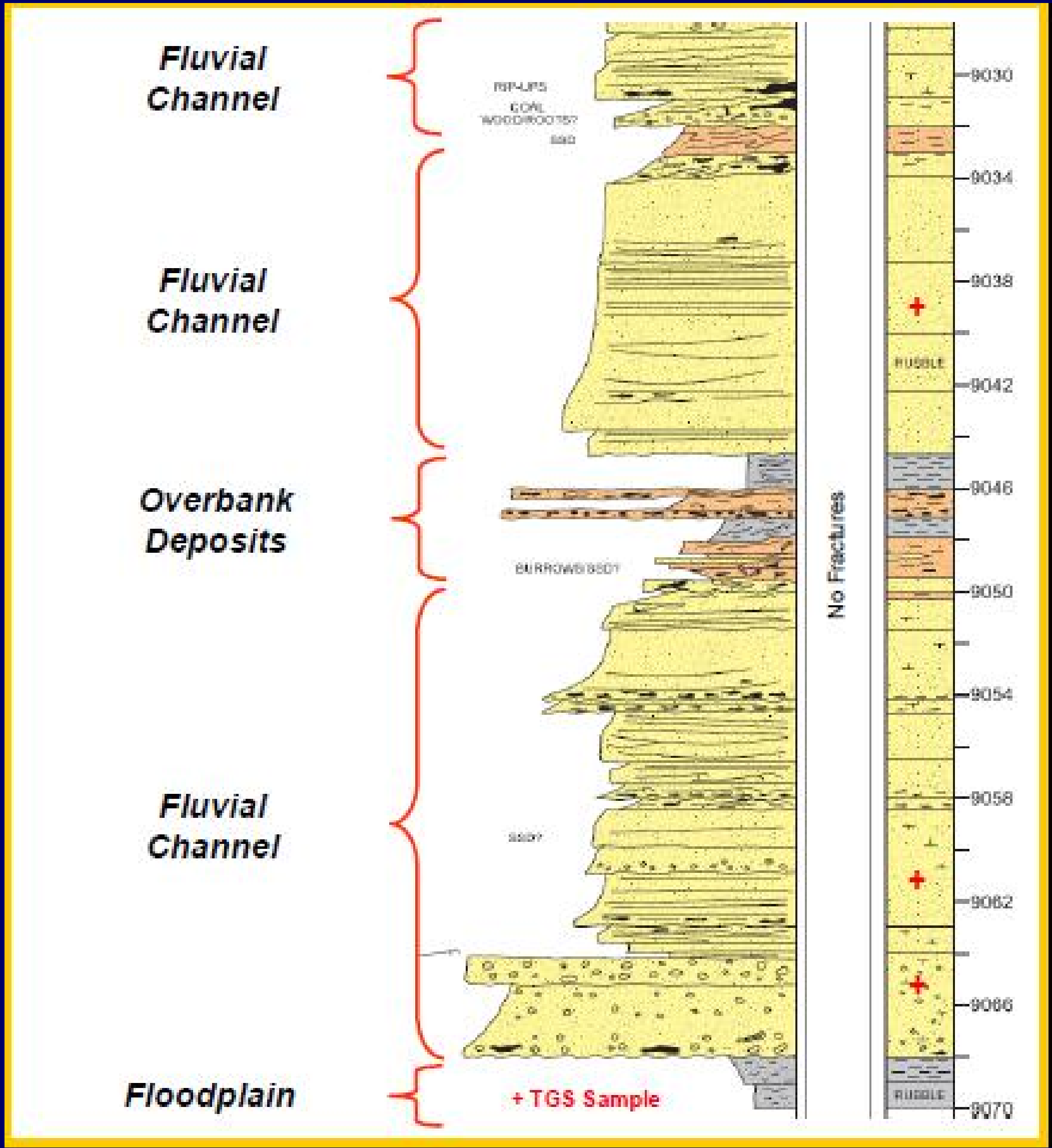
Drilling accelerated in the 1980s due, in part, to tax credits for low permeability (less than 0.1 millidarcy) reservoirs.

By the 1990s, advances in 3-D seismic, horizontal drilling, and hydraulic fracture stimulation allowed wells to be placed and completed more effectively, increasing their rates and reserves.

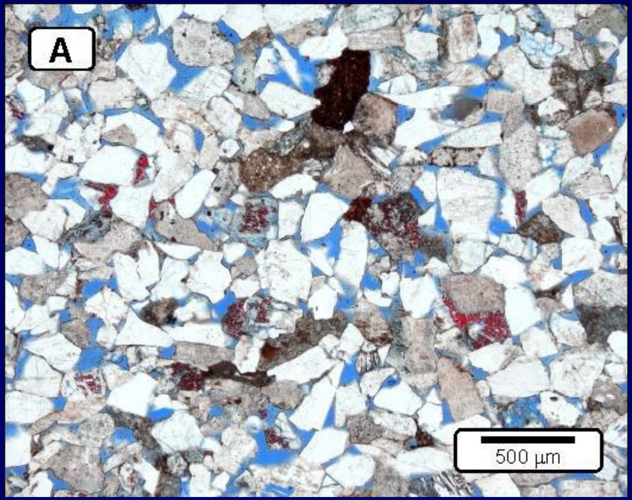
In the 2000s, rising gas prices coupled with large investments by growing companies drove-up rig counts and resulted in tens of thousands of wells being drilled.

Reservoir Example-
Mesa Verde Fluvial Channel – Point Bar

Channel Stacking Pattern

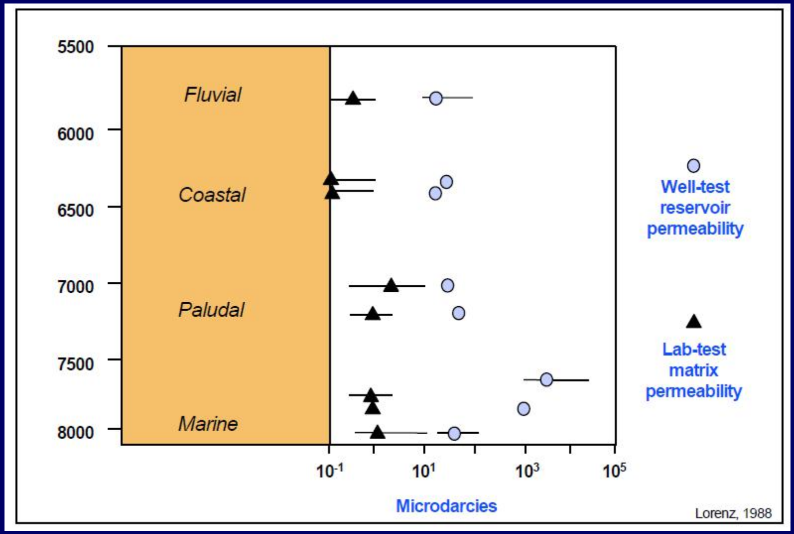


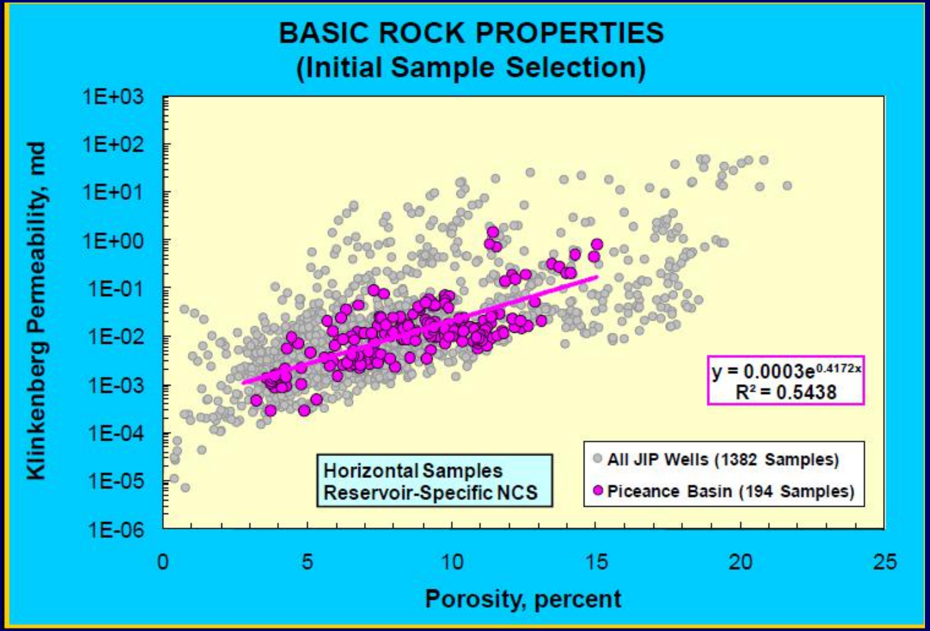
Reservoir Quality Williams Fork – Piceance Basin



Porosity= 11.9 %

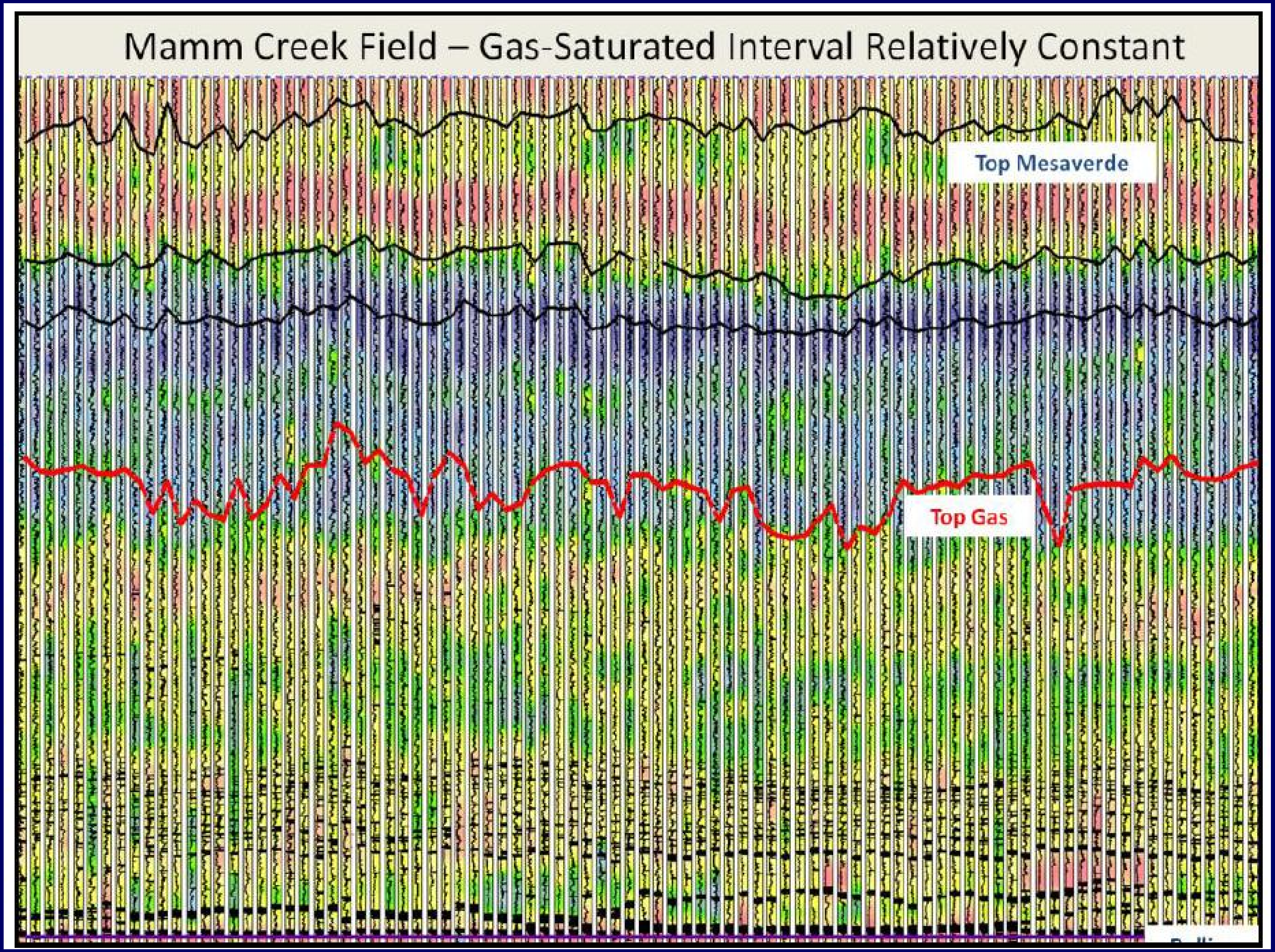
k = 0.034 md





From Corelab, 2008

Tight Gas Sand Reservoir Distribution



Perm

500uD

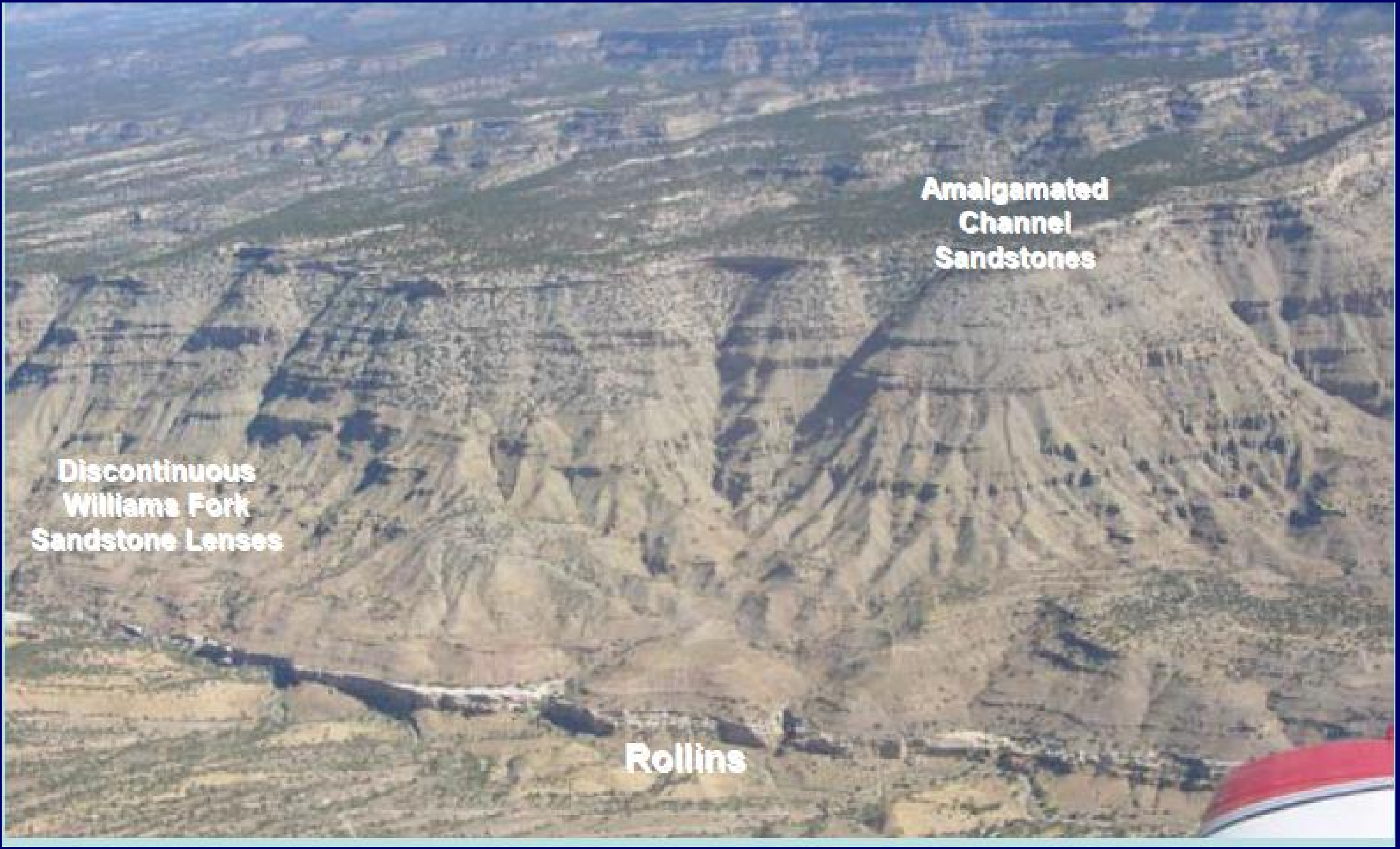
60uD

10uD

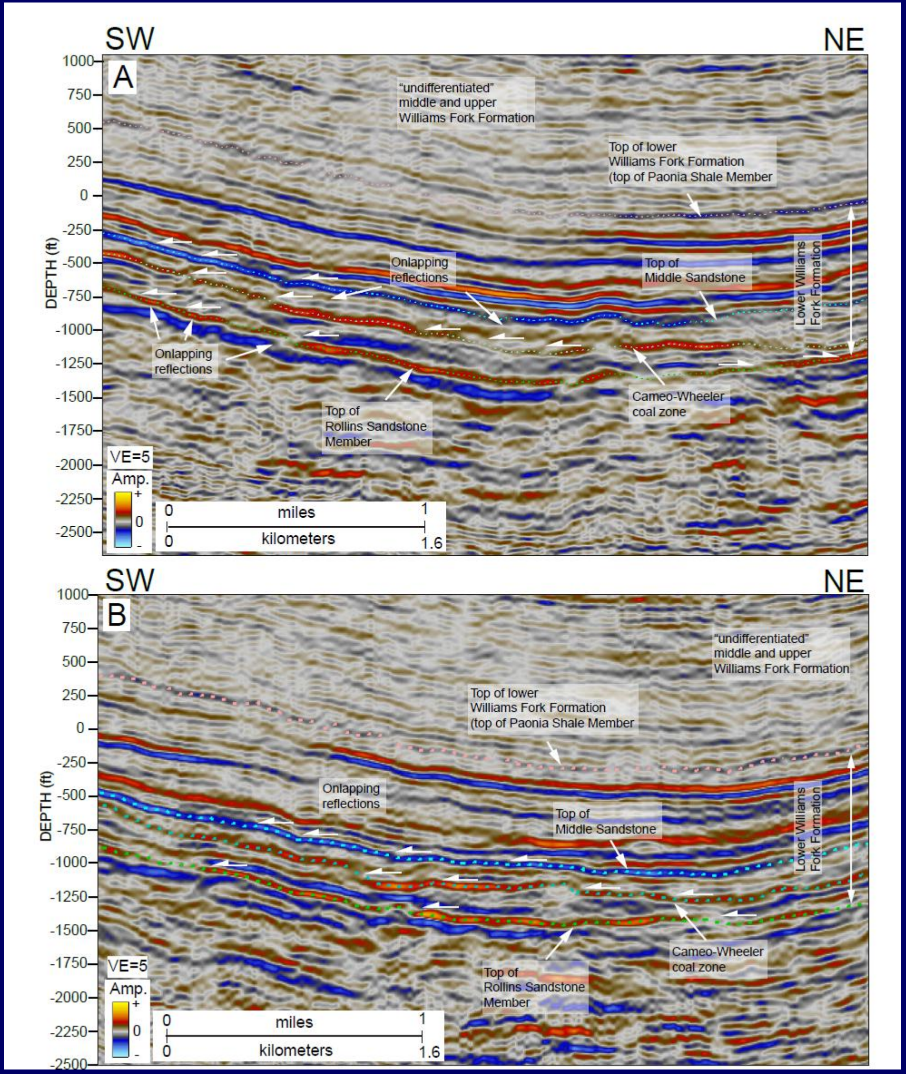
TST+HST

LST

Outcrop of Tight Sand Reservoir



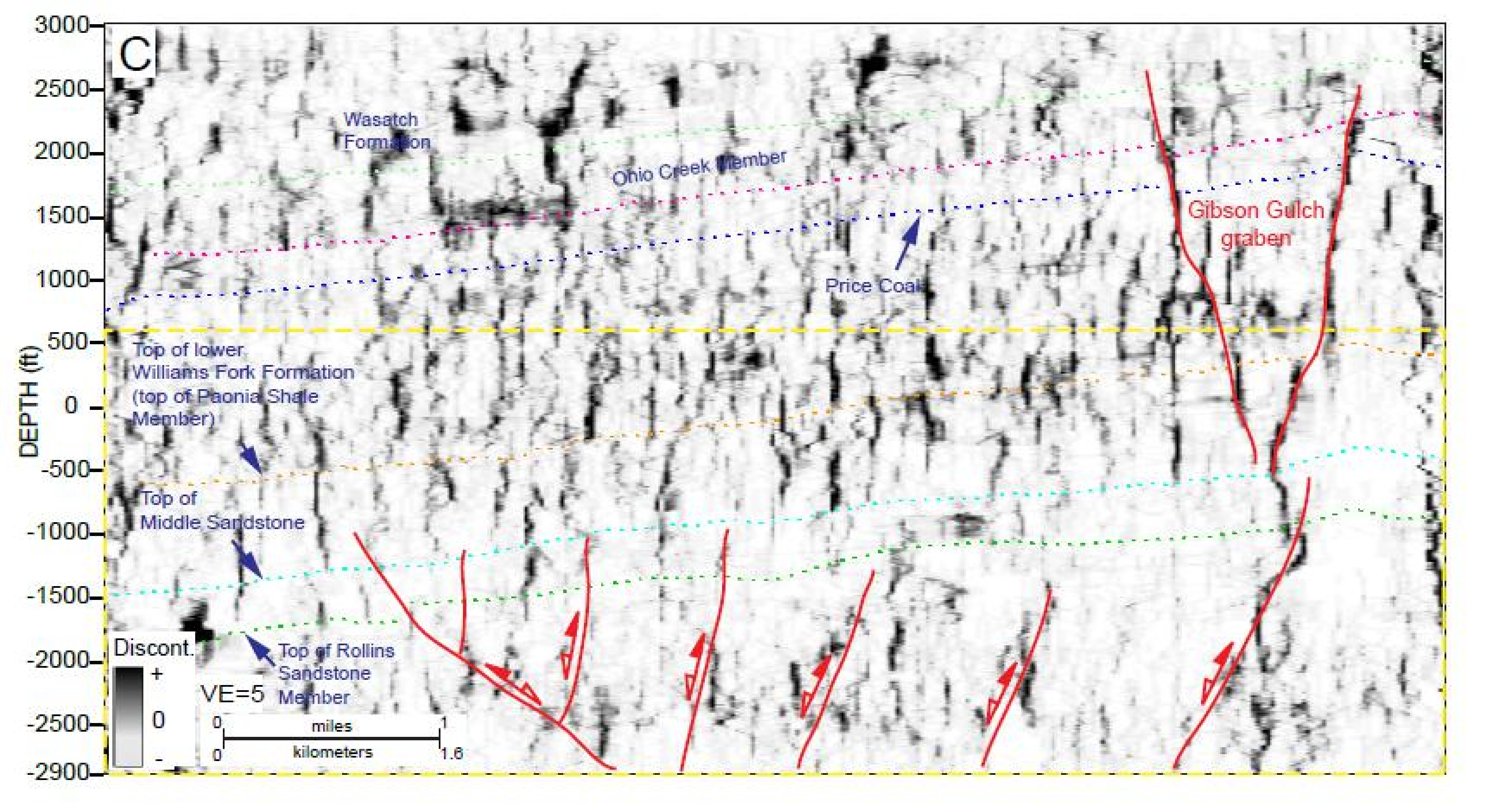
Seismic Facies in Piceance Basin



Coal: high amplitude, continuous reflection

Sandbody: high amplitude, discontinuous reflection

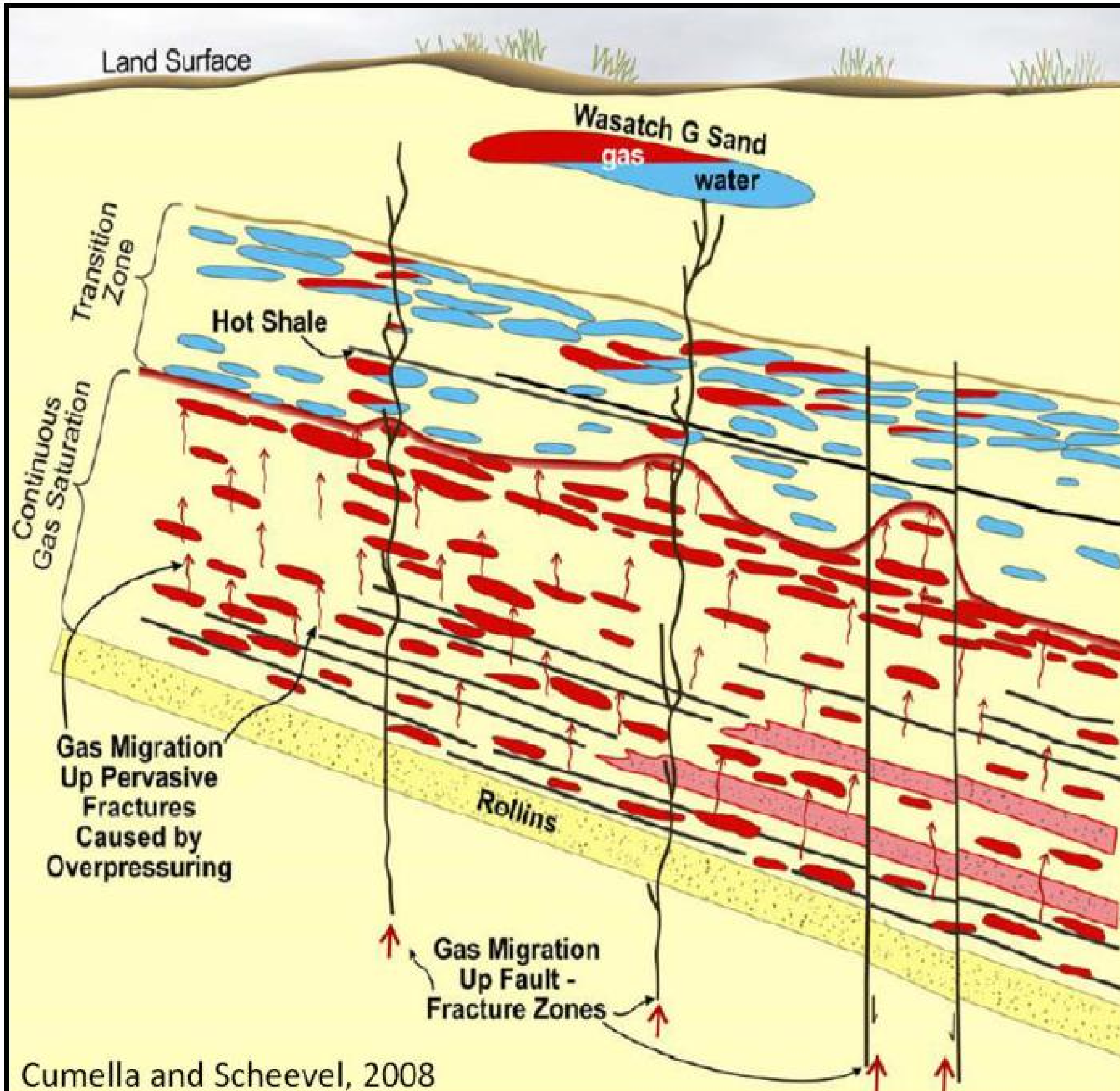
Migration Pathways



Fractrure+faults

Seismic ant-tracking result

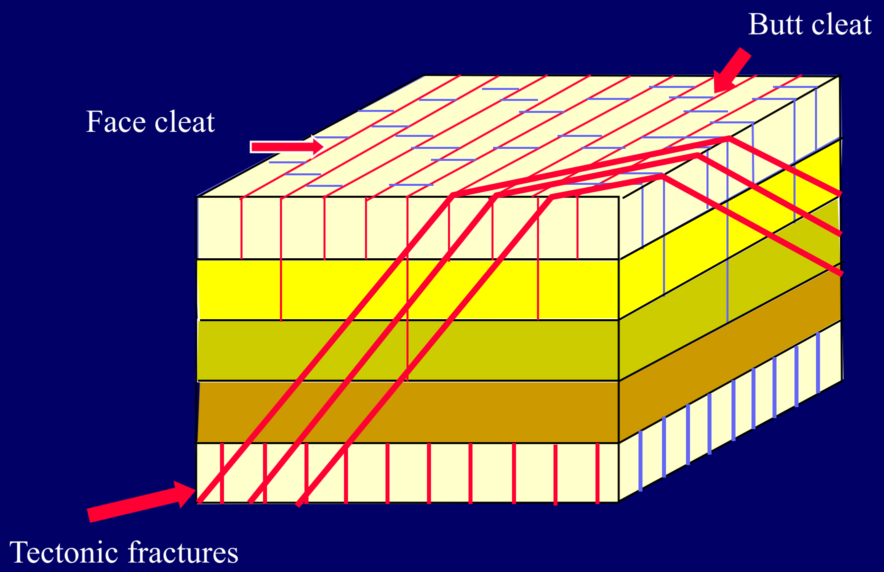
Tight Reservoir Hydrocarbons Accumulation Model



Piceance BCGA Model

- Thick, thermally mature coals generate abundant gas
- Very low perm restricts fluid flow; overpressuring results causing fracturing; gas migrates vertically
- Gas migration along major faults charges shallower transition zone pay above top continuous gas

CBM Reservoir Characterization



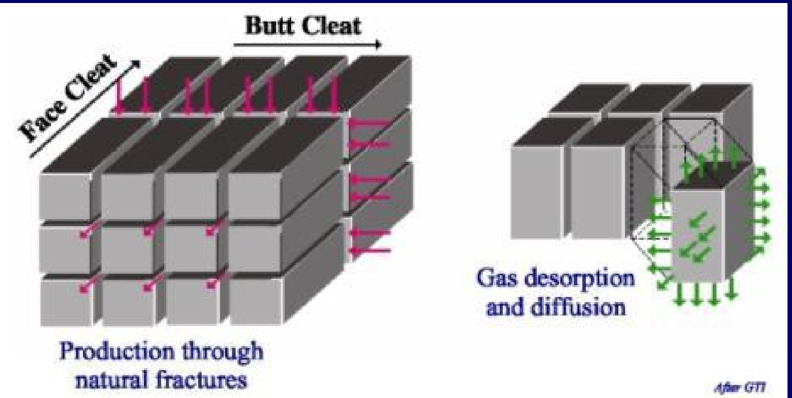
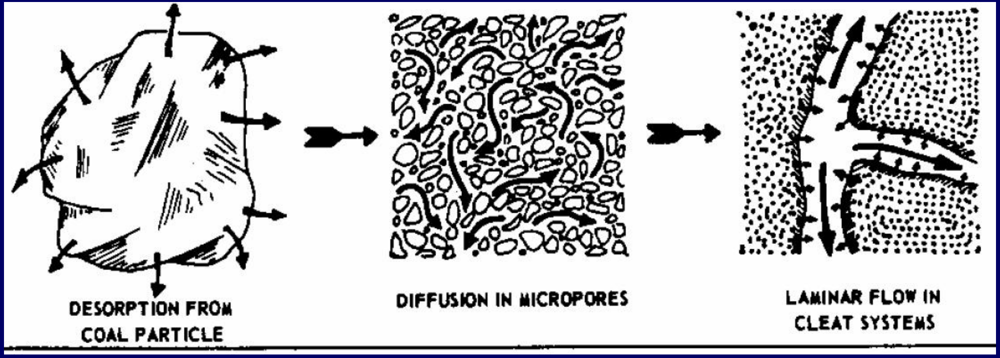


Figure 1. Coalbed Methane Development and Produced Water



CBM-Potential Coals

Age	Coal Basins	Climate / Dominant Plant Types
Carboniferous (360 – 290 my BP)	Kuzbass (Russia) Donets (Ukraine), Kazakhstan coalfields, Saar-Lorraine coalfields, UK/French coalfields, Appalachain coalfields, Cape Bretton/Newfoundland coalfields	Warm climate, moist,tropical/sub-tropical. Coal made from Lycopods (Lepidodendron and sigolaria), Gymnosperms (Cordaites) and Cycadophytes.
Permian (290 – 251 MY BP)	East Coast Australia, South Africa, India, Madagascar, South America, Antarctica. Zimbabwe, China	Climate considered to be cold with warm wet summers and freezing winters. Main plants Gymnosperms (Glossopteris and Gangangopteris)
Triassic (251 – 205 MY BP)	Callide and Tarong Australia	Cool climate warmer than Permian with similar plants
Jurassic (205 - 141 My BP)	Gunnedah, Walloon, Milmerran basins Australia, Yakutia and Pechora Basins Russia	Appearance of flowering plants such as Angiosperms, but gyymnosperms and cycads remain the major peat forming plant
Cretaceous (141 – 65 MY BP)	Canadian, Wyoming, Colorado, Spitzbergen, New Zealand, Venezuela	Cool Climate to warm, Angiosperms predominate
Tertiary (65 – 1.78 MY BP)	Indonesia (Eocene & Miocene), New Zealand (Paleocene, Eocene, Miocene, Oligicene), Australia (Eocene, Oligocene Miocene), China, Germany, Japan, USA,	Canada Warm – Angiosperms predominate.

Global CBM Plays
– Reservoir Characteristics

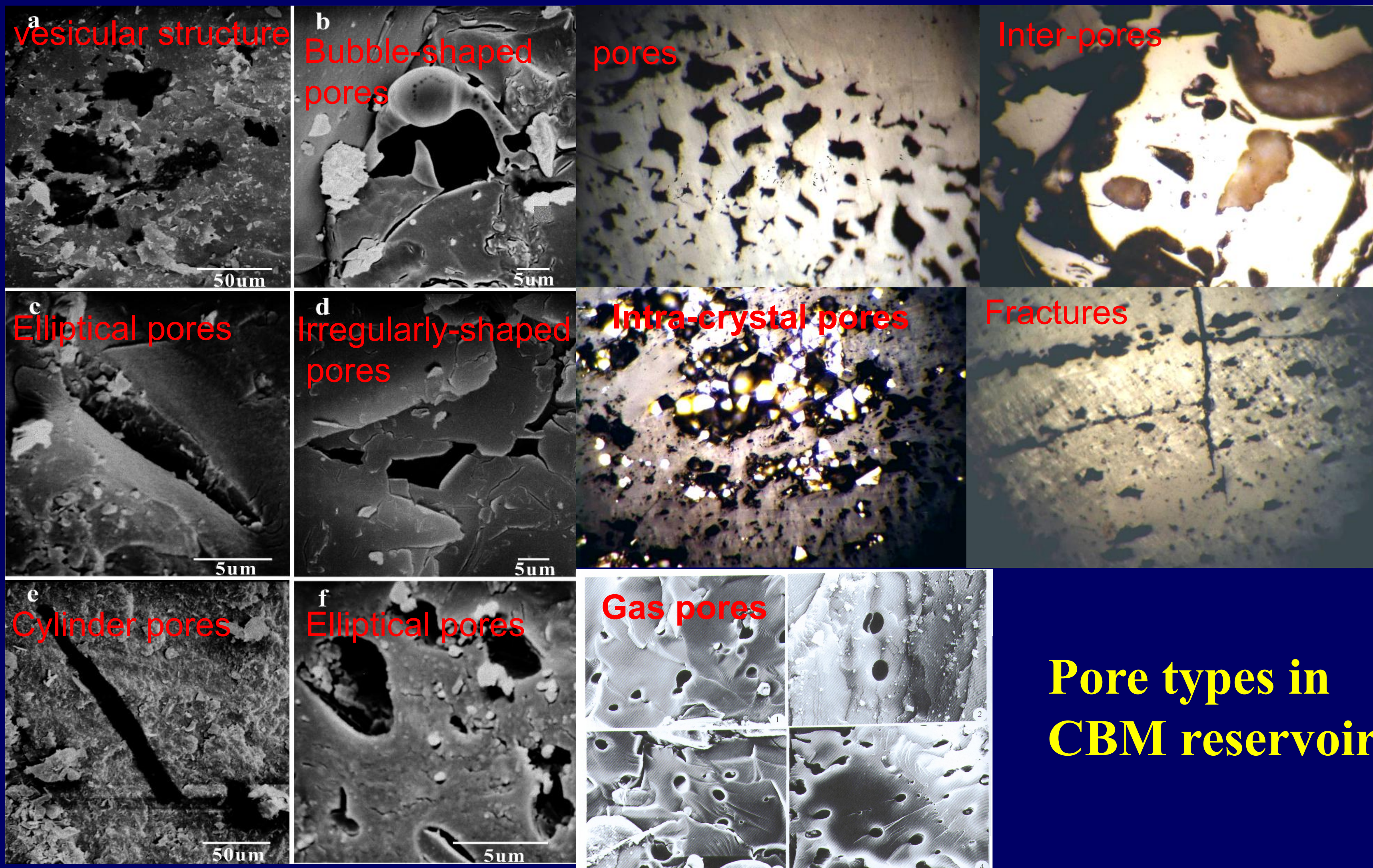
Basin	Raniganj East India	Black Warrior Basin US	North Appalachian Basin US	Powder River Basin US	San Juan Basin US	Quinshui Basin China	Bowen Basin Australia
Depth (ft)	1300 - 4500	800 - 3500	1030 - 6570	400 - 1800	500 - 5000		
Thickness of coal formation (ft)	20 - 160	1 - 10	2 - 20	70 - 150		20 - 40	50 - 100
Coal Rank	HV Bit	HV – LV Bit	HV – LV Bit	Lignite - Sub Bit	Sub Bit - LV	Anthracite	Bit
Gas Content (scf/tn)	88 - 353	125 - 680	26 - 445	25 - 75	100 - 600	300 - 900	200 - 400
Permeability (md)	0.5 - 40	0.01 - 40	0.01 - 40	1 - 1000	1 - 60	1 - 5	100
Reservoir Fluid Saturation (%)	70 - 100	80 - 100	50 - 100	100 - 100	100 - 100	-	-
Reservoir Pressure (psi)/(psi/ft)	0.433 - 0.5	0.0875 - 0.12	0.3	-	0.4	-	-
No of coal seams	6	3	6	6	2	-	-
Reserves (Bscf/well)	1 - 2	0.5 – 1.5	-	0.2 – 0.5	3 - 15	0.4 – 0.8	2.5 – 3.5

Source: SPE 103514

Working CBM System

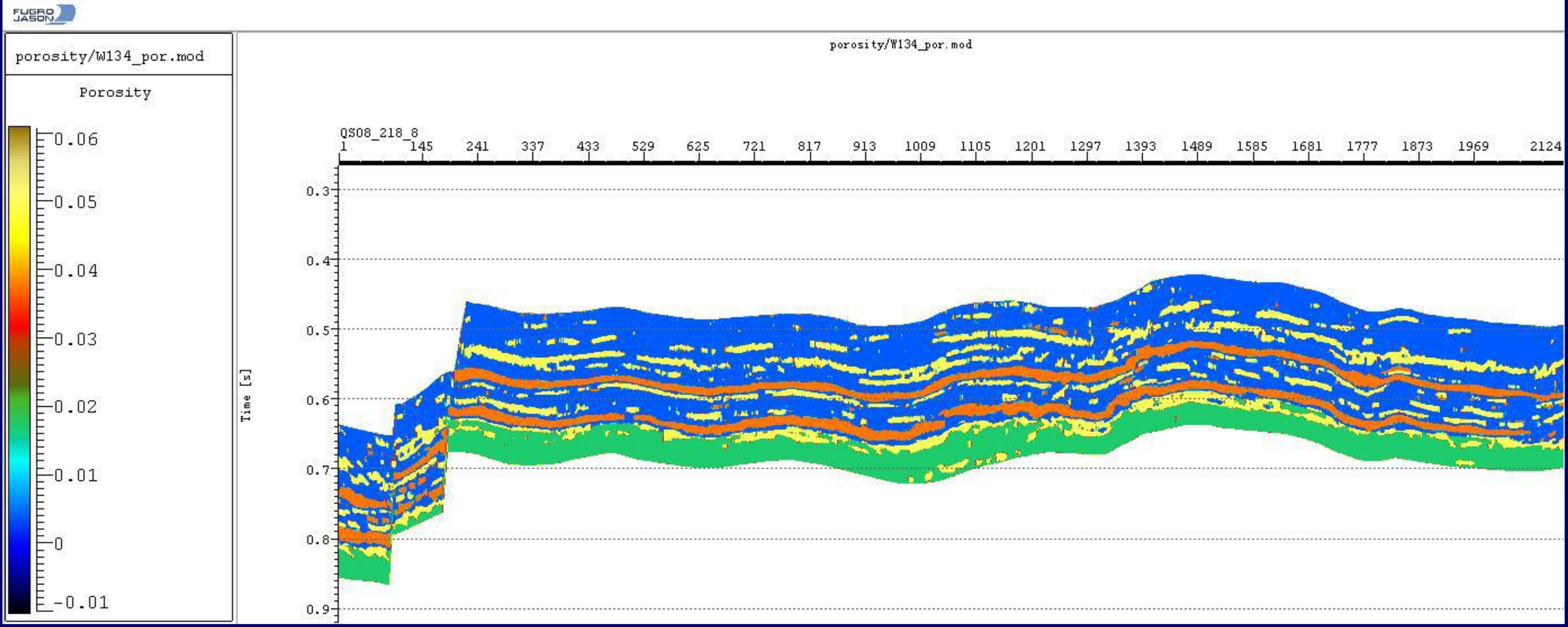
- **Good source: Coal thickness and extent of coal seams Typically > 3m in aggregate**
- **Gas Content and Gas saturation** :Biogenic and Thermogenic sourcing :2 m^3/t, 92+% CH_4 • Sorption properties of coal: >60% saturation
- Methane occurs as gas absorbed onto coal surfaces, as free gas in fractures, cleats or other porosity, and as gas dissolved in ground water within coalbeds.
- **Permeability**:Governed by presence of cleats and natural fractures • Coal Rank: 0.4 < Rvmax > 1.6 to promote cleating • Stress Setting: to promote cleat/fracture opening
- **Dewatering capability** • Isolation from pervasive aquifers

Reservoir

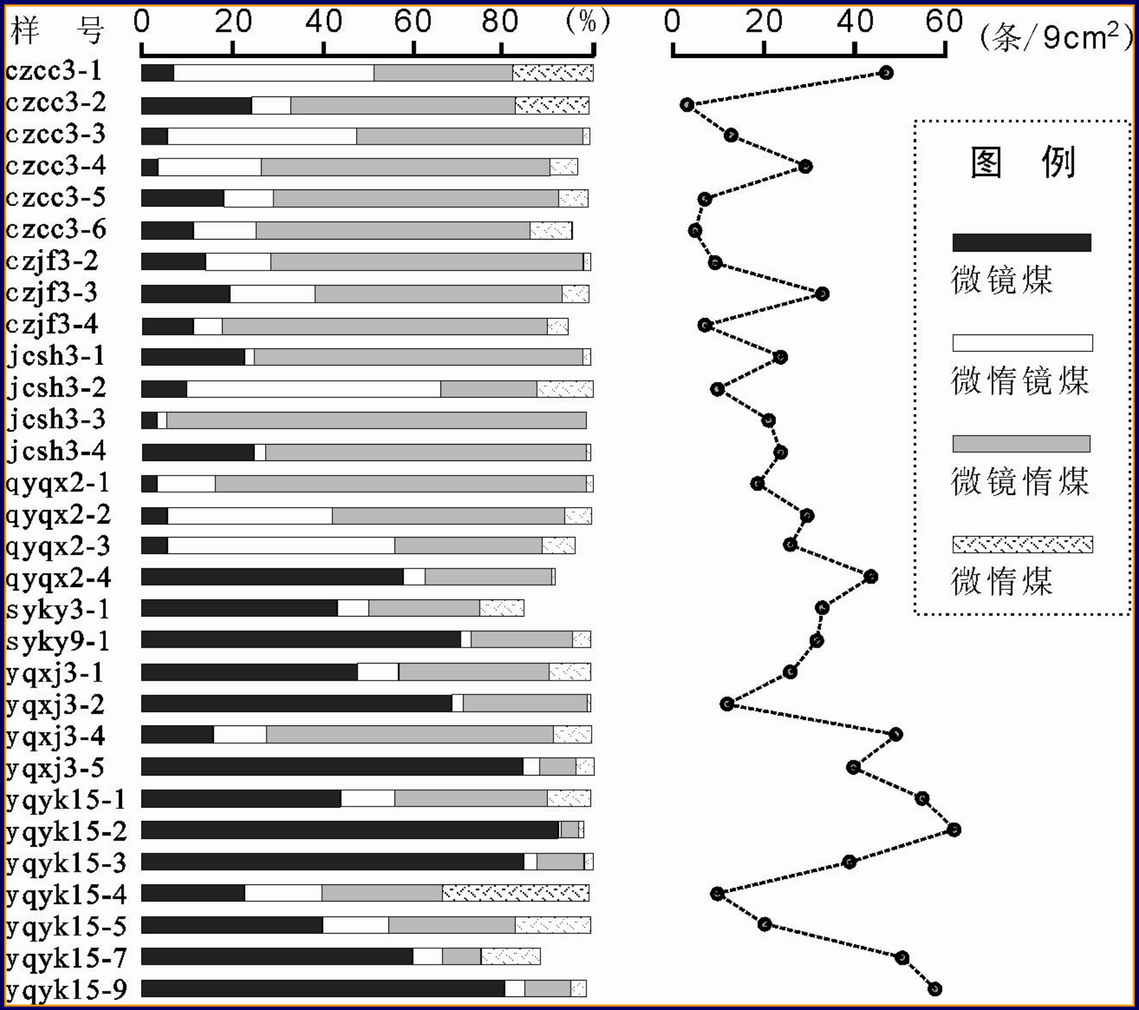


Pore types in CBM reservoir

Heterogeneity of Shale Reservoir



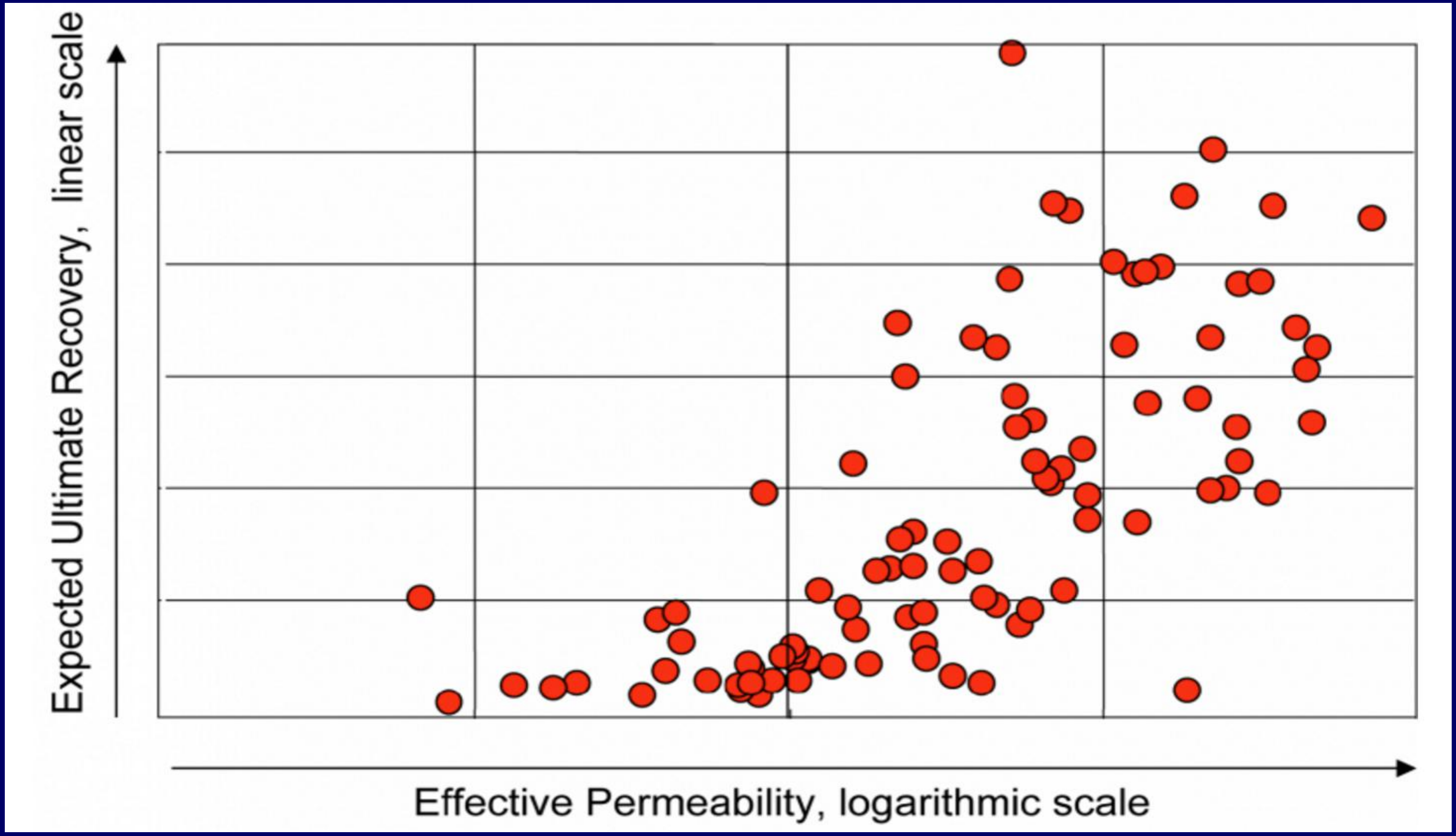
Fractures vs Coal Facies



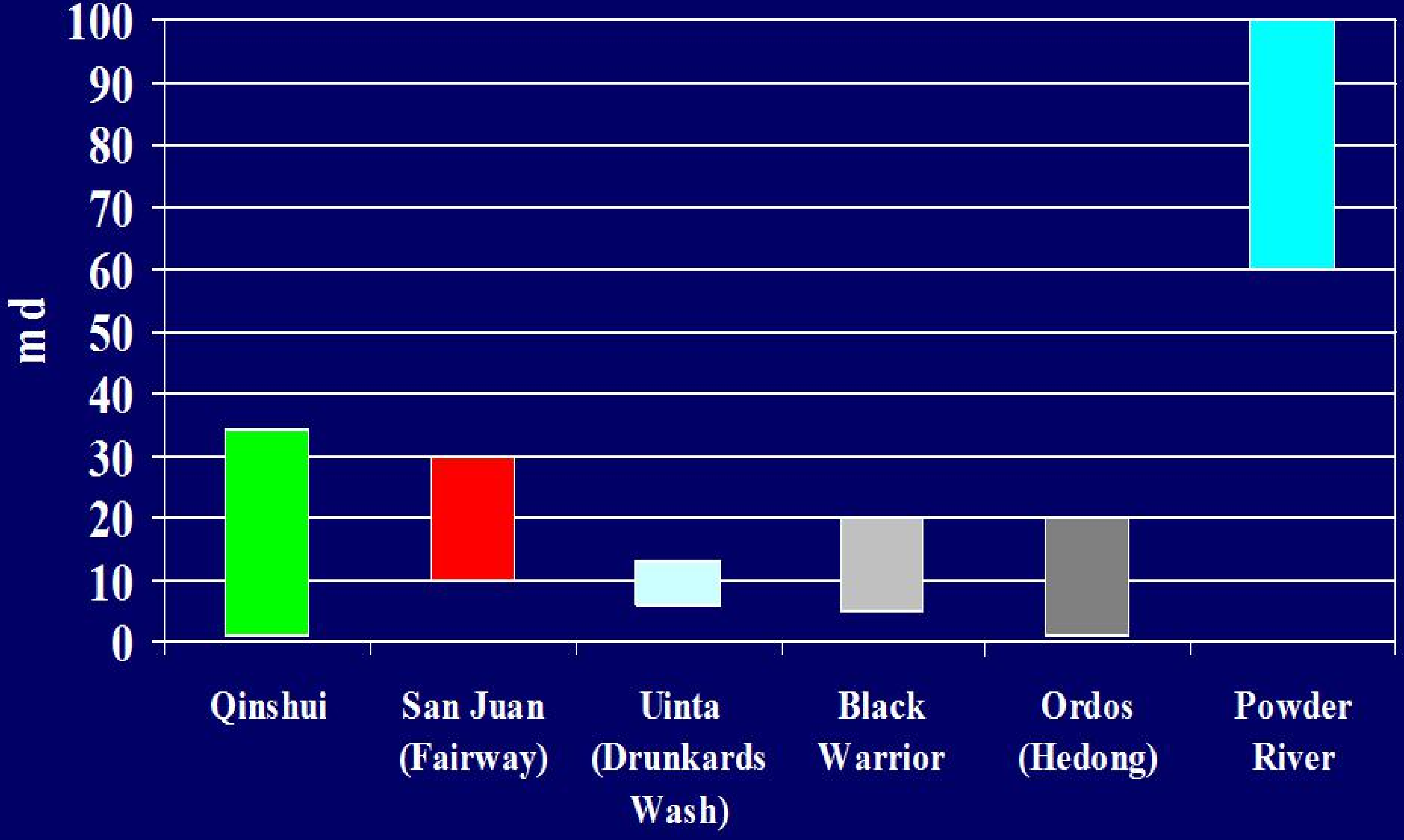
Abundant fractures in the vitrite

Less fractures in the vitrinertite

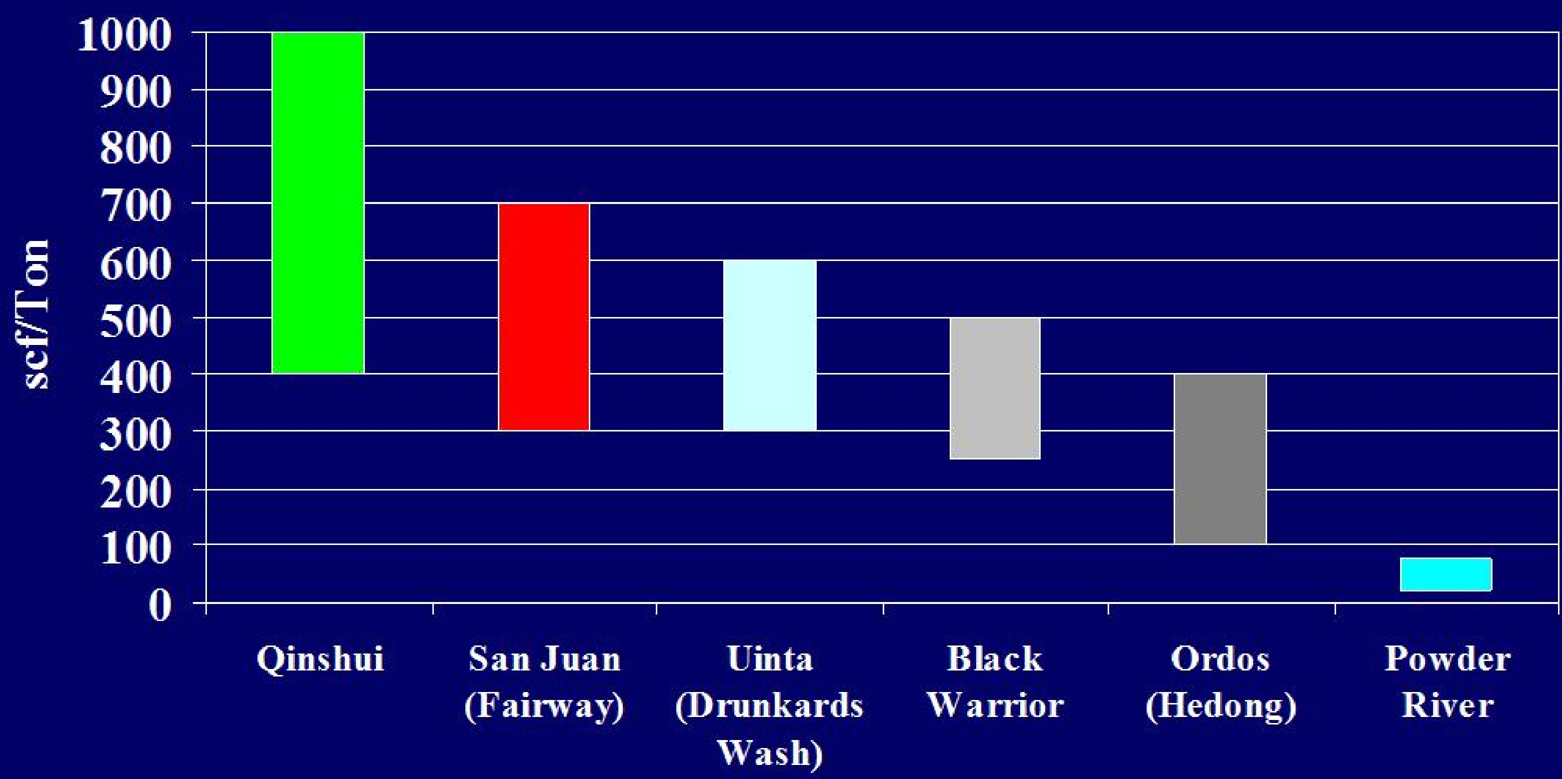
Permeability-Key for CBM Production



Permeability

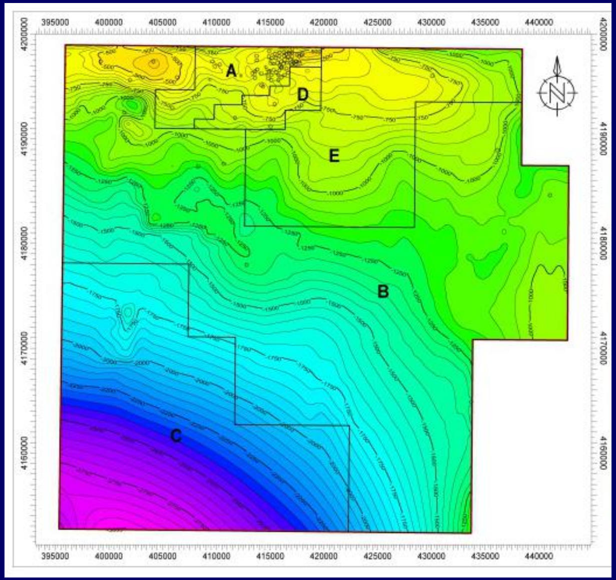


Gas Content

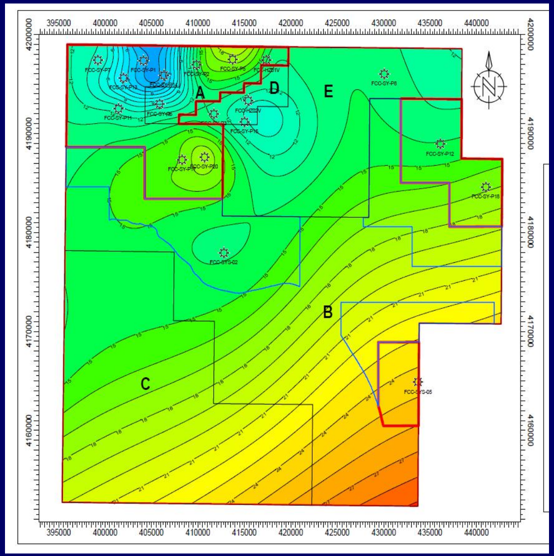


1000
900
800
700
600
500
400
300
200
100
0
scf/Ton
Qinshui
San Juan (Fairway)
Uinta (Drunkards Wash)
Black Warrior
Ordos (Hedong)
Powder River

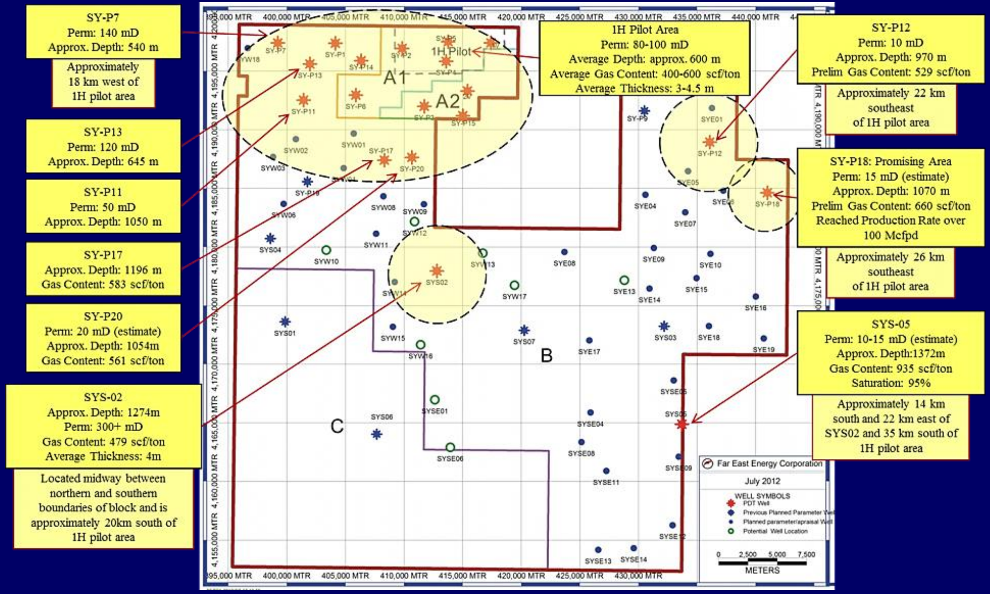
Structure vs Gas Content vs K



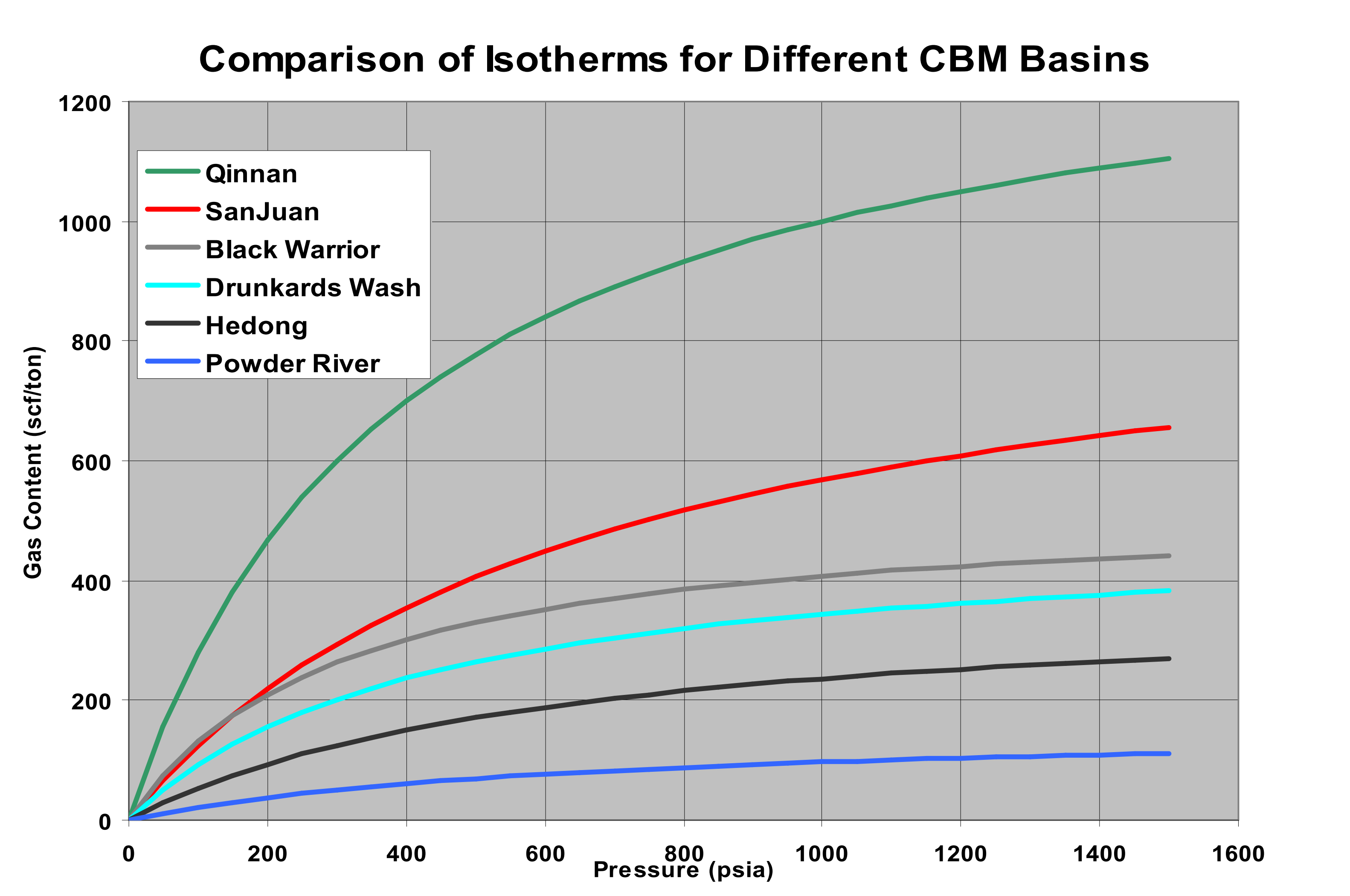
Structure



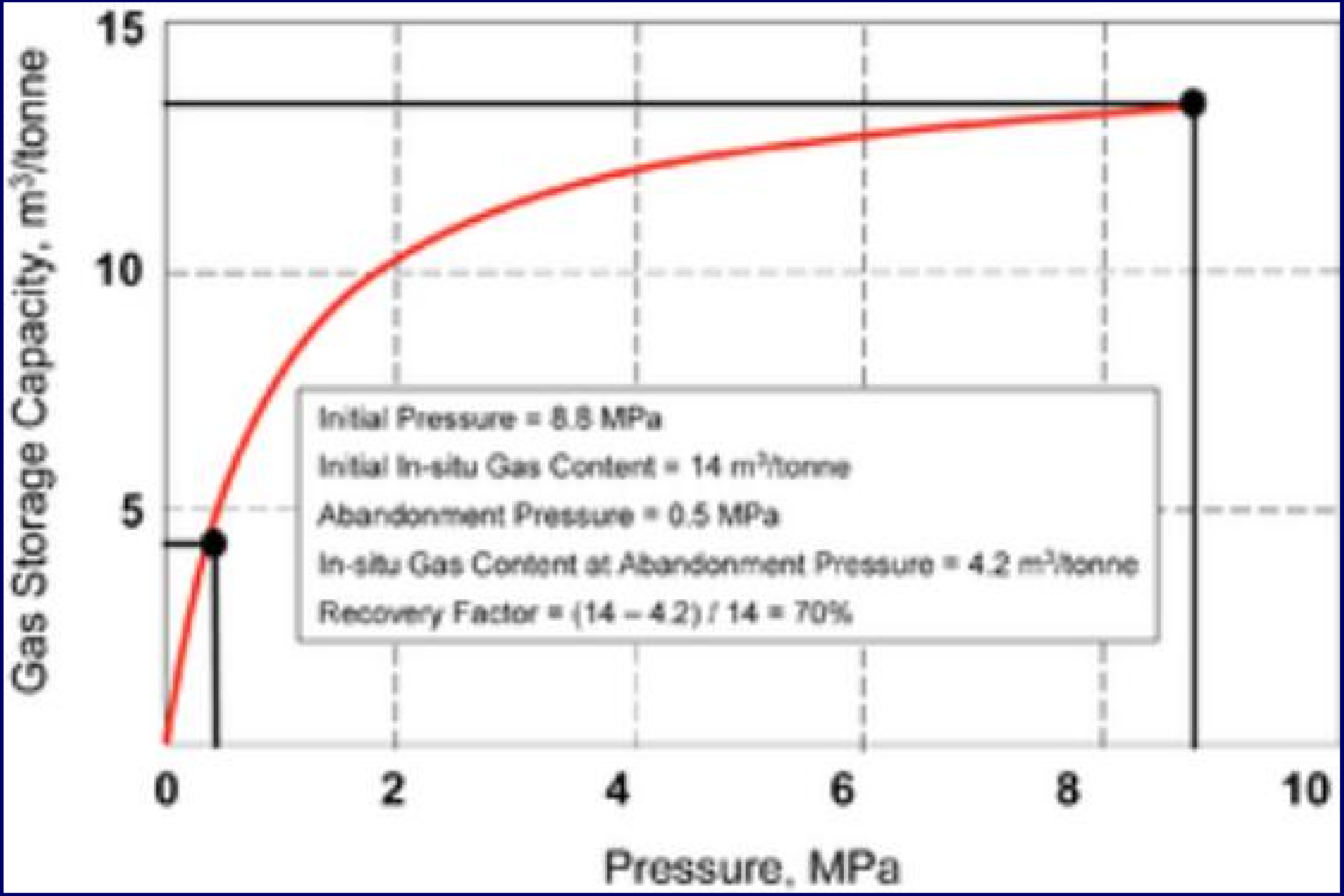
Gas content



Isotherm


Comparison of Isotherms for Different CBM Basins
1200
1000
800
600
400
200
0
Gas Content (scf/ton)
0
200
400
600
800
1000
1200
1400
1600
Pressure (psia)
Qinnan
SanJuan
Black Warrior
Drunkards Wash
Hedong
Powder River

Sorption isotherm vs recovery factor



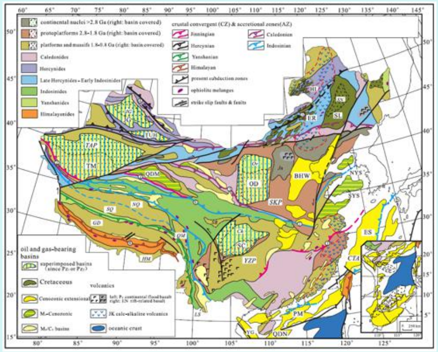
Shale Reservoir Characterization

- Fine-grained Organic Rich Rock, Includes Shales, Mudstones, Siltstones, and Very Fine Grained Sandstone, Both Siliceous and Carbonate-rich Composition.
- Can be ductile or brittle. Fractures may or may not open
- Vertically and laterally heterogeneous
- Nano to Pico darcy matrix permeablity
- Low Natural Production, Requires Stimulation
- Usually Self-Enclosed, Source, cap and Reservoir Same
- Gas Stored As Free, Solution, and Sorbed.


Gale, AAPG, 2008

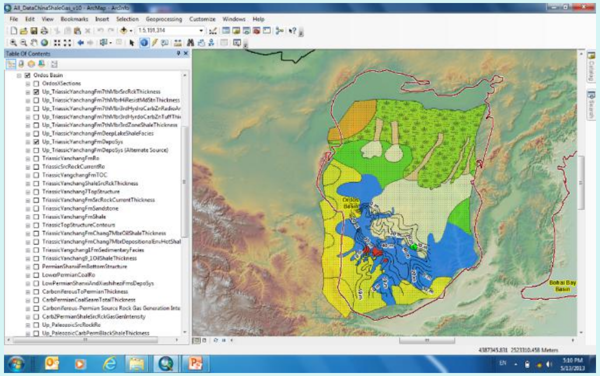
Integrated Multi-scale & Multi-discipline Reservoir Characterization

Regional tectonic framework



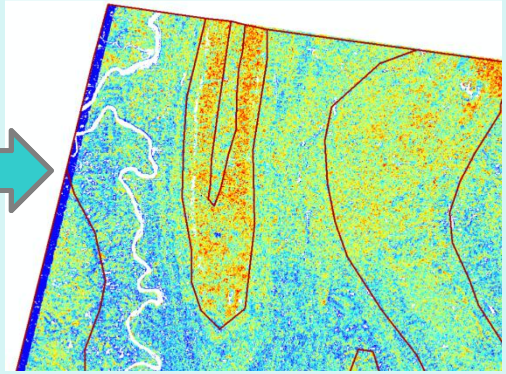
H. Wang and S. Li, 2004

Basin scale maps



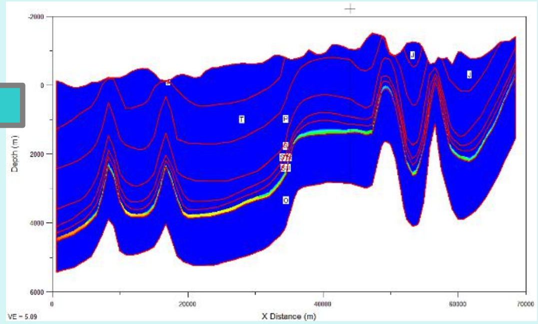
Phase 1

Satellite data analysis

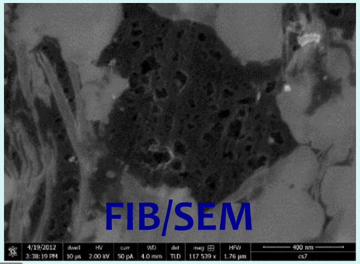


Phase 1

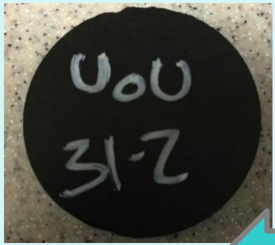
Shale system modeling

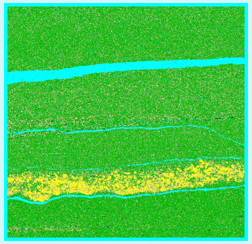


Core, well data, sample test

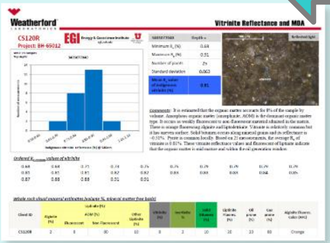


FIB/SEM



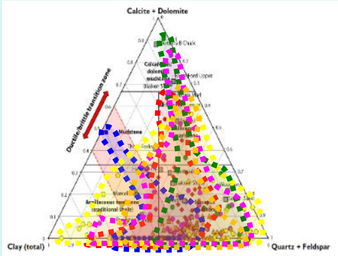


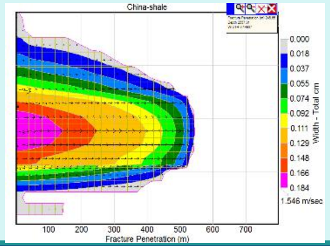
QEMSCAN®



Geochem

G&G and Engineering Data integration & analysis





Learnings of Regional Setting of US Shale Plays

Foreland tectonic and marine depositional control

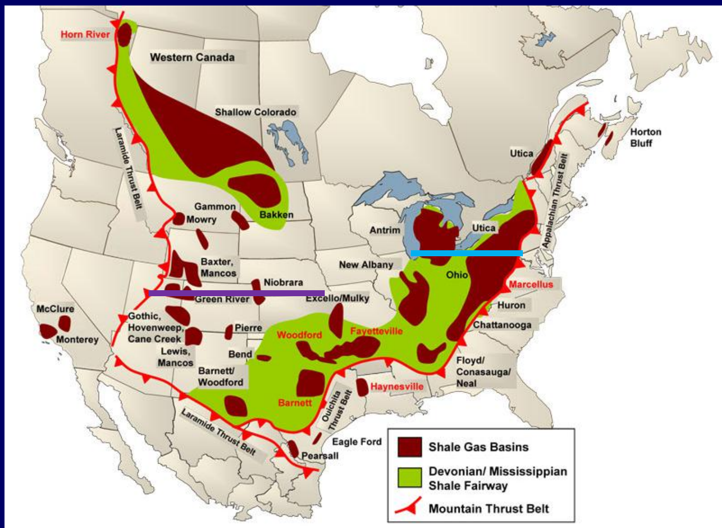
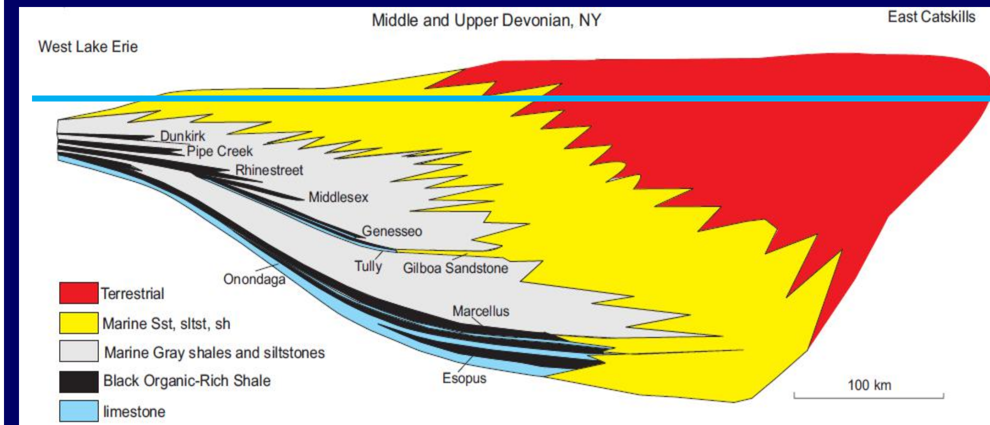
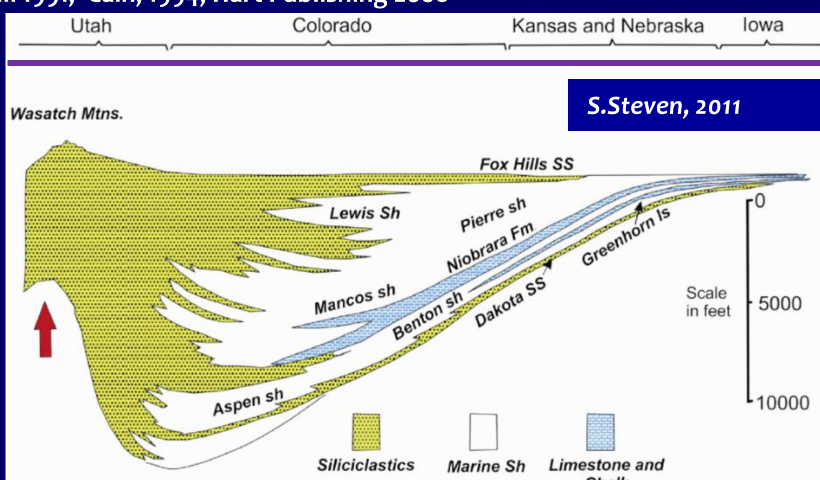


Image from Ziff Energy



Source: Advanced Resources, SPE/Holditch Nov. 2002;
Hill 1991, Cain, 1994; Hart Publishing 2008



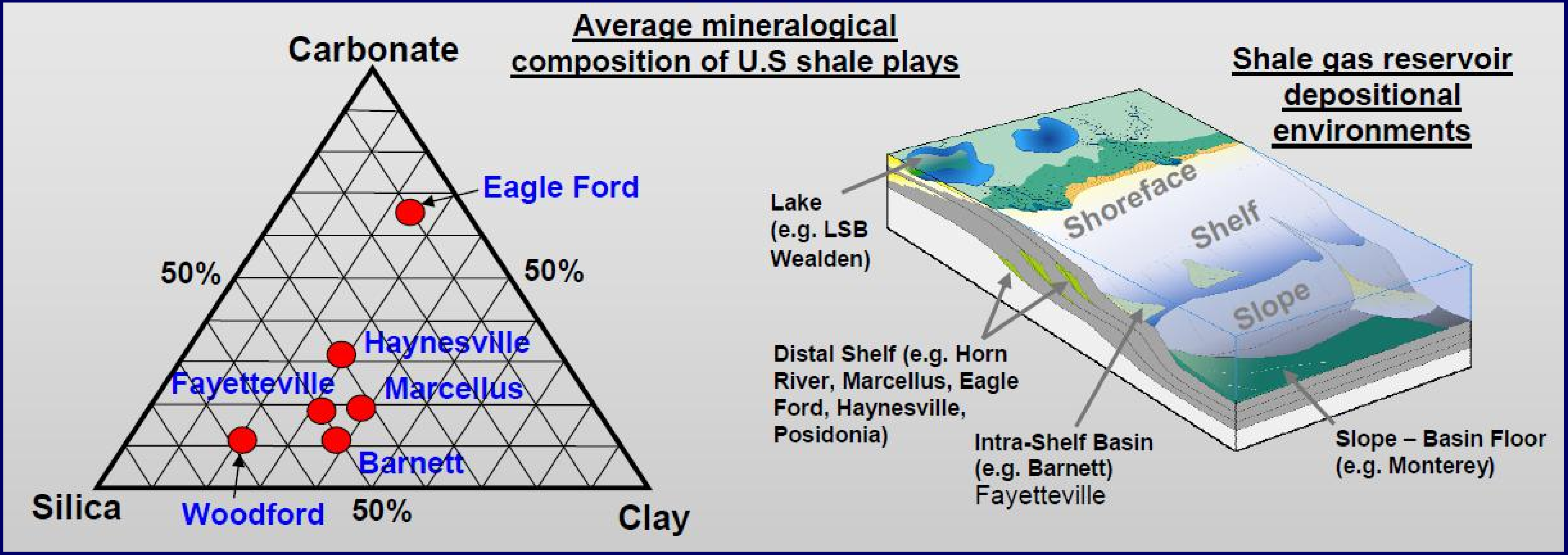
TOC, Brittleness

Increase

Mancos **Baxter** **Niobrara**

High TOC and brittle fine-grained sediments far away from clastic influx

Tectonics and Depositional Settings of US Shales



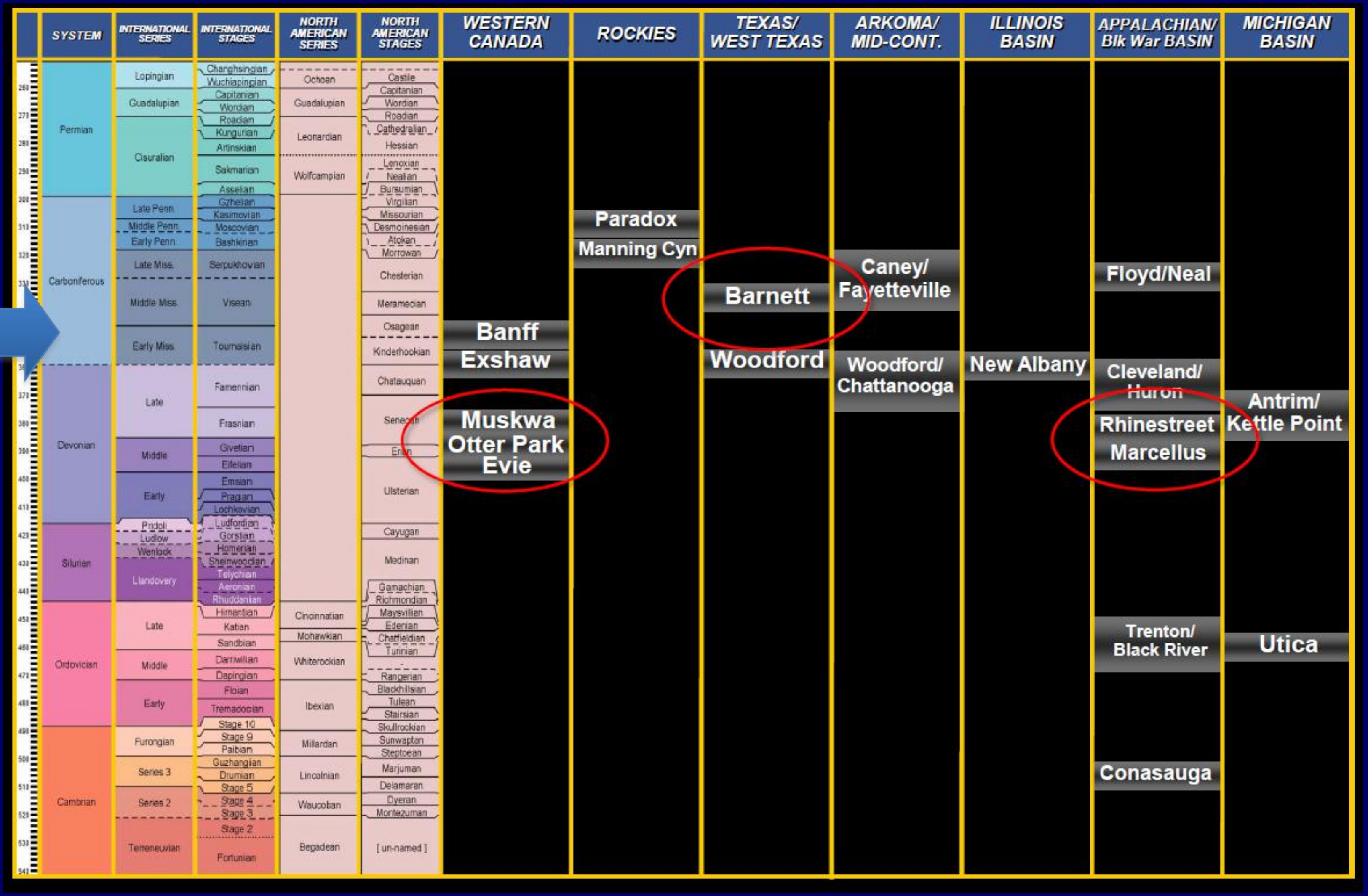
Depositional control

M. Pospisil and R.Powell, 2011

Lacustrine → Transitional → Marine

Paleozoic US shale Plays

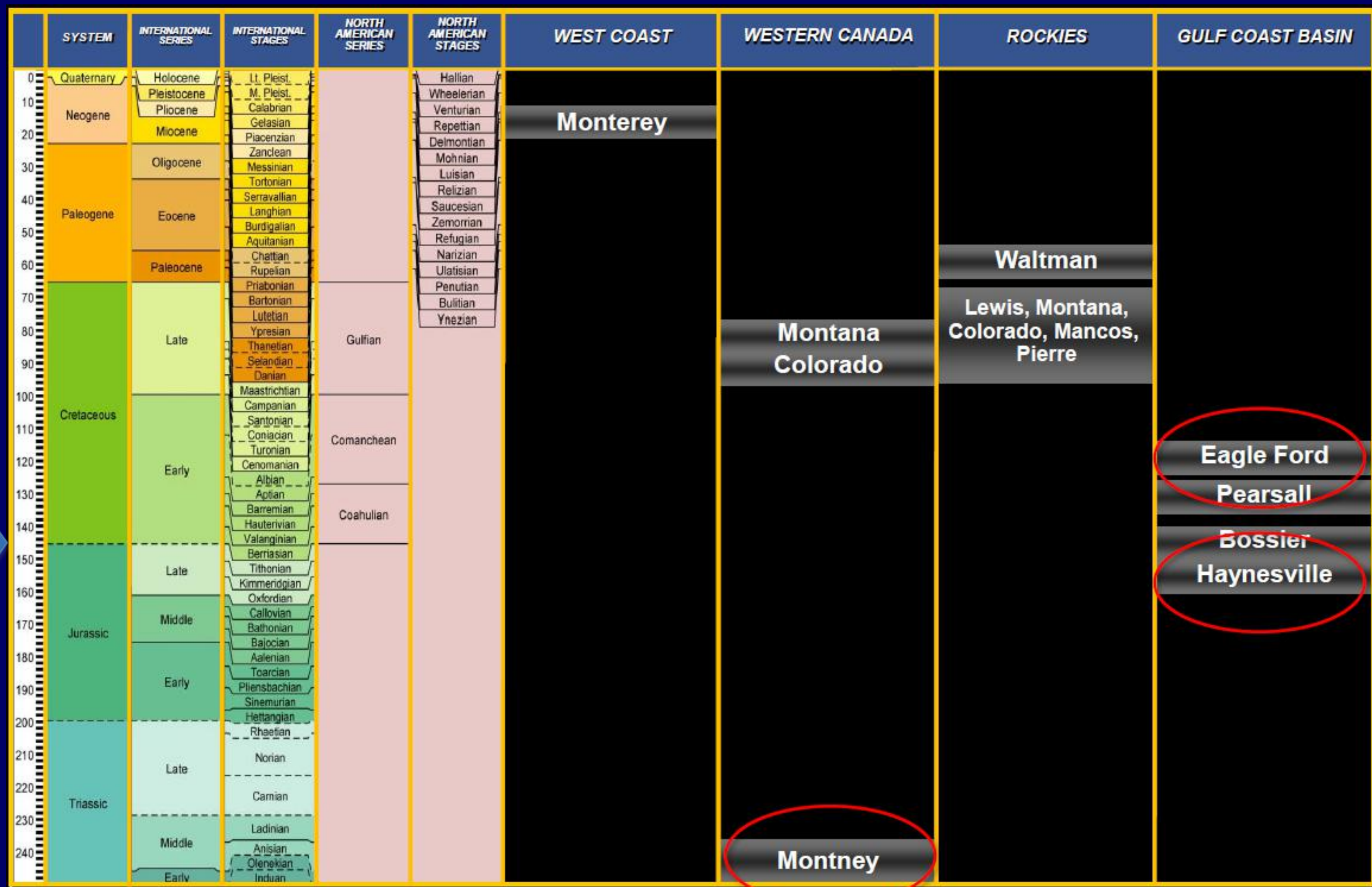
Significant in US



Corelab, C.D. Hall, 2010

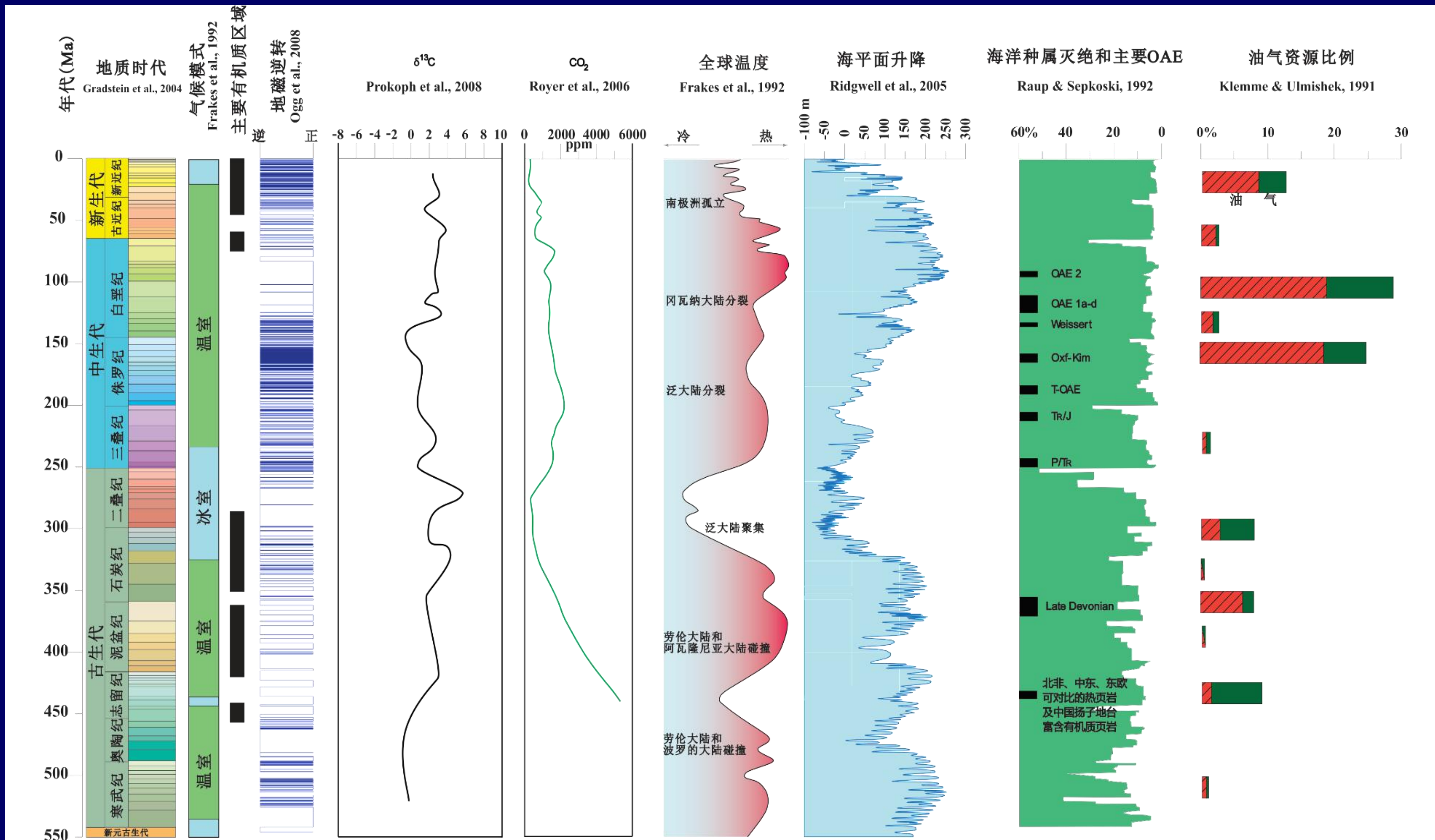
Meso-Cenozoic US shale Plays

Significant in US

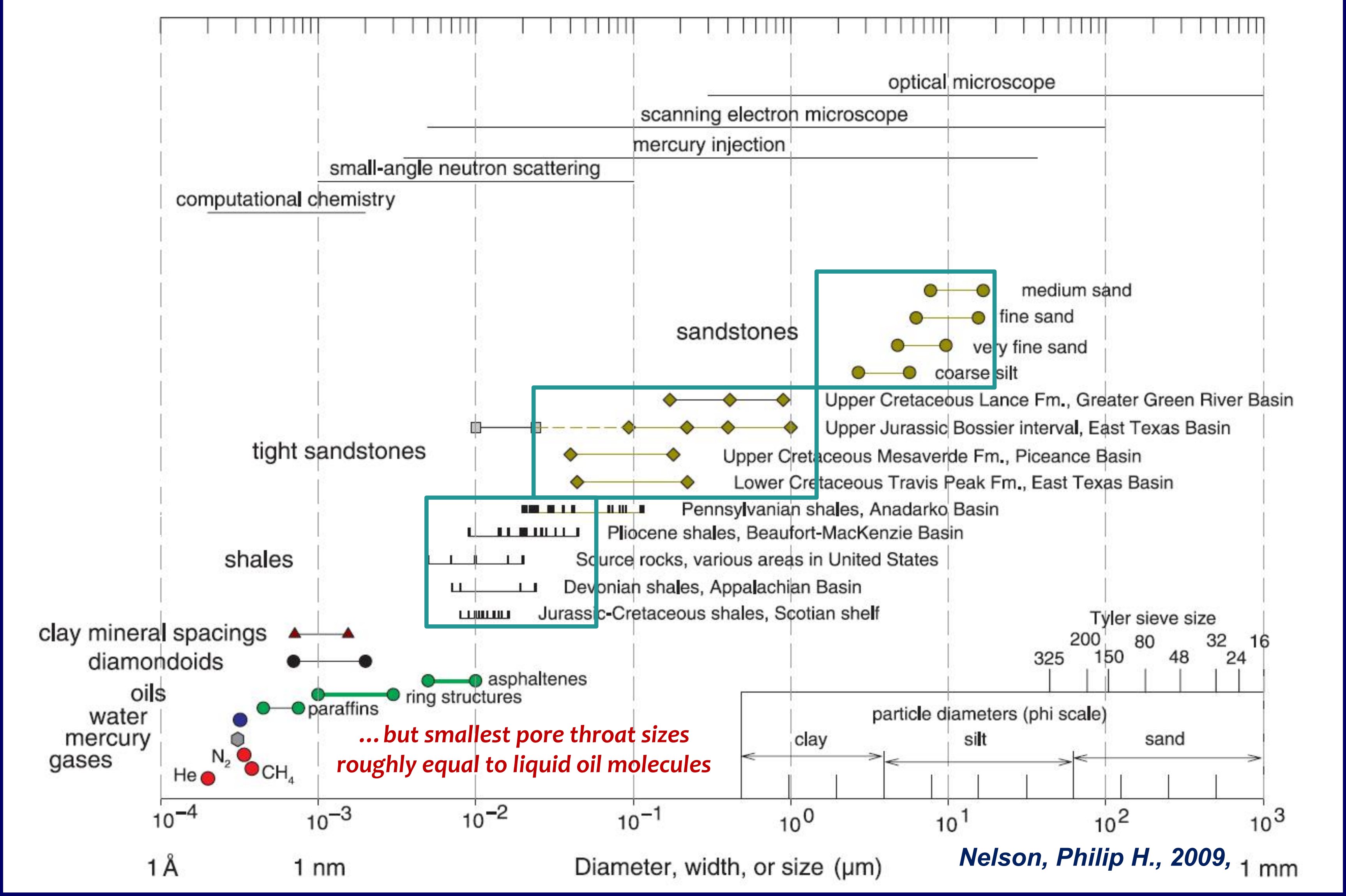


Corelab, C.D. Hall, 2010

Settings of Global Shale

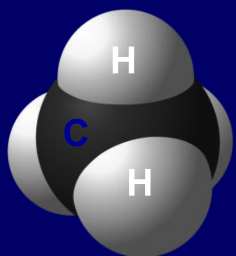


Shale Reservoir Quality

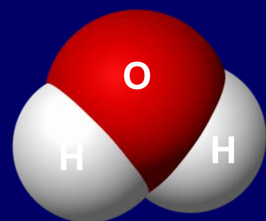


Reservoir Storage of Tight Shale

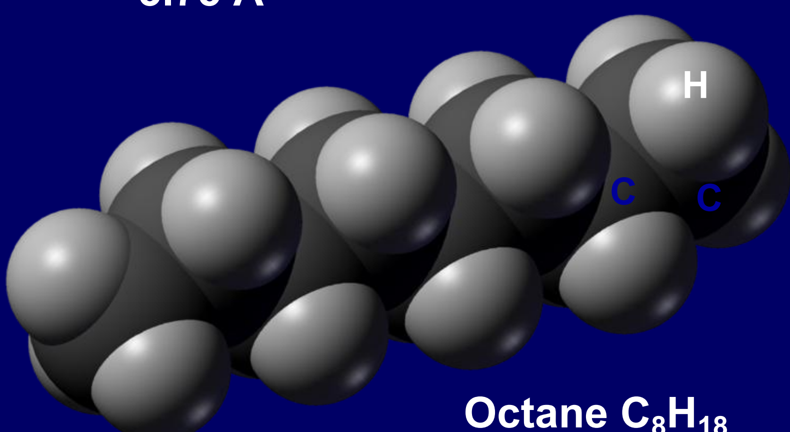
Production results indicate we are able to extract oil at flow rates previously thought impossible. We are evaluating how liquid molecules flow through nano-pore-throats.



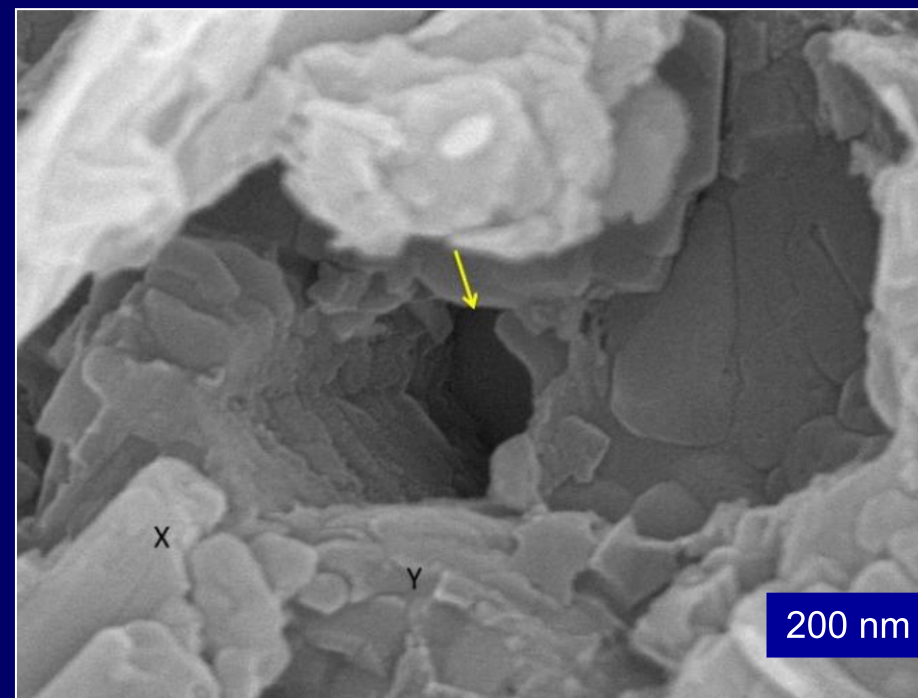
Methane CH4
3.75 Å



Water H_2O
3.0 Å



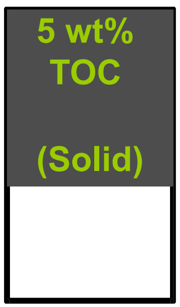
Octane C_8H_{18}
length 13.17 Å, height 4.85 Å



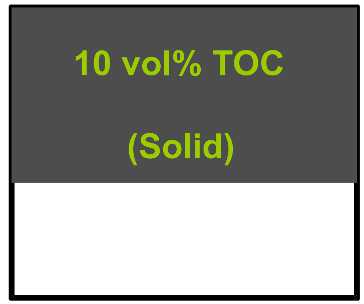
Close-up view of nano-pore (arrow) in fecal pellet in phosphatic facies of Barnett Shale. X and Y are fluorapatite crystals.
Source: Slatt and O’Brien, 2011, Pore Types in the Barnett and Woodford Gas Shales: AAPG Search & Discovery 80166

Importance of Organic Matter

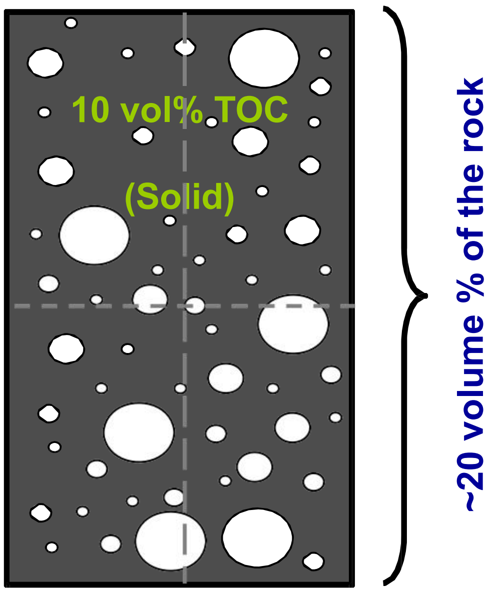
For a "Typical" Shale Gas the current TOC = 5 wt%



Because the grain density of organic matter is ~½ that of rock minerals, the vol% TOC is ~2 times the wt% TOC



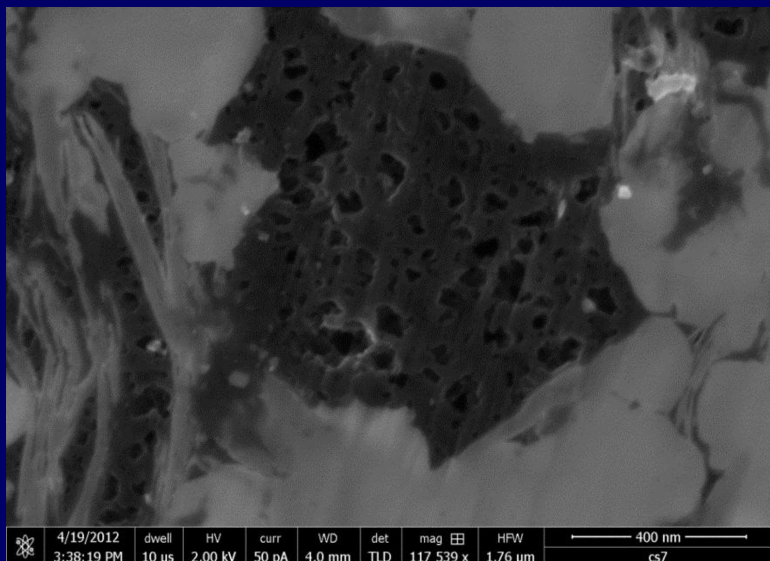
If 50 vol% of the <u>original</u> organic matter volume is now pores, the volume impacted by the current 5 wt% TOC is approximately 20 vol% of the rock.



(After Passey et al., 2010)

Storage – China Marine and Lacustrine Shales

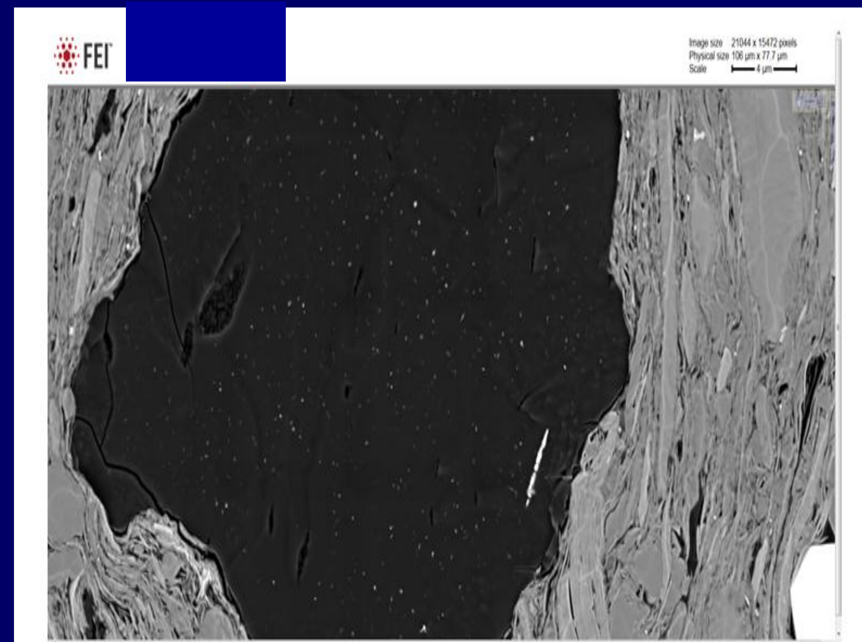
Silurian Marine



TOC = 2.5%, R_o = 1.5%,
and quartz content is 53%.

China marine shales are generally more tight (with 2-5% porosity) than US shales

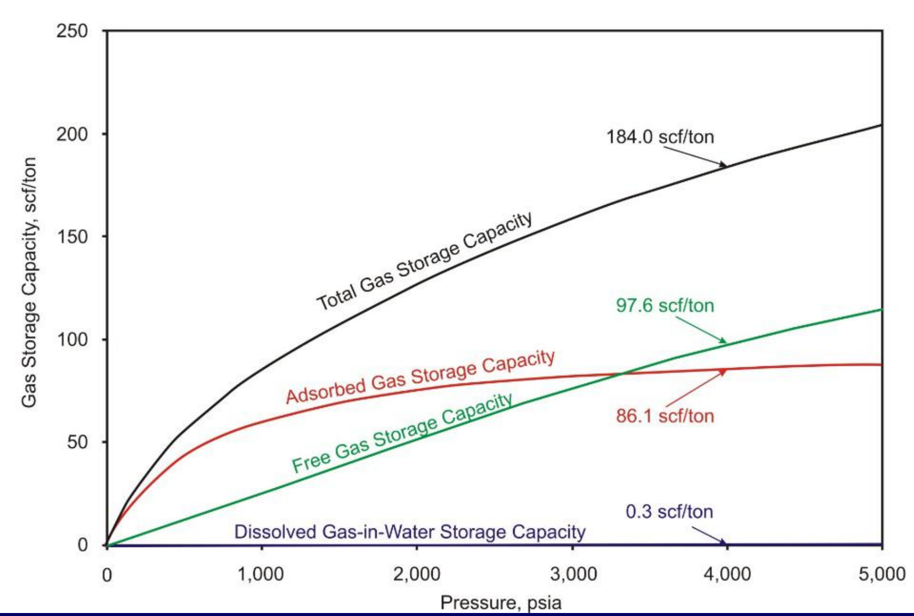
Triassic Lacustrine

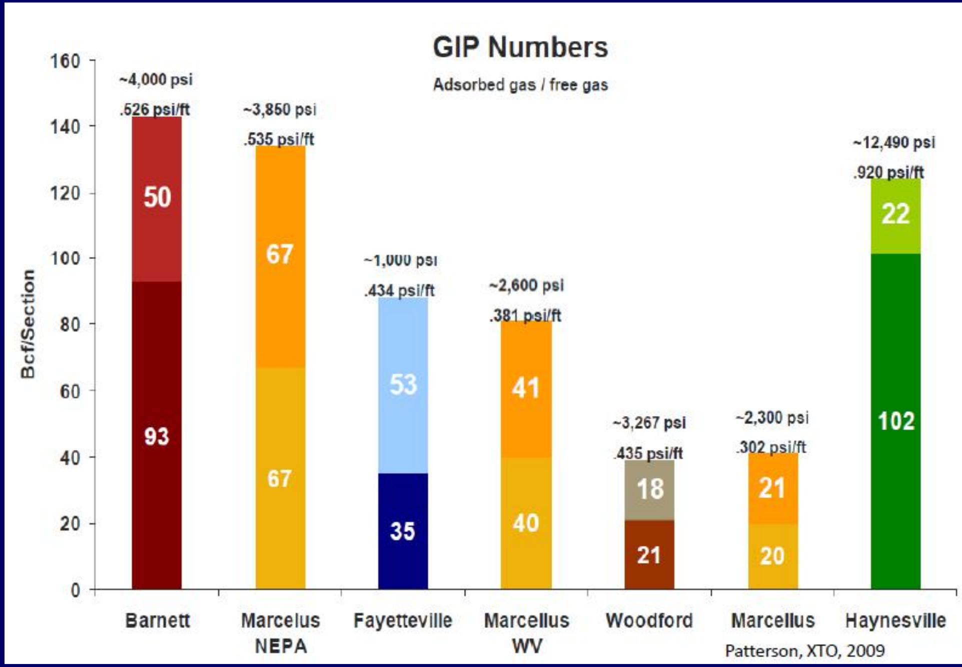


TOC = 5.24%, R_o = 0.77%,
and quartz content is 19%.

More nano-pores in high maturity marine shale than low maturity lacustrine shale

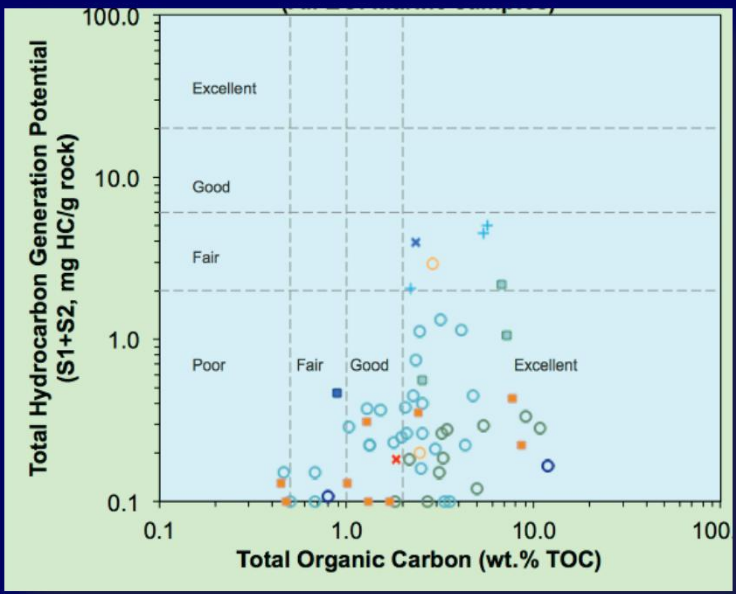
Free and Adsorbed Gas





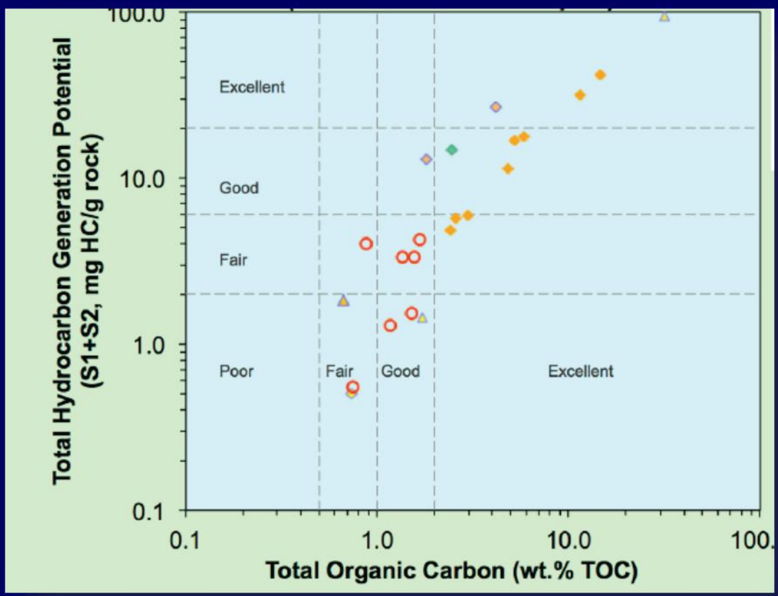
Source Rock Quality Comparison of Marine and Lacustrine Shale Samples

Marine shale



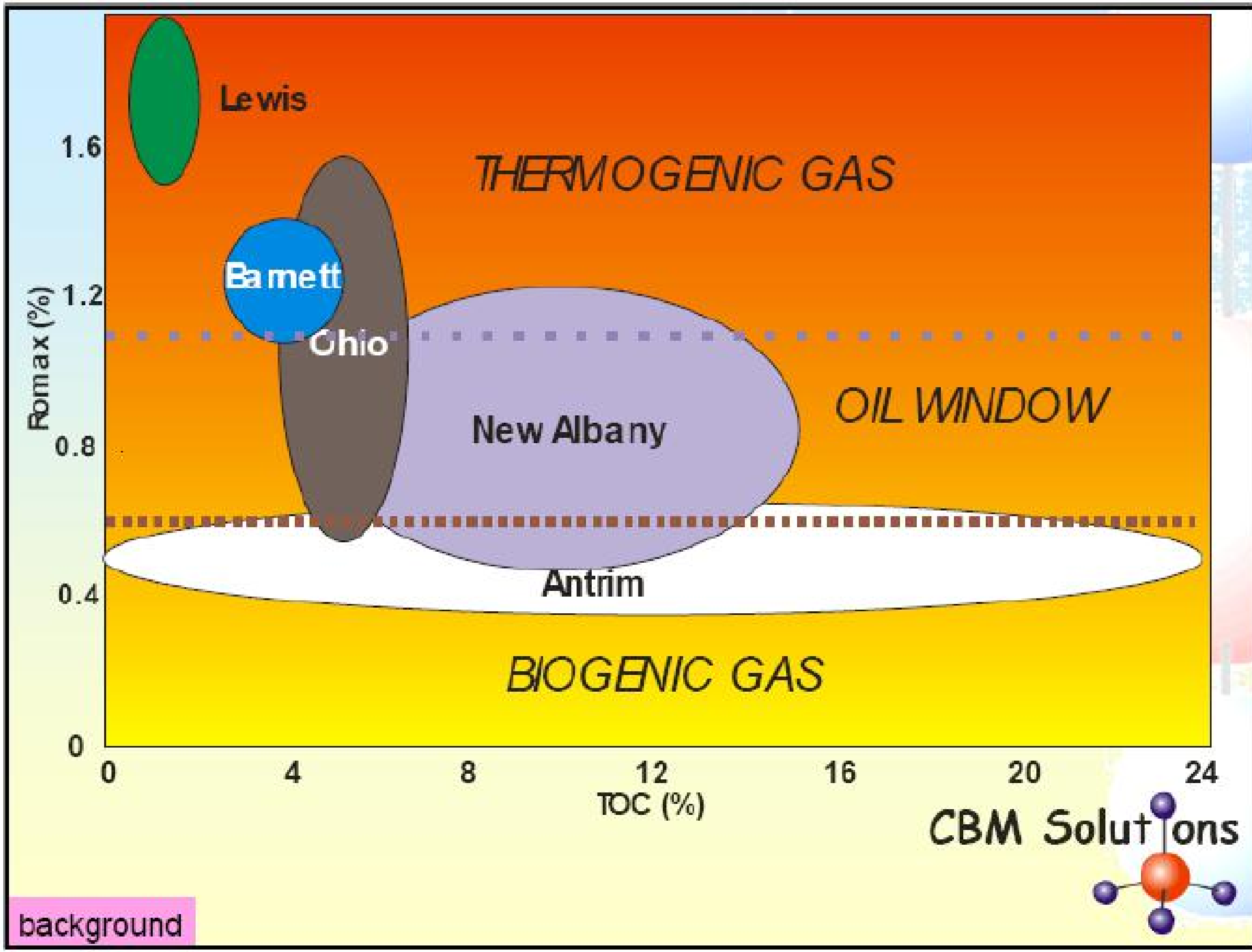
High mature to over-mature

Lacustrine shale



Low mature

Not published



Lewis
THERMOGENIC GAS
Barnett
Ohio
New Albany
OIL WINDOW
Antrim
BIOGENIC GAS
Romax (%)
0
0.4
0.8
1.2
1.6
0
4
8
12
16
20
24
TOC (%)
CBM Solutions
background

Kerogen Composition

- Type I kerogens: Rare because it limited to anoxic lakes and to a few unusual marine environments, but have high generative capacities for liquid hydrocarbons
- Type II kerogens: Several very different sources, including marine algae, pollen and spores, leaf waxes, and fossil resin; grouped together because all have great capacities to generate liquid hydrocarbons. Most found in marine sediments deposited under reducing conditions
- Type III kerogens: Composed of terrestrial organic material, normally considered to generate mainly gas
- Type IV kerogens: Mainly reworked organic debris and highly oxidized material of various origins, generally considered to have essentially no hydrocarbon-source potential

Source Rocks: Organic Matter Type

Gas shales and low permeability sands display a variety organic matter types OMT) ranging among Type I, II (oil prone), and III (gas prone). Not all shale gas is from gas prone organic matter type; the majority is from marine OMT.

Shale	Age	OMT
Barnett	Mississippian	Type II
Lewis	Campanian	Type III
Fayetteville	U. Mississippian	Type II or Type II-III
Antrim	M. Devonian to L. Mississippian	Type III
New Albany	U. Devonian	Type II
Ohio	Devonian	Type I and II
Alberta-Montana trend	Upper Cretaceous	Type II or Type II-III

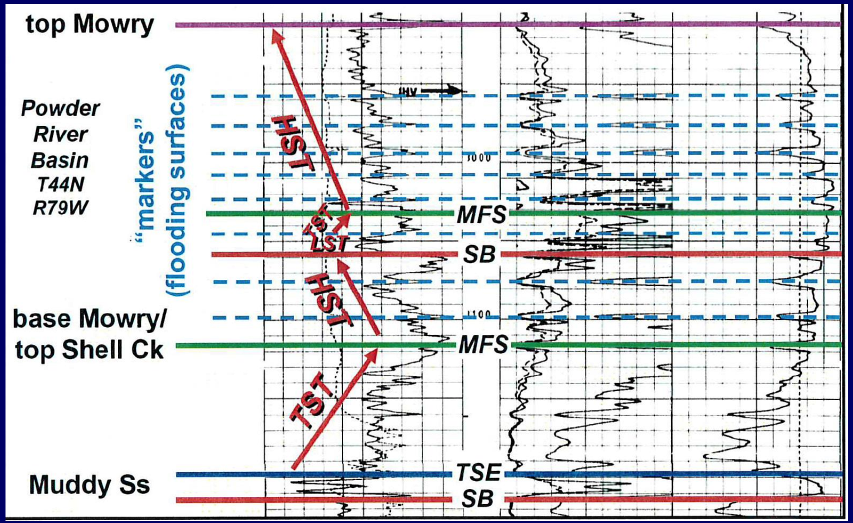
Source Rocks: Organic Carbon Content

TOC values up to 25%, but most producing thermogenic Shale Gas Systems have measured TOC values less than 5%.

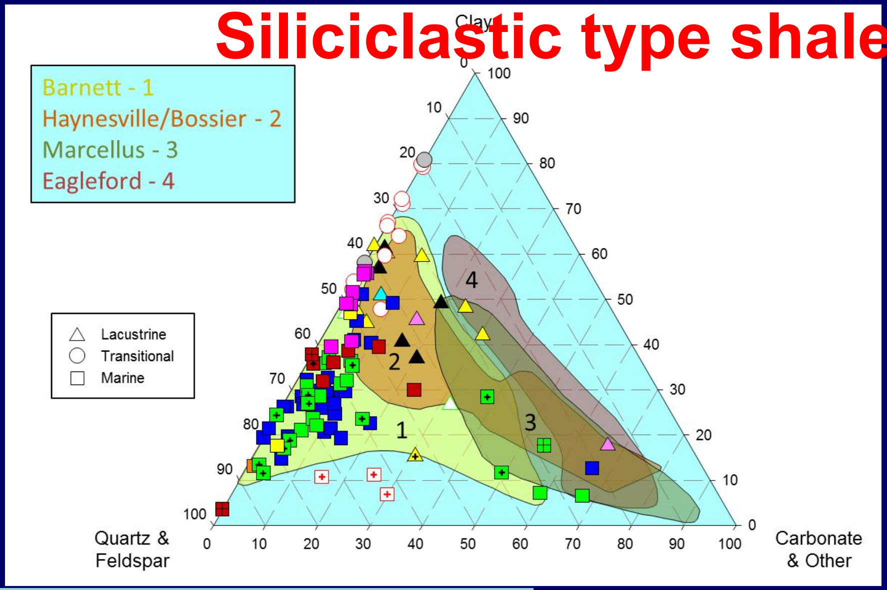
Shale	Age	TOC
Barnett	Mississippian	Av 3.5% Up to 20%
Lewis	Campanian	Up to 2.5%
Fayetteville	U. Mississippian	Up to 5.0%
Antrim	M. Devonian to L. Mississippian	Variable Up to 24%
New Albany	U. Devonian	Variable Up to 25%
Ohio	Devonian	3 to 11%
Alberta-Montana trend	Upper Cretaceous	Variable Up to 4%

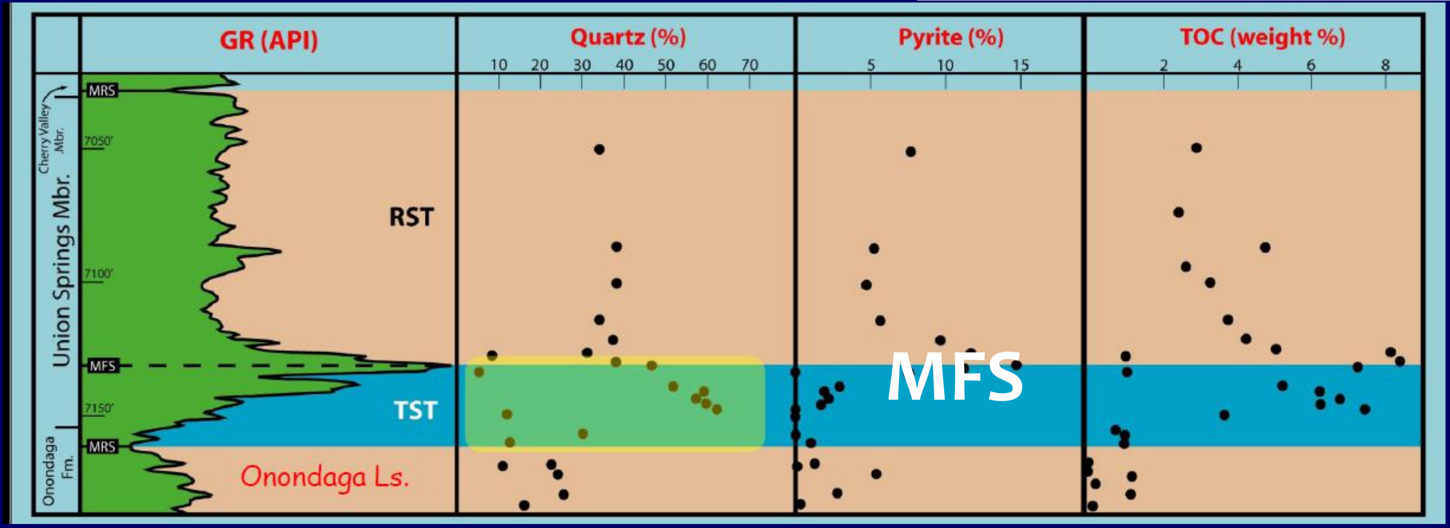
NOTE: SGS shales with low TOC values in many cases have been subjected to higher levels of organic maturity and thus measured (TOCm) values will be significantly lower than original (TOCo).

Distribution of Best reservoir interval within Sequence Framework



Cretaceous Mowry shale

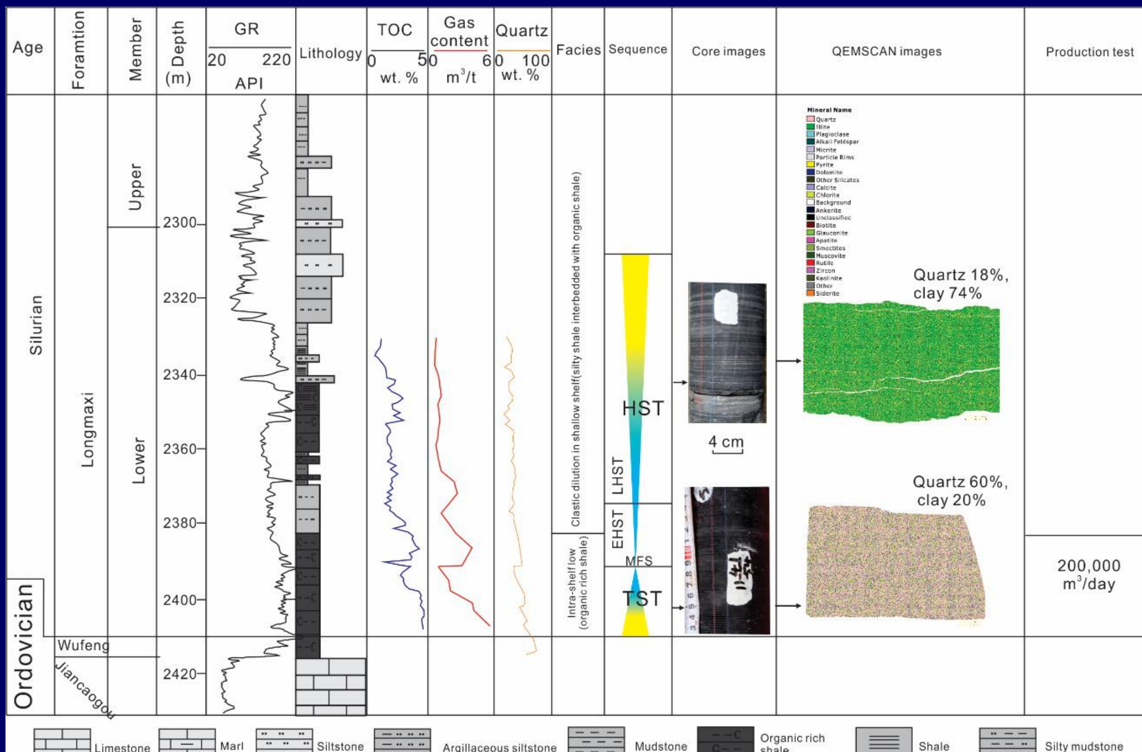




TST, High TOC, High Quartz

G.Lash and R.Blood, 2011

Marine Shale Gas Evaluation and Production



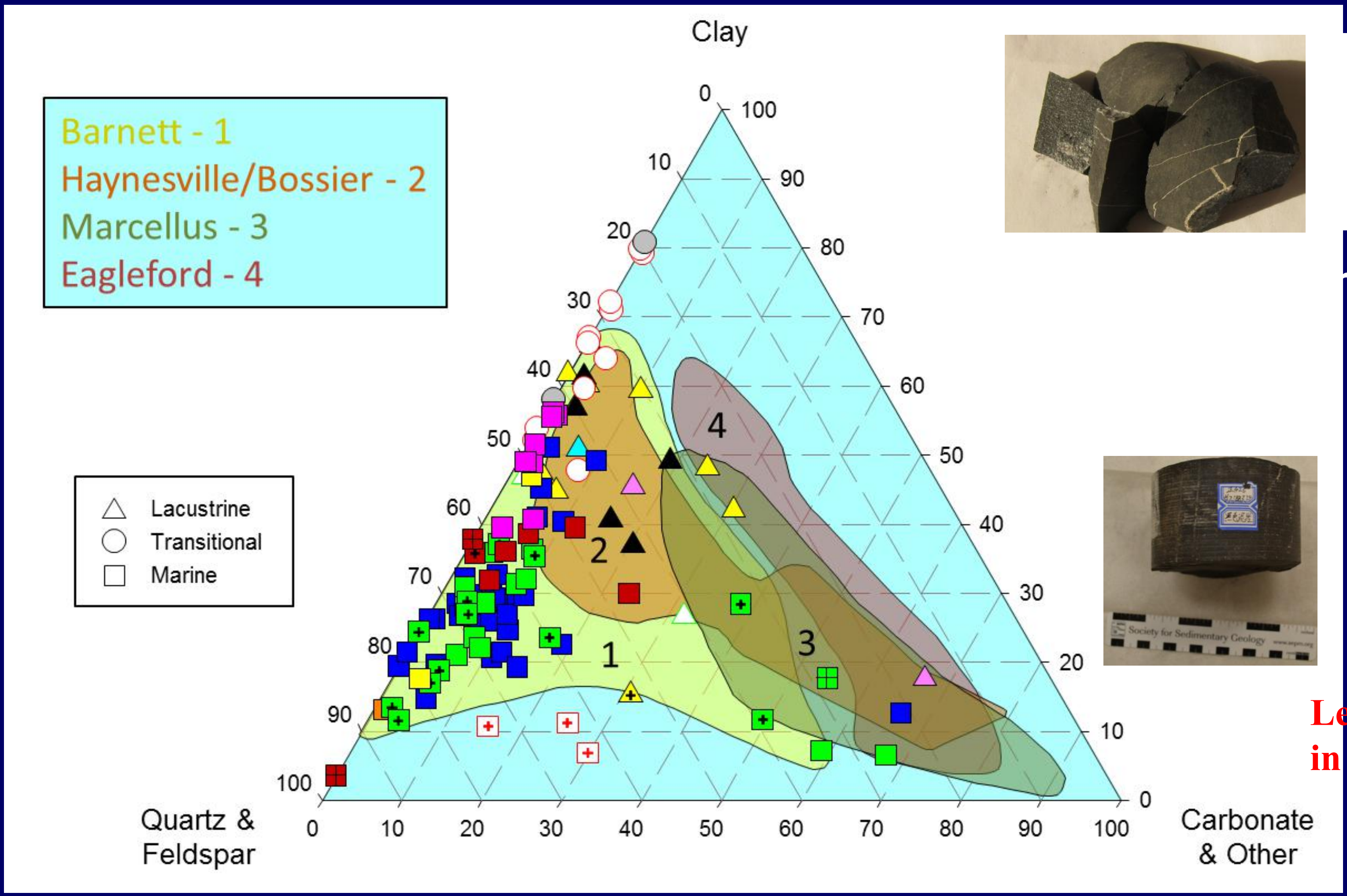
JY1 well in SE Sichuan Basin

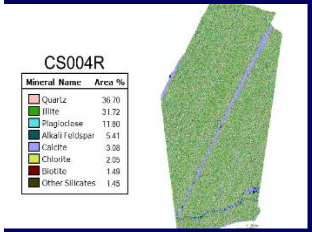
Similar to US Barnett siliceous shales, best reservoir interval at organic rich siliceous shale interval (geology), Commercial production using horizontal well and slick water hydraulic fracturing (engineering);

Natural fractures does not play role in production

Application of lessons learned from US shales

Mineralogy VS Depositional Settings for typical China and U.S. Shales



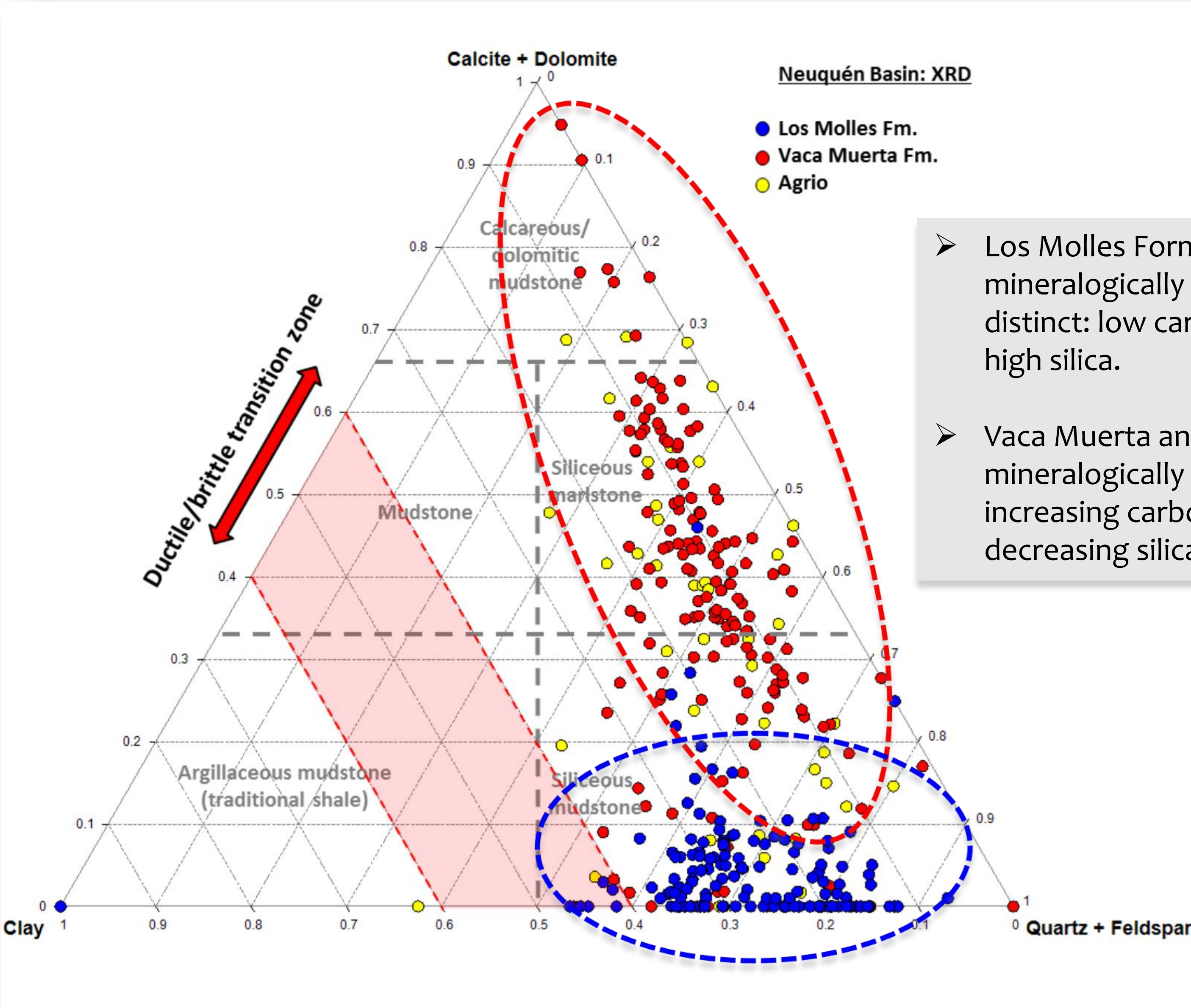


ral fractures

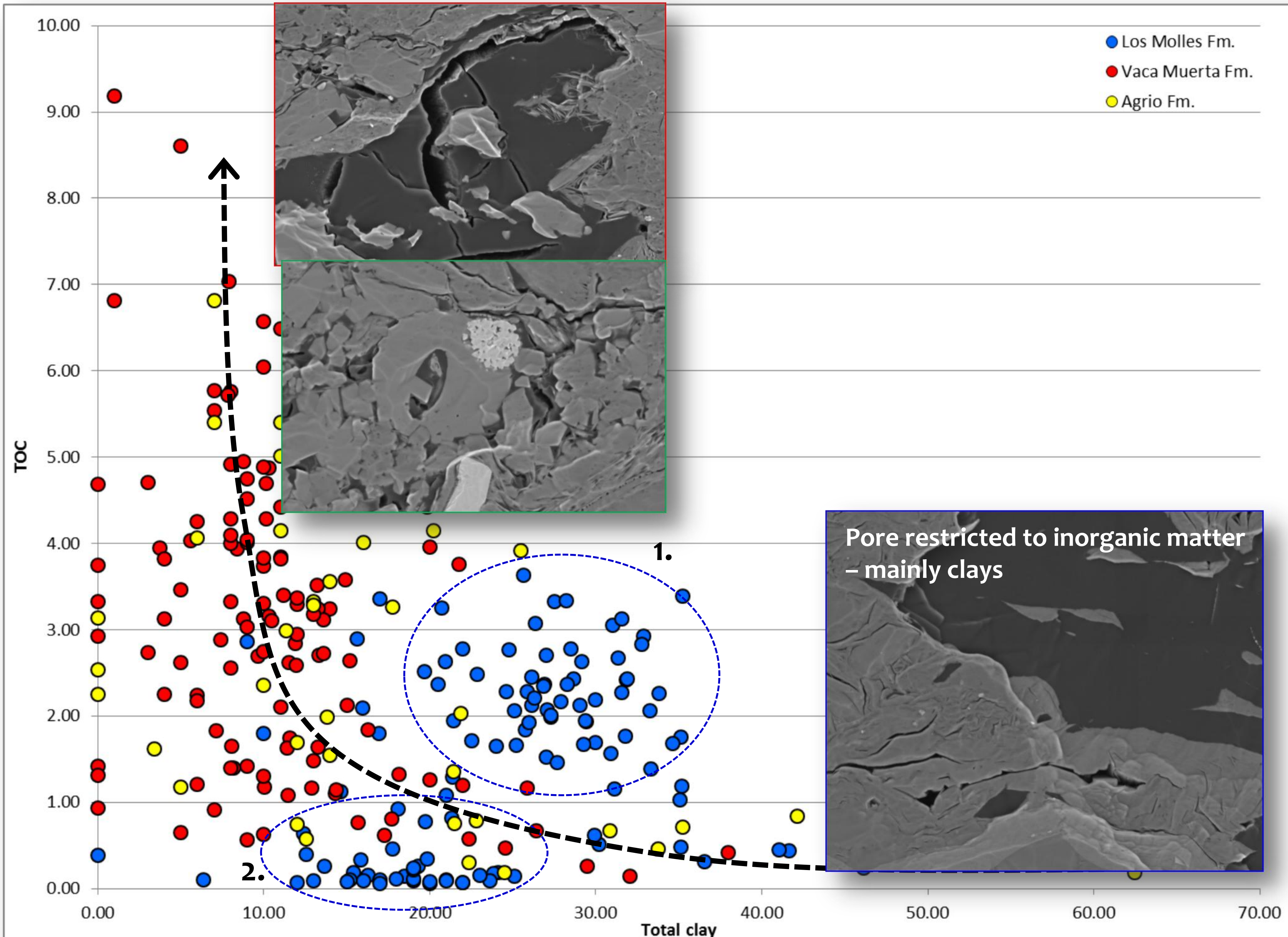
Less to no fractures in lacustrine shale

Is organic-rich and quartz-rich prerequisite for shale reservoir?

XRD



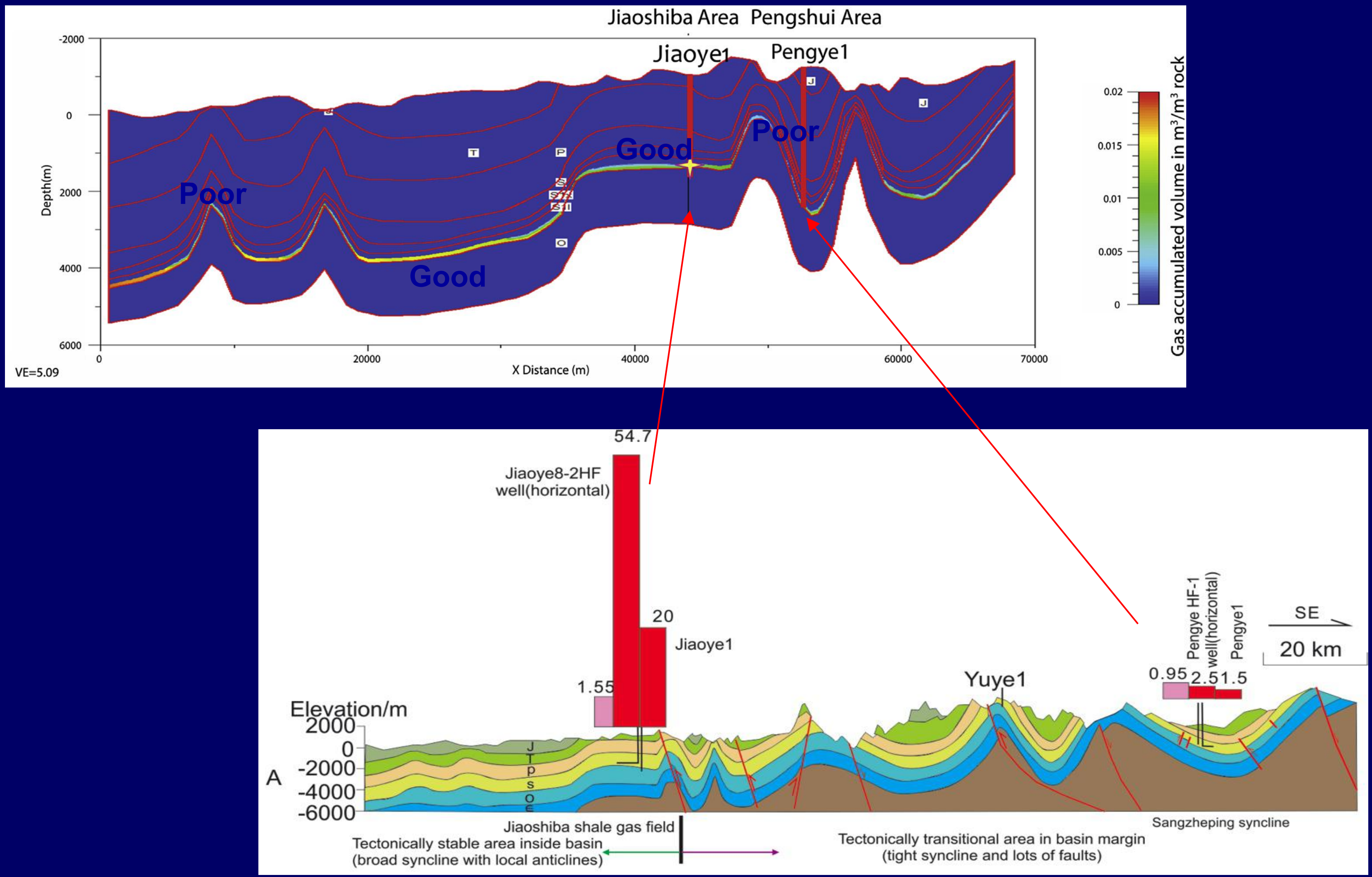
- Los Molles Formation mineralogically distinct: low carbonate, high silica.
- Vaca Muerta and Agrio mineralogically similar: increasing carbonate, decreasing silica.



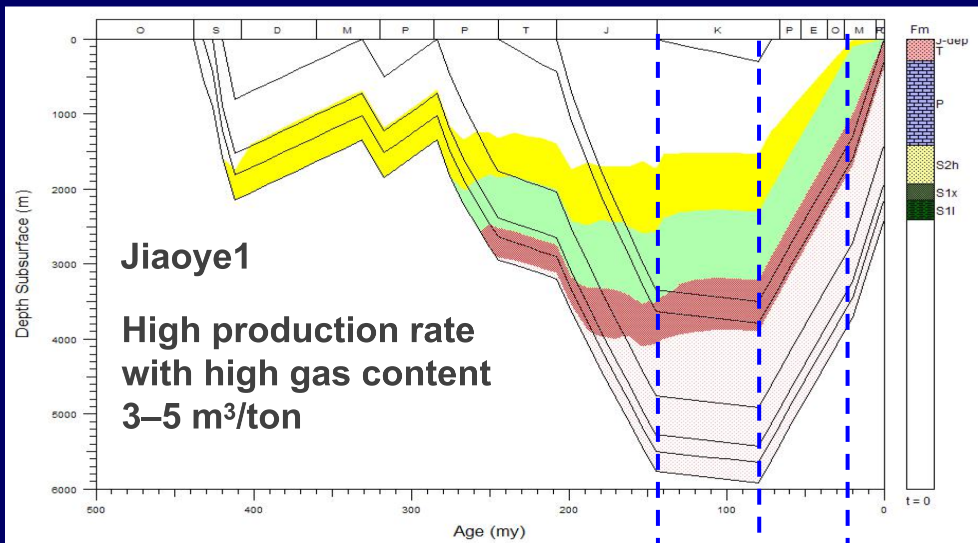
Los Molles Fm.
Vaca Muerta Fm.
Agrio Fm.
TOC
Total clay
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
10.00
20.00
30.00
40.00
50.00
60.00
70.00
1.
2.
Pore restricted to inorganic matter – mainly clays

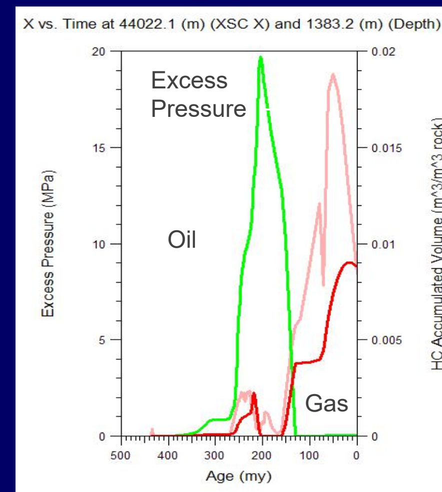
Shale Migration and Accumulation

Simulation of Tectonic Effects on Shale Gas Accumulation

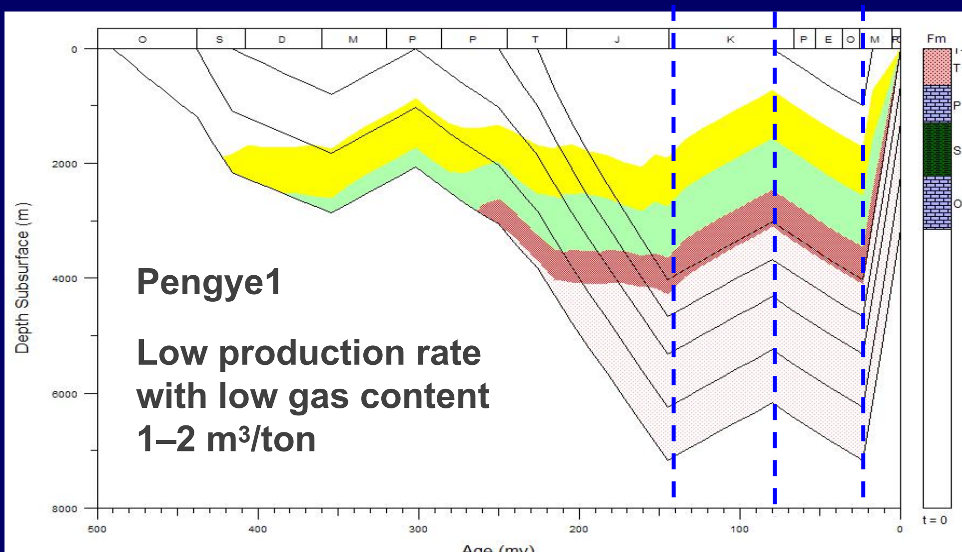


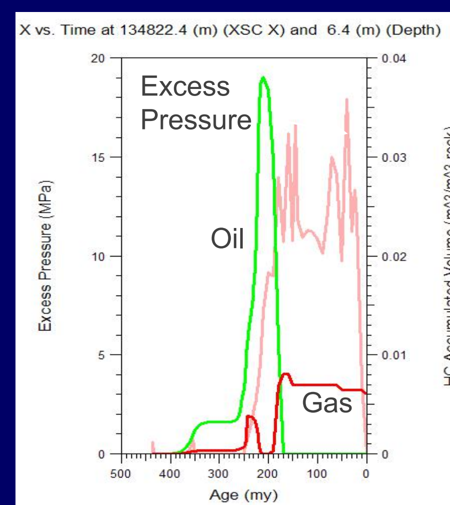
Simulation of Tectonic Effects on Shale Gas Preservation





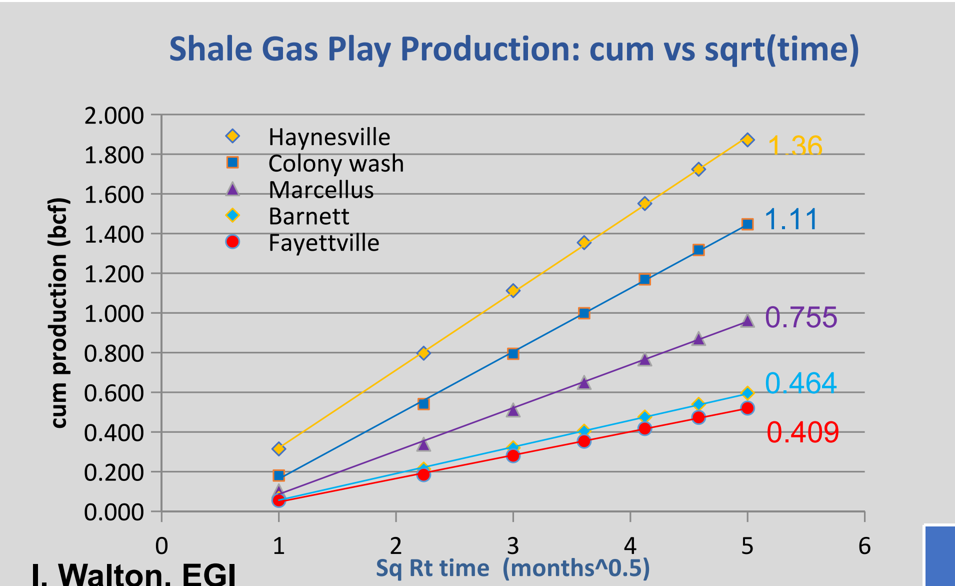
Jiaoye1 well
Partial overpressure & shale gas were released due to uplifting. Still overpressured



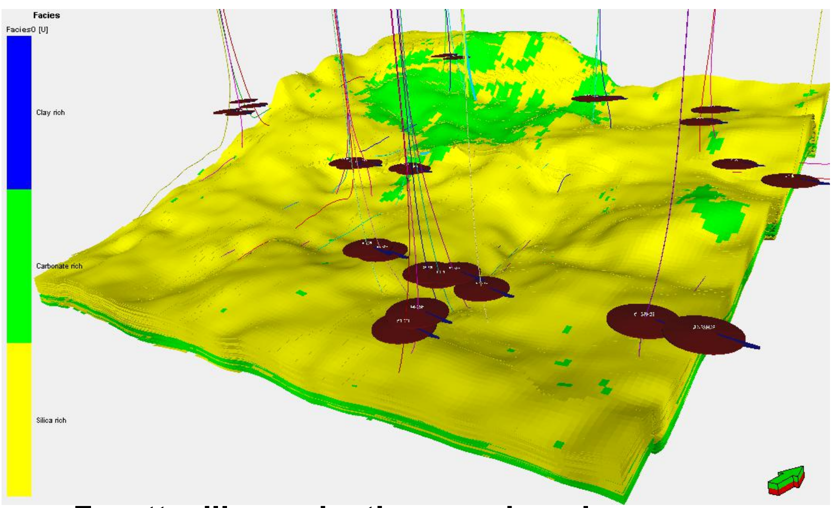


Pengye1 well
Multi-stage extensive uplifting & erosion unloaded the overburden. Overpressure was totally released resulting in low gas content.

Geologic Control on US Shale Production



High production from sweet spot with high TOC, high porosity, high pressure, high brittle mineral content, etc.



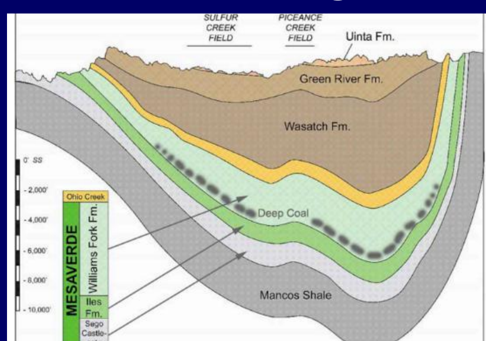
Fayetteville production vs mineralogy

Shale	Haynesville	Barnett	Fayetteville
TOC(%)	3	4.5	2-5%
Pressure gradient (psi/ft)	0.95	0.526	0.42
Quartz content(%)	10-40%	41	40-60%
Porosity(%)	10	6	4

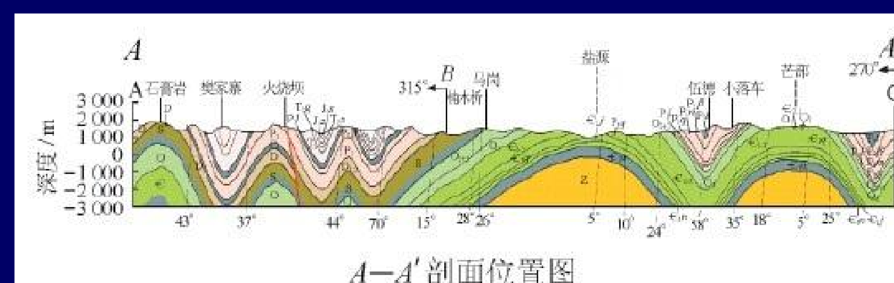
data from M. Roth, 2010 and various resources

Tectonics-Play Key Role

Photo courtesy of EcoFlight / SkyTruth

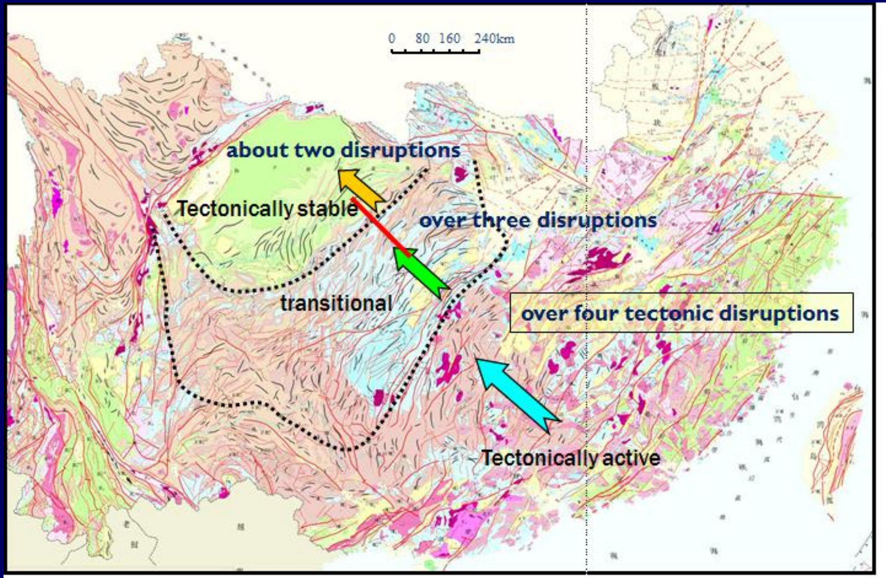


Piceance Basin, Illustration for US geology



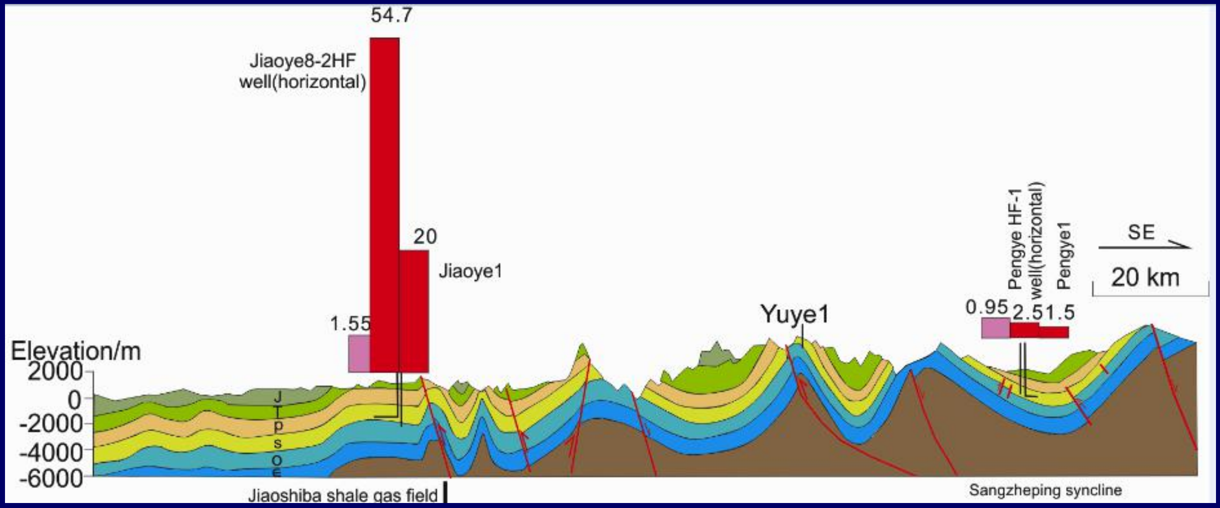
S Sichuan Basin, China

China Marine Shales –
Complex tectonics influence development



Complex tectonic activities in China may have disrupted shale gas accumulation;

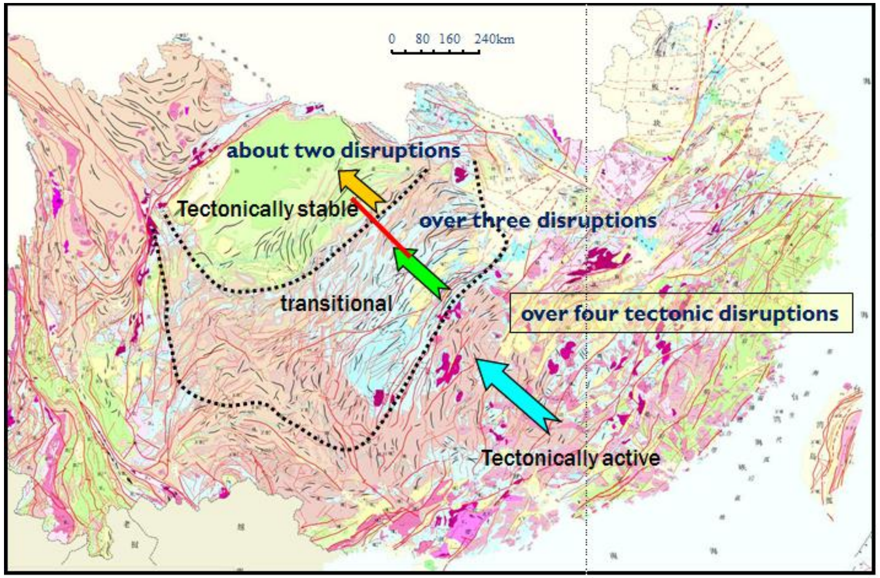
it also influence hydraulic fracturing.



Pressure coefficient

Daily production x10^4 m^3/day

China Marine Shales –
Complex tectonics influence development



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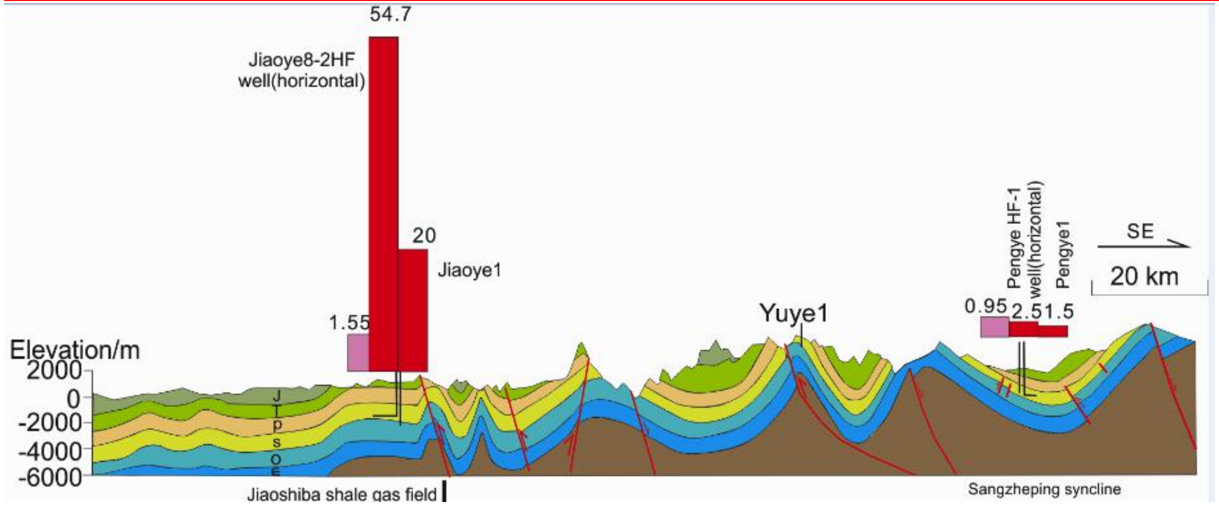
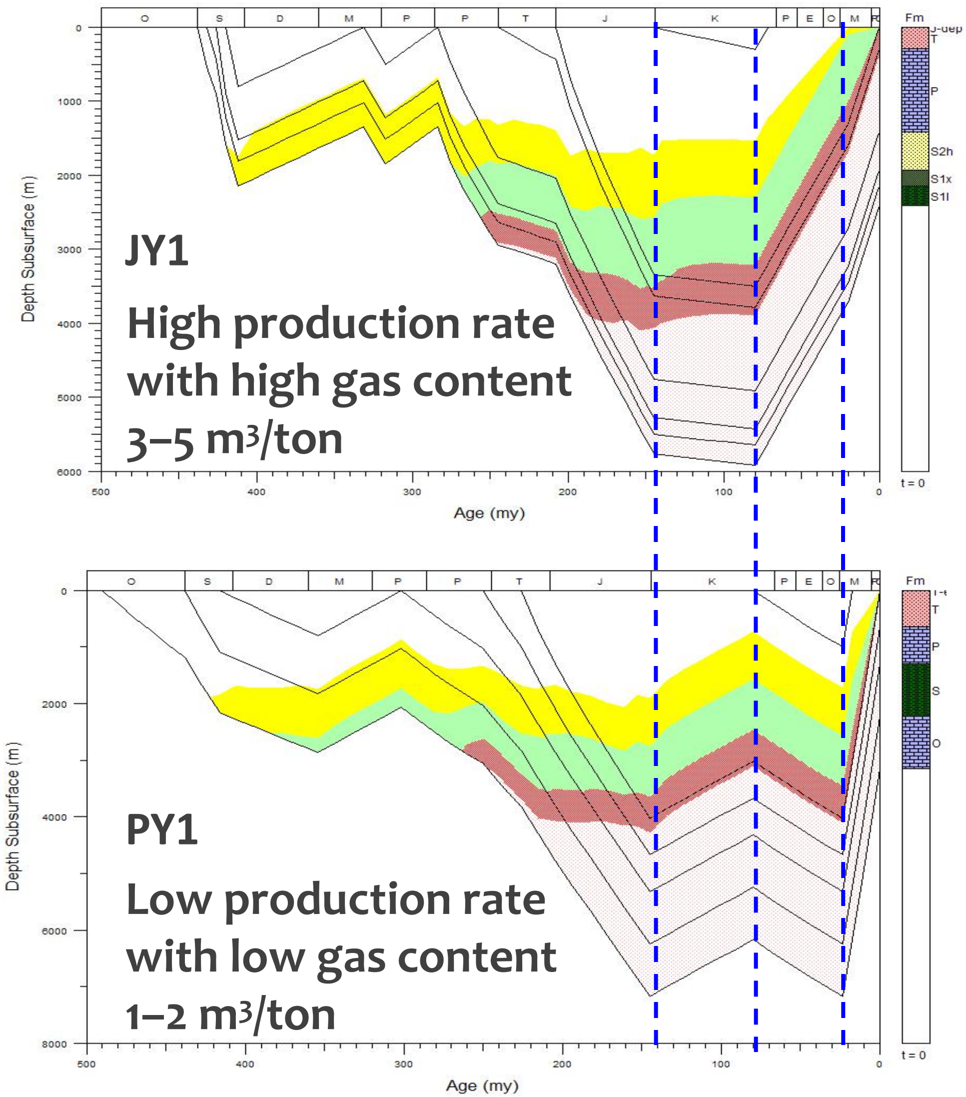
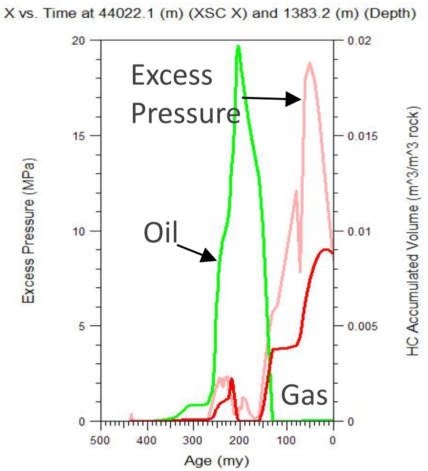


Pressure coefficient

Daily production x10^4 m^3/day

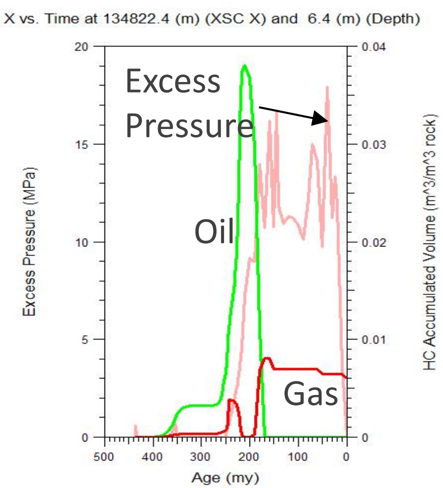
Tectonic Effects on Gas Retention





JY1 well

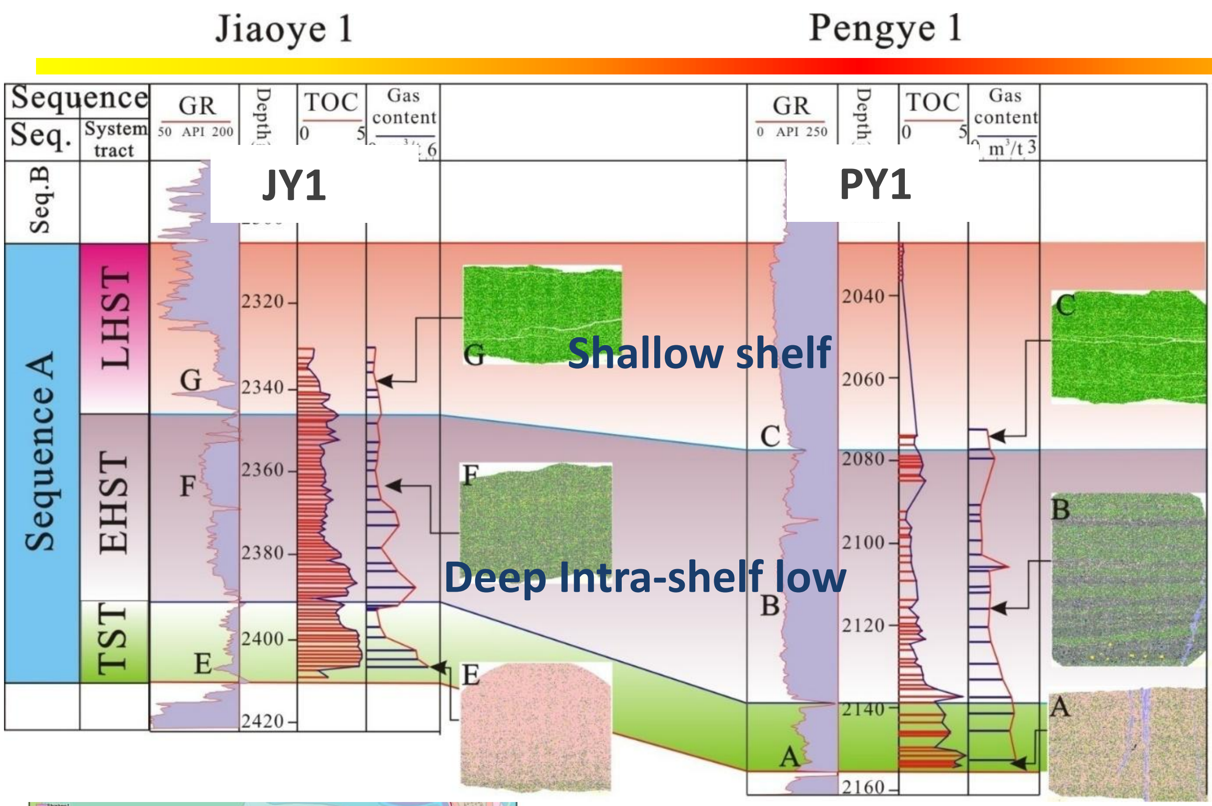
Partial overpressure & shale gas were released due to uplifting.



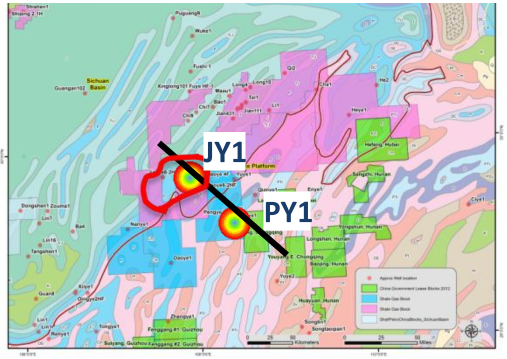
PY1 well

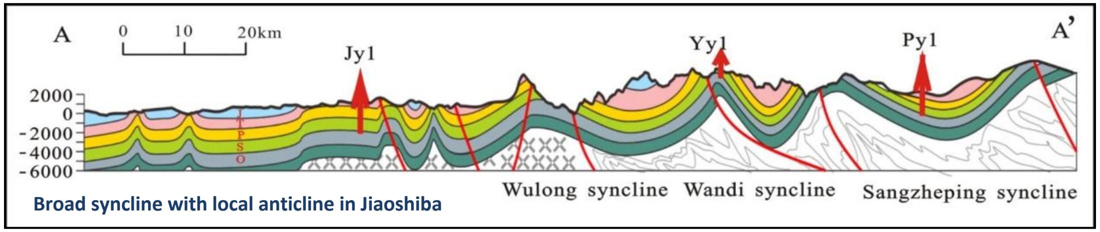
Multi-stage extensive uplifting & erosion unloaded the overburden. Overpressure was totally released resulting in low gas content.

Influence of Tectonic Setting on Gas Content



Gas content in Silurian Longmaxi marine shale with similar TOC decreases from tectonically stable area to tectonically active area

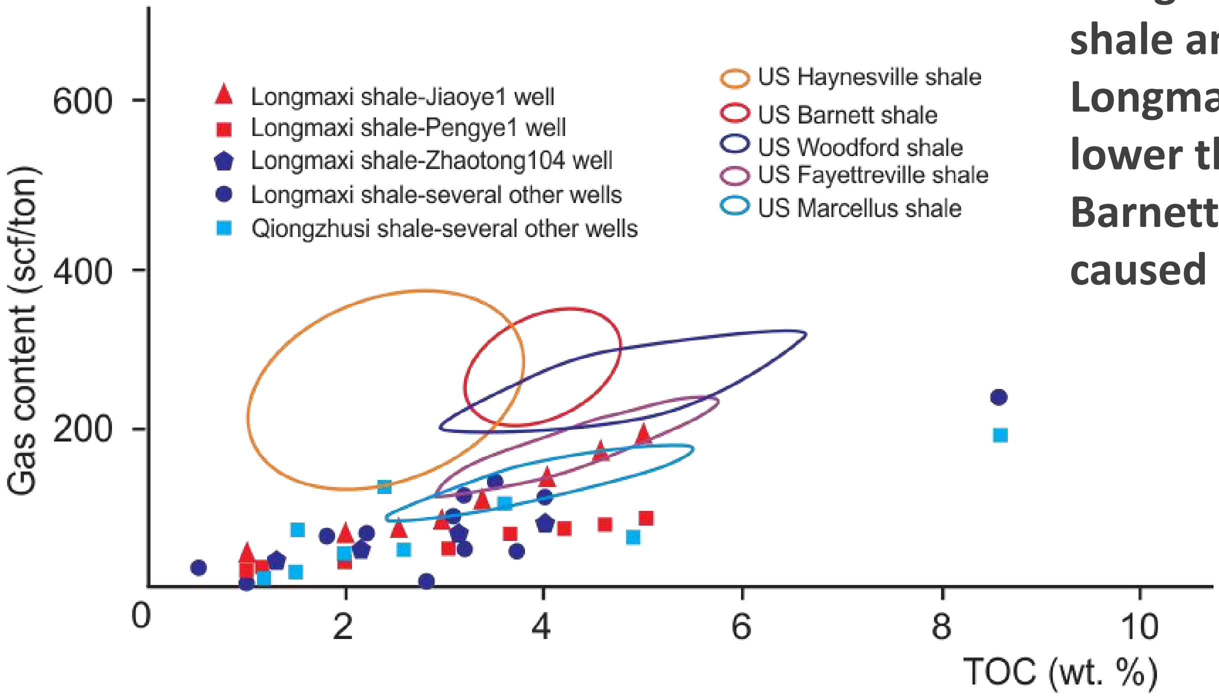




Tectonically stable area, high gas content (3–5 m^3/t)

Tectonically transitional area, low gas content (1–2 m^3/t)

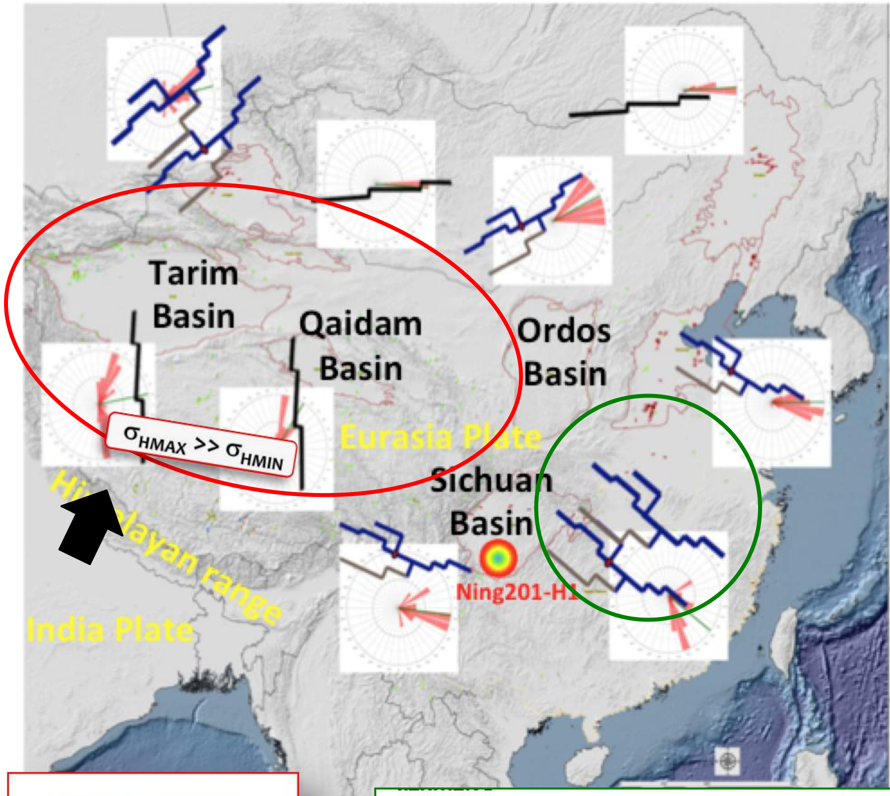
Influence of Tectonic Setting on Gas Content

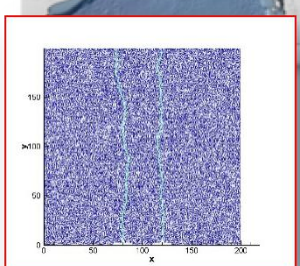


Data for the Jiaoye1 well is from Guo (2013). Data for typical U.S. marine shales are from Hill and Nelson, 2000, Mavor, 2003 and Jarvie, 2012.

The gas content of Cambrian Qiongzhusi shale and Silurian Longmaxi shale in China is generally lower than that of Haynesville & Barnett shale plays & may be caused by active tectonics in China

Tectonic & Stress Field Effects on Hydraulic Fracturing





$\sigma_{HMAX} >> \sigma_{HMIN}$

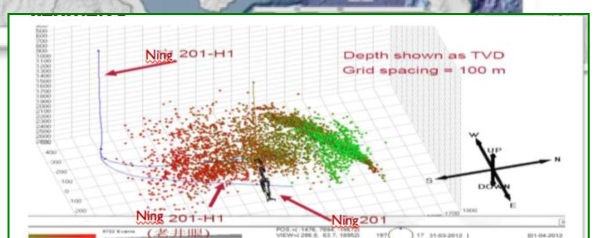
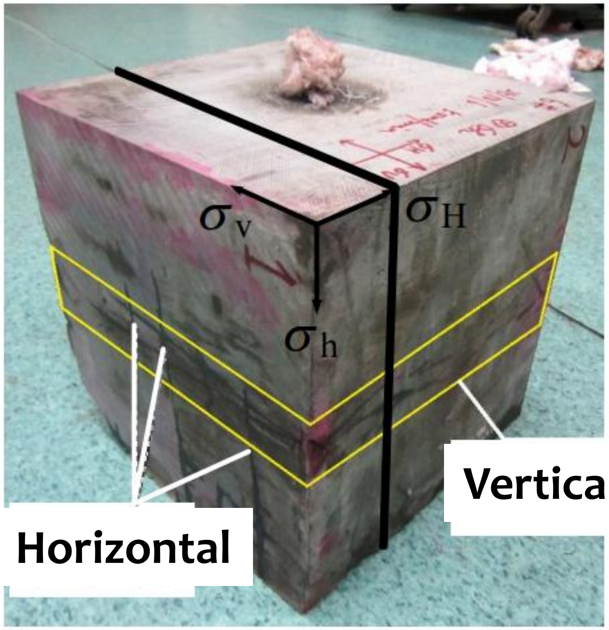


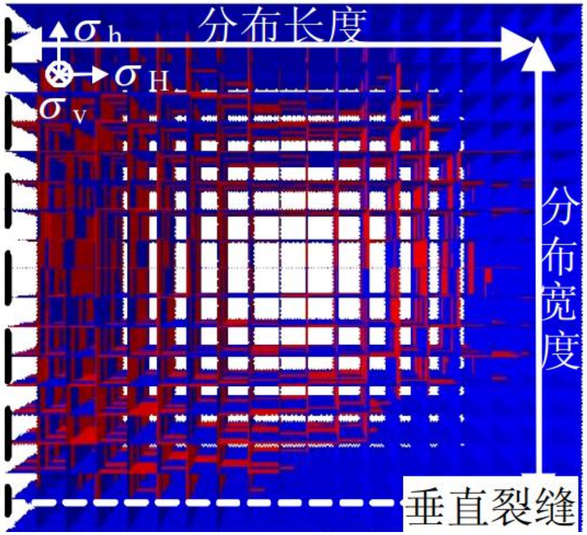
Fig. 18—Microseismic events for all 10 stages.

SPE 167006, Zonggang lv et al., 2013

- **Hydraulic fracturing may not form complex fracture networks in the *Tibetan Plateau area, Tarim, West Sichuan Basin, and* maybe local areas in Qaidam and Songliao Basins due to large stress anisotropy.**
  - **South & Southeast Sichuan Basin areas in UYZ & areas in MYZ and LYZ are less influenced by the collision between India &Eurasia.**
  - **Stress field is $\sigma_{H,MAX}$ ~> $\sigma_{H,MIN}$**
  - **Small far-field stress difference cannot compete with the stress shadow effects which may lead to complex fracture geometry**

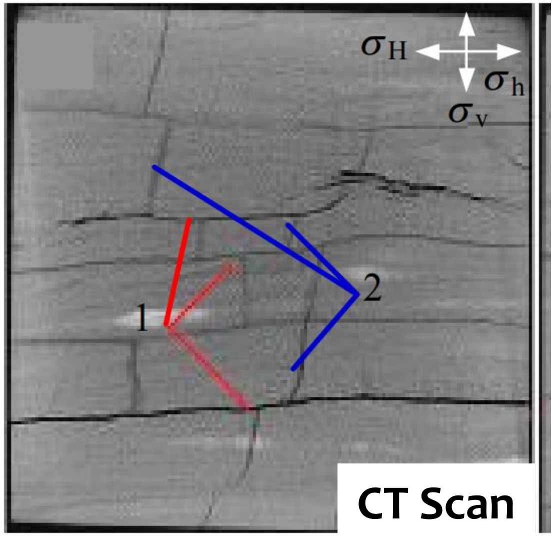
Hydraulic Fracturing Lab Test and Simulation for Longmaxi Shale in SE Sichuan Basin

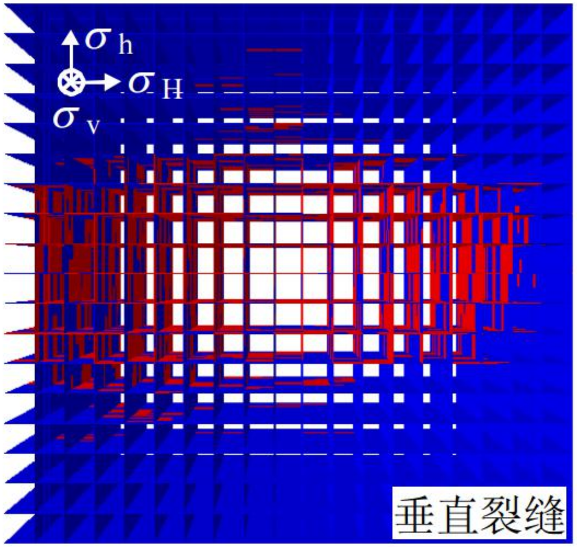




Stress contrast: 5 MPa

Courtesy of Y. Zhang

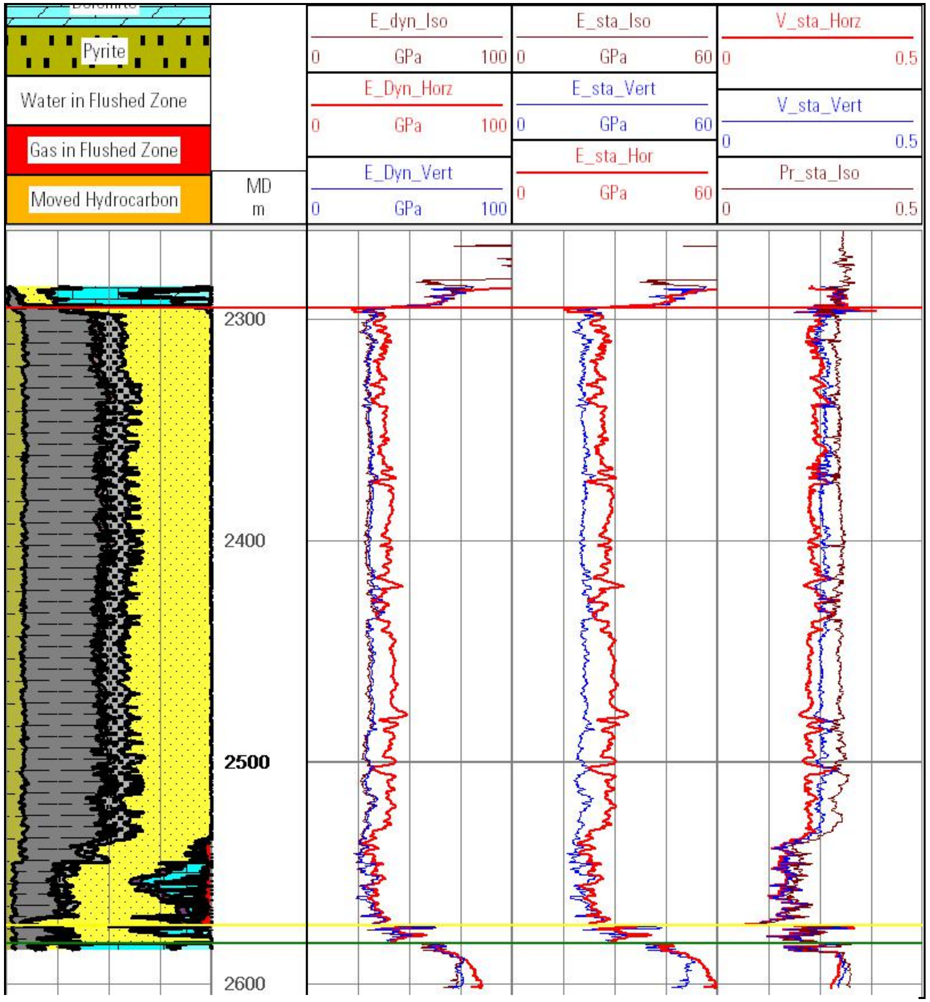


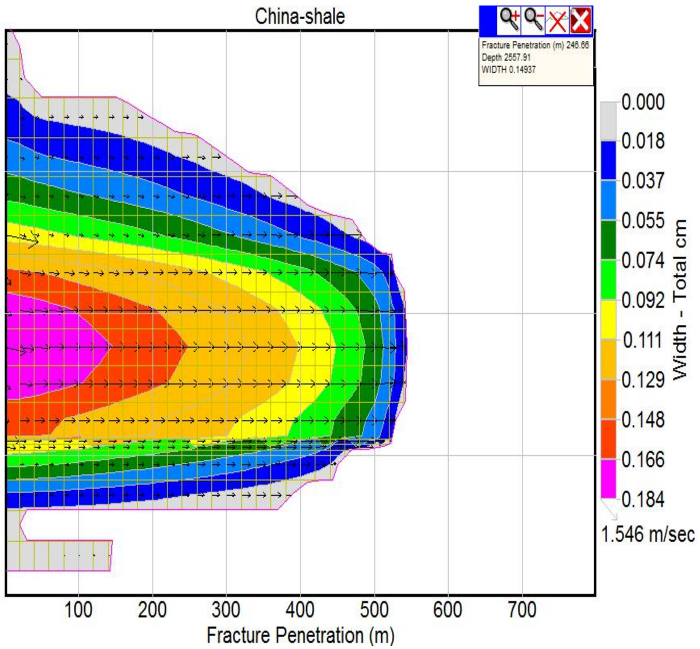


Stress contrast: 14 MPa

Fracture propagation simulation results

Hydraulic Fractures Containment Example and Simulation





Silurian Marine Longmaxi Shale's geology
And engineering parameters
suitable for hydraulic fracturing

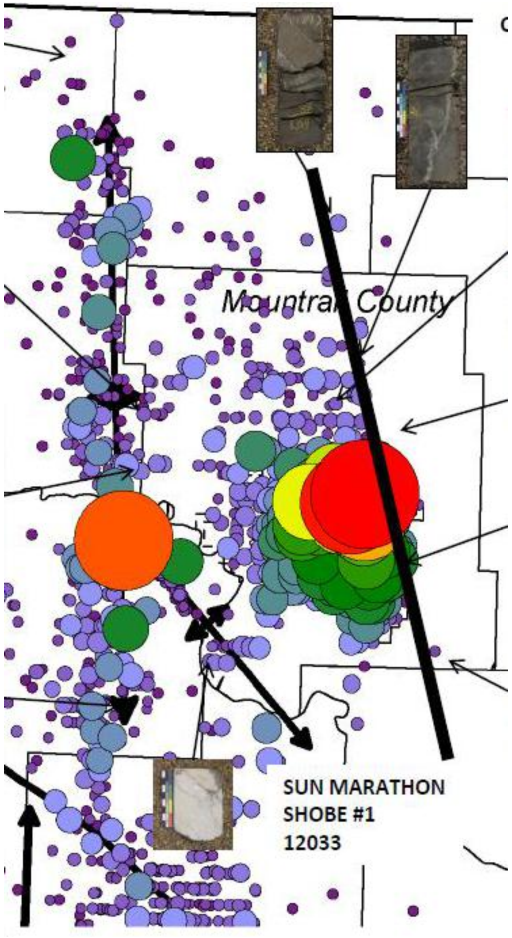
Role of Natural Fractures

Barnett

K. Bowker, 2008

Natural fractures may not or may play key role in storage and production

Bakken

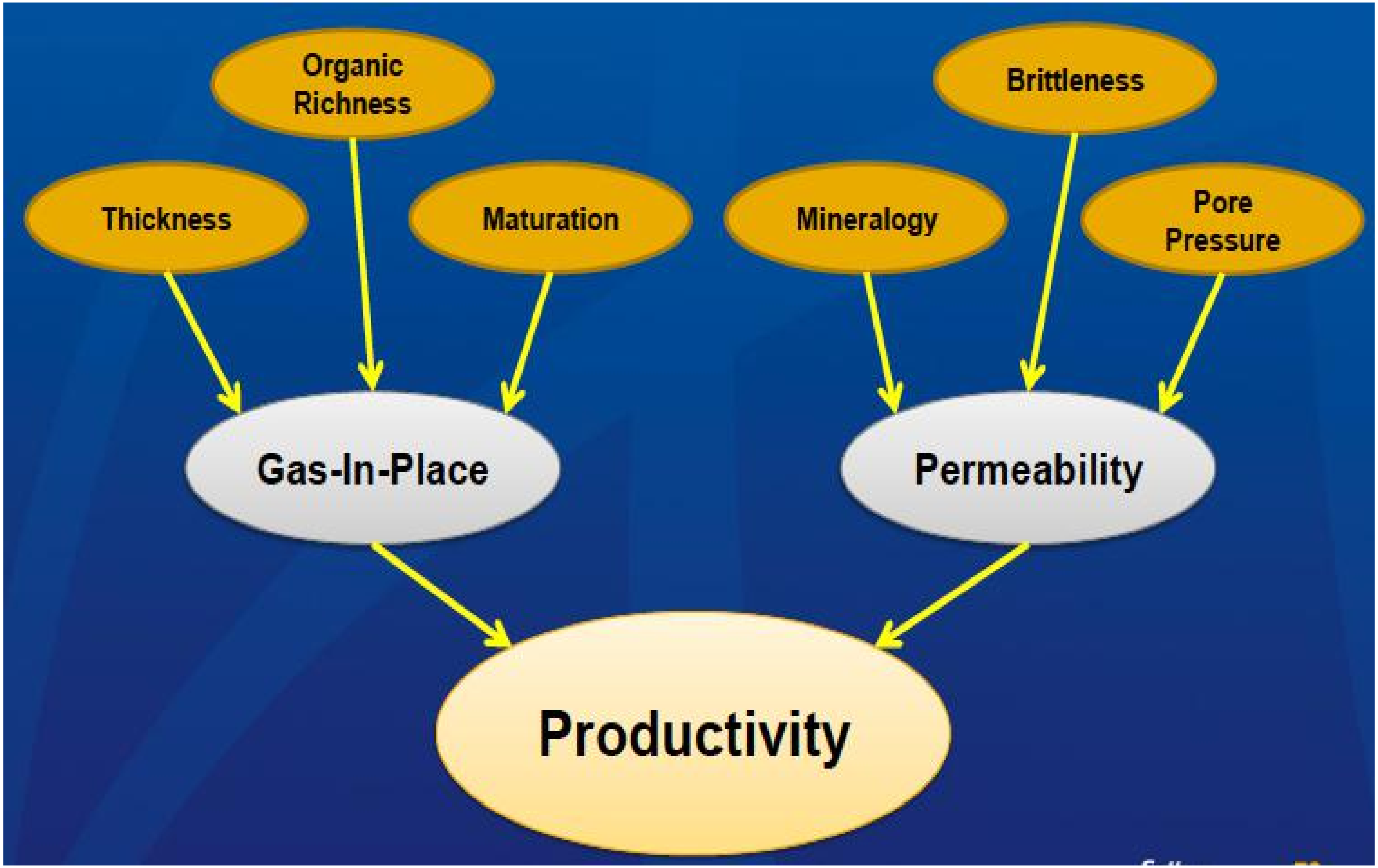


Nordeng, et al, 2010, NDGS (AAPG)

Larger bubble=higher production

What Makes A Good Shale Gas Play?

- **TOC >2%:**
  good source rock
- **Maturation:**
  "gas" window - 1.1 to 1.4 Ro, abundant gas
- **Low hydrogen content:**
  gas prone.
- **Moderate clay content:**
  less than 40%-brittle
- **Thickness:**
  greater than 100 ft.
- **Good gas content:**
  greater than 100 scf/ton.
- **Hydraulic fracture barrier.**



Organic
Richness
Brittleness
Thickness
Maturation
Mineralogy
Pore
Pressure
Gas-In-Place
Permeability
Productivity

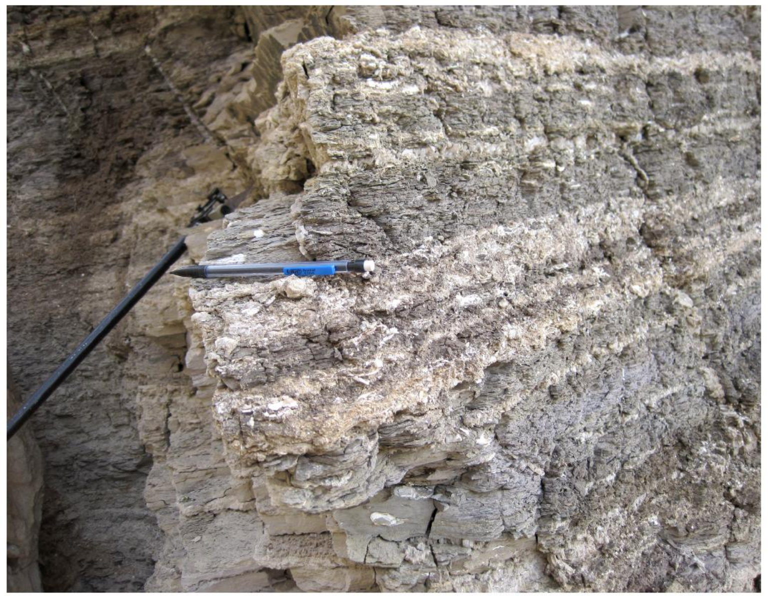
Ideas of What to Look For In a Gas Shale?

Characteristic	Core Producing Area Range	Minimum for Development	Importance
TOC	3 to >10	>0.5	High
% Silica and/or calcite	>40%?	>25%	Mod/High
Maturity, Vitrinite Reflection, %	1.0 to >2, >1.4 for dry gas	1.4	High
Shale thickness, ft	100 to >1000	>>100 ft	High
Gas in Place, bcf/sq mile	30 to 350	>25	High
Matrix Permeability, md	E-4 to 0.001 md	>0.00005 md	Low
Matrix Porosity (effective)	<2 TO >8%	>4%	High
Depth of pay	400 to 17000	3000 to 12000?	Mod/High
Modulus of Elasticity	3MM to >9MM	Depends on frac barriers	High
Nat. Frac Presence	Yes, open during production	Same	High
Boundaries for Frac	Yes	Absence requires special fracs	Mod/High
Gas Content scf/ton	<30 to >300	>80	High
Gas % in pore	>50%	>30%	High
Gas % adsorbed	<50%	<70%	Moderate
Typical prod rates, scf/d	0.3 to >5 mmscf/d	1.5 to >2MM	Highest
Water saturation	0.1 to <0.35	<0.25	High
Oil Saturation	Low	<0.1	High
Horizontal well length, ft	500 to >4000 ft	>1500 ft	High
Horiz direction rel to frac dir.	Transverse	Between 60 and 135º	High
Fracture needs	Rubblize the zone	Rubblize the zone	High
Dewatering (frac cleanup) Time	0.1 to 1 months	0.1 to 2 months	Moderate
Decline Rates	50% 1st yr	65% 1st yr	Mod/High
Est. Ultimate Recovery, EUR	>1 to 3 bcf	1 to 2 bcf	Moderate

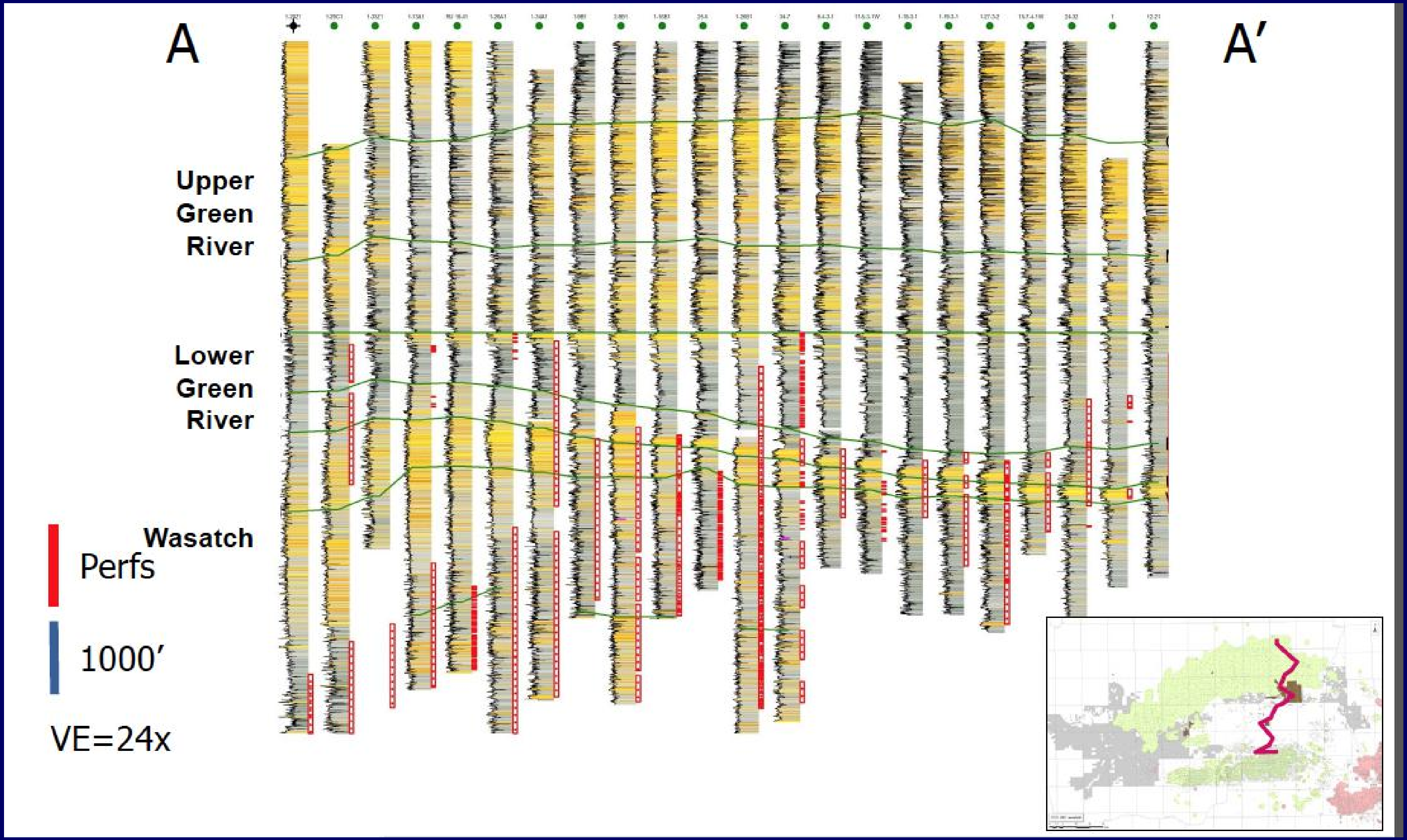
Quick Comparisons of Shales From Which Gas Production Is Possible

Pay Character	Barnett	Marcellus	Fayetteville	Woodford	Devonian	Antrim	N Albany	Lewis
Basin	FW	Appalachia	Arkoma	Arkoma	App	Michigan	Illinois	San Juan
Location	TX	PA,WVA	AR	OK	KY, NY, PA, WV	MI, IN, OH	IN, KY	CO, NM
Depth (ft)	6 to 9000+	4 -10,000’	1500 to 6000’	6 to 12,000’	2 to 8000+	0.6 to 2K+	0.5 to 2K+	3 to 6000
H, thick: gross/net	100+: 50%	50 to 300	50-550: 50%	200 to 350	30 to 300: 40%	160: 40 - 60	180: 40 - 60	3000:0.35
Modulus, psi	7 to 9MM	4 to 7MM	3MM	3 to 5MM	3 to 7MM			
BHT F	180-210	150-200F	120 to 160		100 to 140	80	80	130-170
Press Grad, psi/ft	0.4 to 0.5	0.3 to 0.55	0.35 to 0.4	0.43 - 0.46	0.2 to 0.4	0.35	0.43	0.25
Maturity, Ro, %	1.4+ gas	1.4 to 2+	1.9 to 5	1.1 to 3	0.9 to 2	0.4 to 1.6	0.6 to 1.6	1 to 1.3
TOC, wt %	1 to 5	5 to 12	5 to 15	10 to 20	3 to 20	3 to 20	3 to 20	0.5 to 2.5
Total Porosity %	1-8	1 to 7	1 to 5	1 to 5+	2 to 5	2 to 10	5 to 15	0.5 to 5
Sw	0.1 -0.25	0.1 - 0.25+	0.1 to 0.2	0.1 to 0.25	0.1 to 0.25	0.1 to 0.3	0.1 to 0.3	0.1 to 0.8
Gas Cnt, scf/ton	100-500	80 to 250+		150-225	60 to 100	40 to 100	40 to 80	15-45
Adsorb Gas, %	20	40	30	30	50	70	40 to 60	15 to 40
VWell Cost, MM$	1.6 MM	1. MM	1.3 to 1.6			0.150	0.150 -0.200	0.3 to 0.5
V Gas IP/6mo, MM	0.3 to 1	0.1 to 1	0.5 to 0.8			40 – 500/?	10-50/?	
HWell Cost MM$	2.2	2.0?	2.9 to 3					
H Gas IP/6mo	0.8 to 3	0.5 to 3	0.8 to 2					
Water Prod BWPD	10 -100+	10 -100+	0		0	20 to 100	5 – 500	0
Well spacing	80-160	80 to 160	40 to 80		40 to 160	40 to 160	80	80 to 320
GIP BCF/Section	30 to 40	30 to 50	55 to 65		5 to 10	8 to 16	7 to 10	90
Basin Resources (TCF)	25 to 250	275+	10 to 15		225	12 to 20	2 to 80	100
EUR (BCF/well)	2 to 5	2 to 4+	0.6 to 0.9					0.3 to 0.5
Recovery Factor %	8-15	10 to 15	10 to 15	UNK	10 to 20	20 to 60	10 to 20	5 to 15

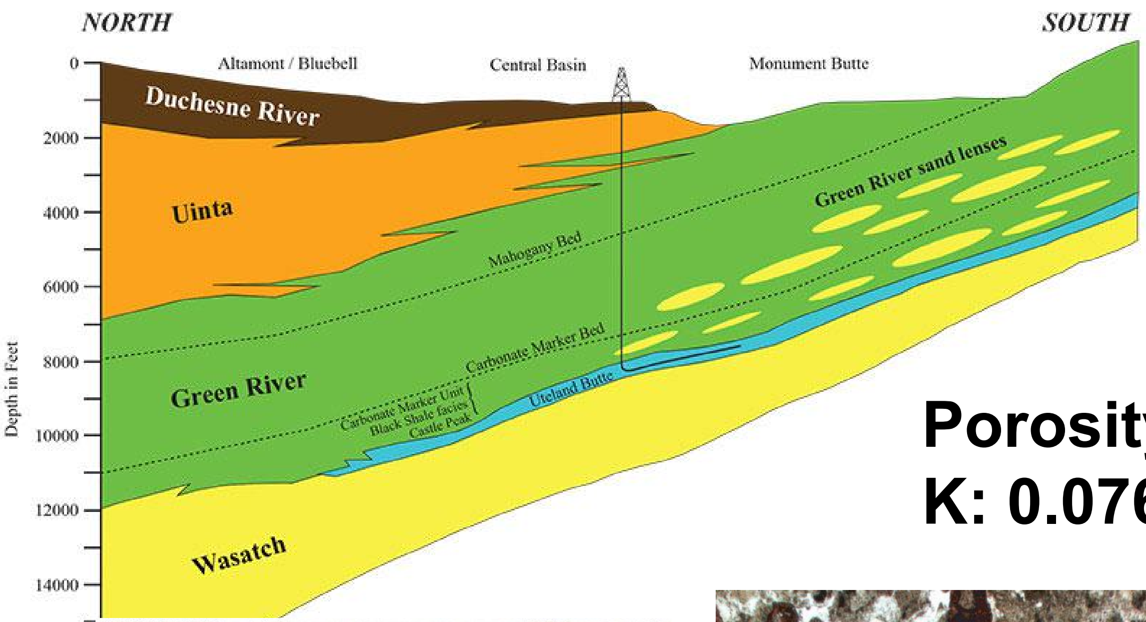
Heterogeneous Green River Shale



Heterogeneous Lacustrine Plays



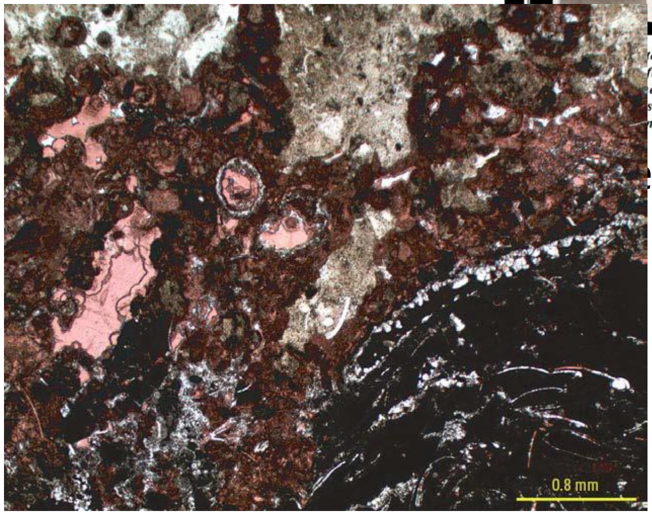
Resource Play-mainly tight oil from fine grained carbonate reservoir



Porosity:20%
K: 0.076mD

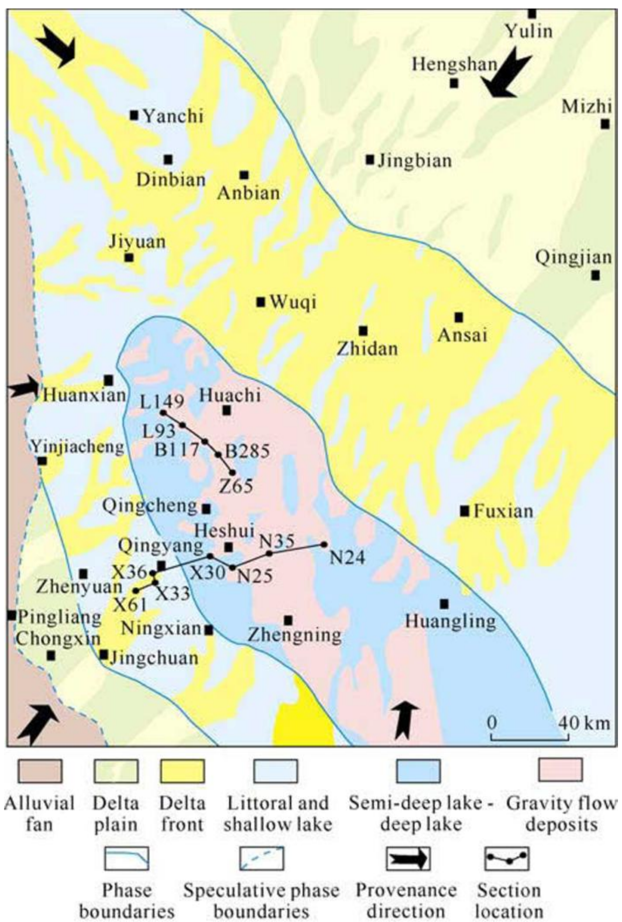
...te core from the Bill Barrett 14-1-46 well. The horizontal drilling
...ft light brown dolomitic interval. Porosity in this interval ranges
...eability averages 0.06 mD. The dolomite is interbedded with
...s and limestones averaging between 1% and 3% TOC. Note the
...nts indicating deposition in a freshwater lacustrine environment.

...el Vanden Berg, 2013

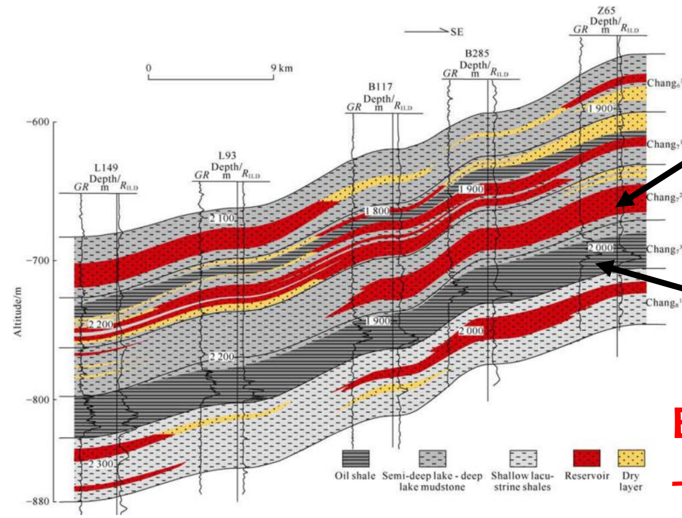


Hybrid Plays Example-Ordos Basin, NW China

Triassic Chang7 SR interval



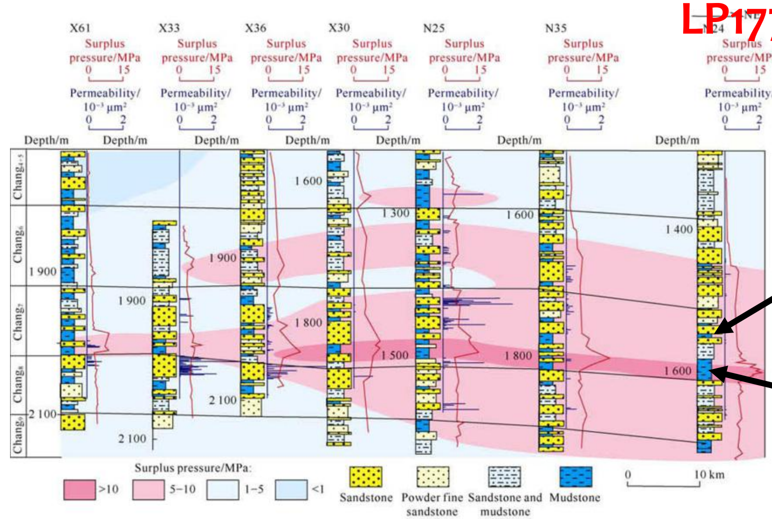
YAO Jingli et al., 2013



Tight SS oil

Shale oil (potential)

Emerging Shale gas -SE Ordos(e.g. LP177 well)

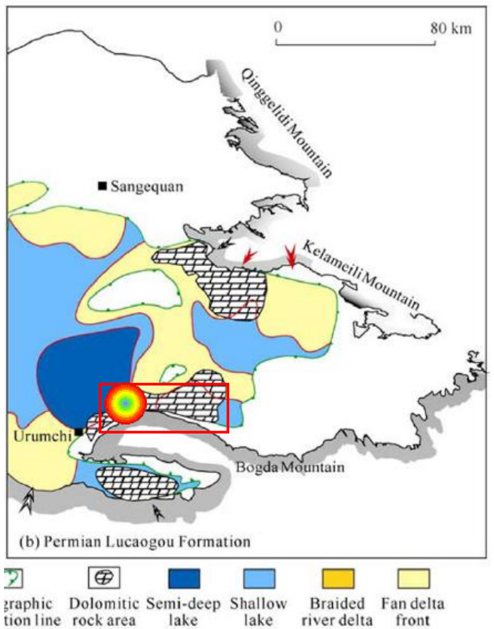


Tight SS oil

Shale oil (potential)

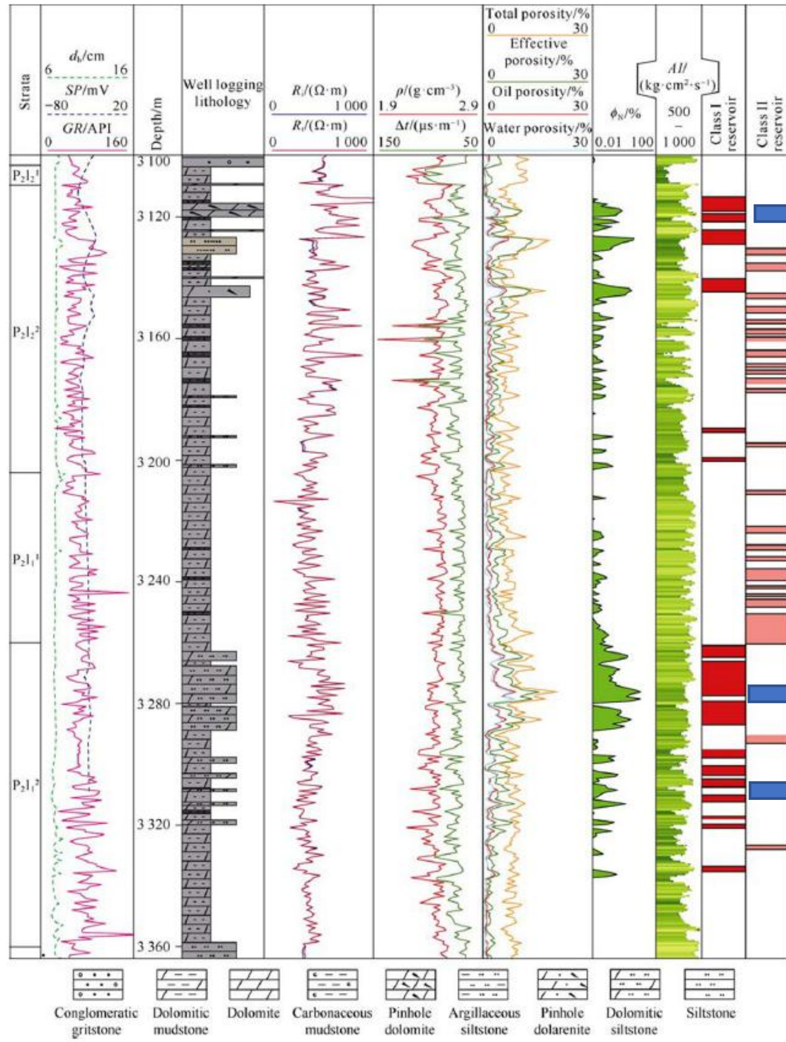
More permeable in SS interval

Hybrid Plays in Permian Lacustrine SR Interval in Junggar Basin, NW China



Permian Lucaogou shale and tight oil

KUANG Lichun, et al., 2012



Comprehensive well logging evaluation chart of the Lucaogou Formation reservoir in the Jimsar Sag. d_h—hole diameter; ntaneous 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.

Tight dolomite oil

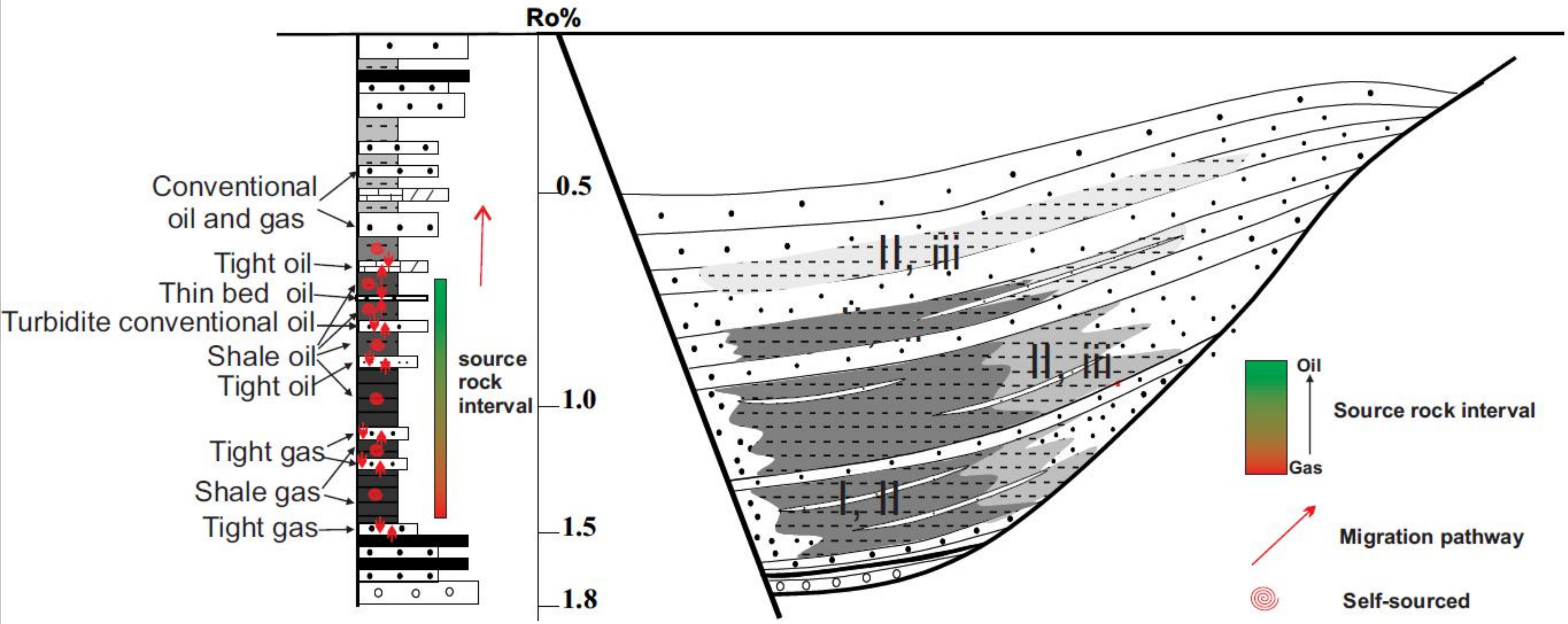
Shale oil

Shale oil

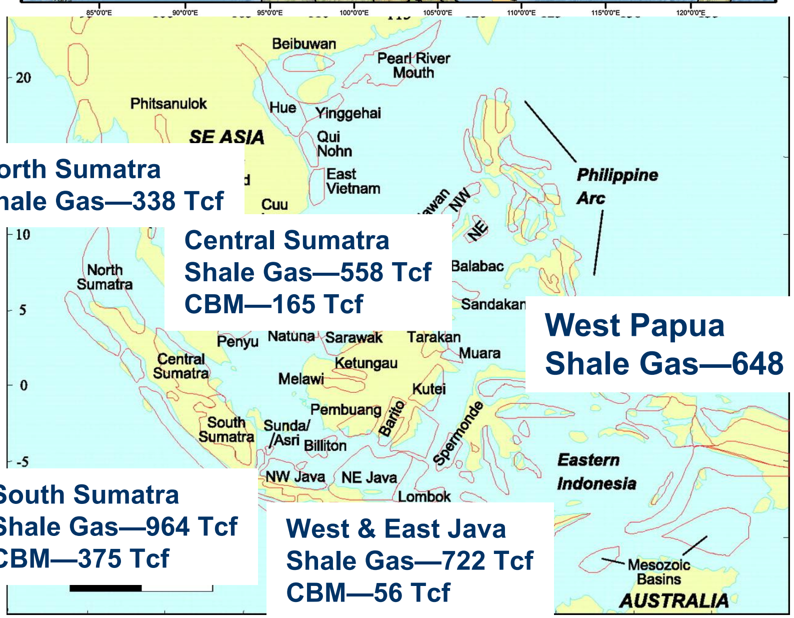
Tight dolomite oil

Tight dolomite oil

Hybrid Plays Model for Lacustrine Source Rock Interval



Continental Basins in China and ASEAN Countries



North Sumatra
Shale Gas—338 Tcf

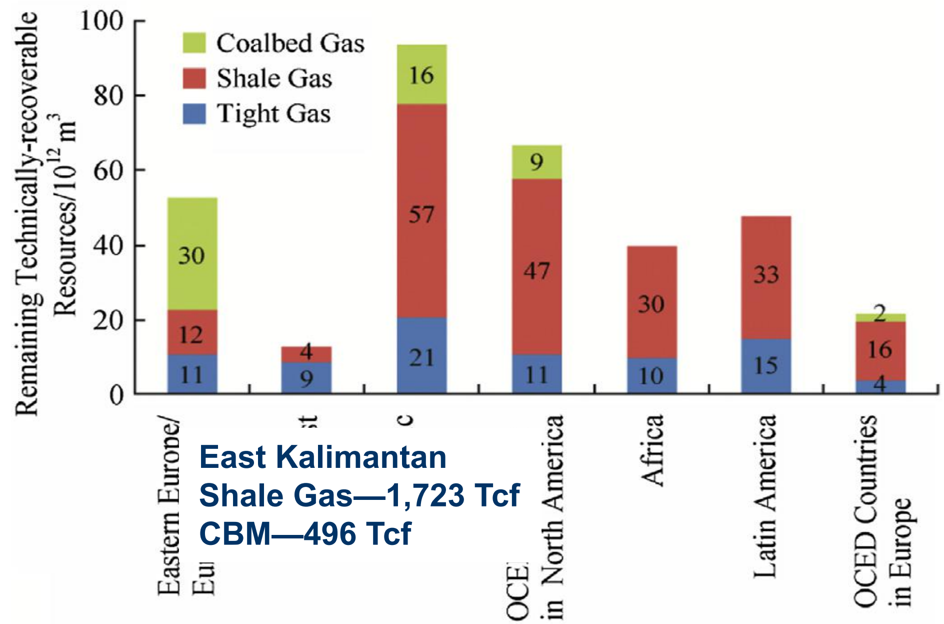
Central Sumatra
Shale Gas—558 Tcf
CBM—165 Tcf

West Papua
Shale Gas—648 Tcf

South Sumatra
Shale Gas—964 Tcf
CBM—375 Tcf

West & East Java
Shale Gas—722 Tcf
CBM—56 Tcf

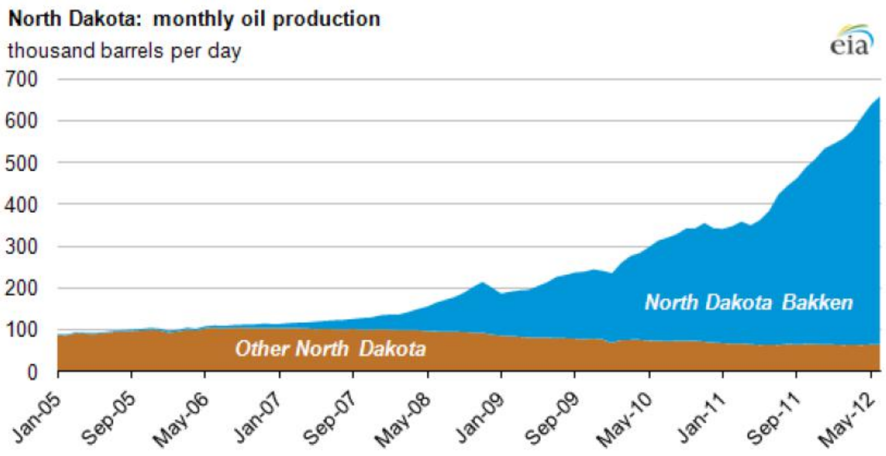
Data from Talisman, 2012

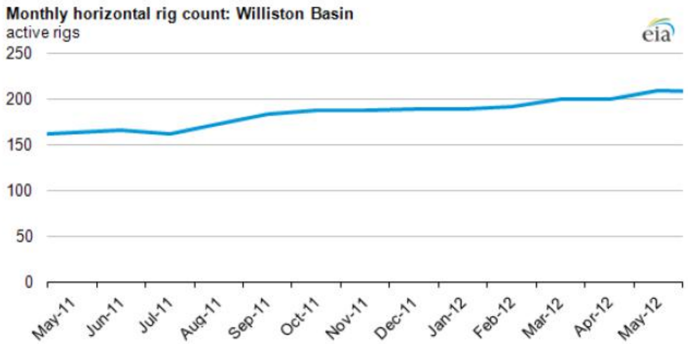


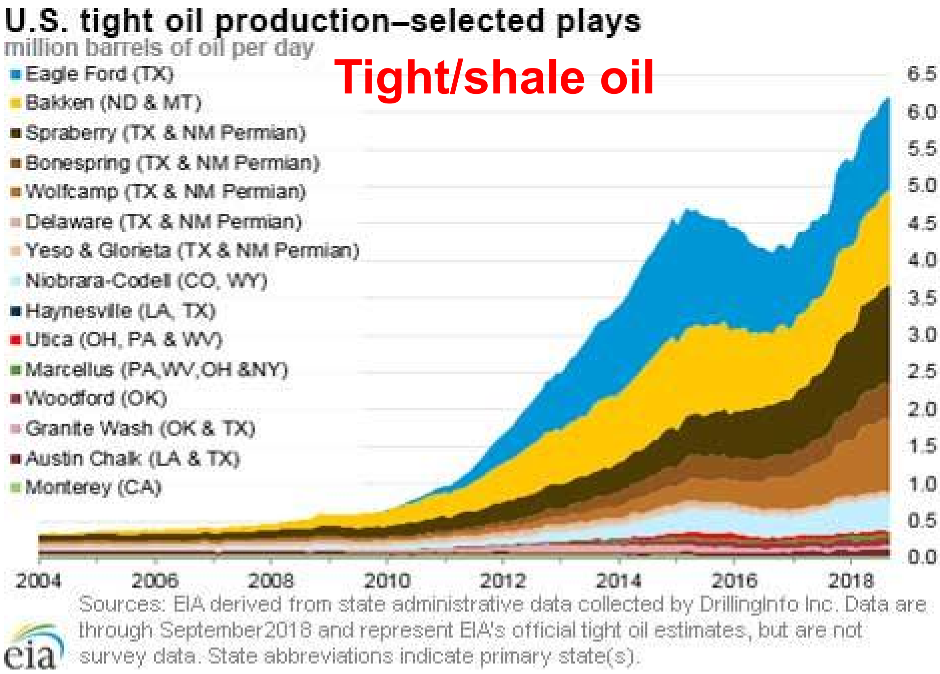
East Kalimantan
Shale Gas—1,723 Tcf
CBM—496 Tcf

Huge hybrid play potentials (shale oil and gas, tight oil and gas, sand and CBM) in continental basins

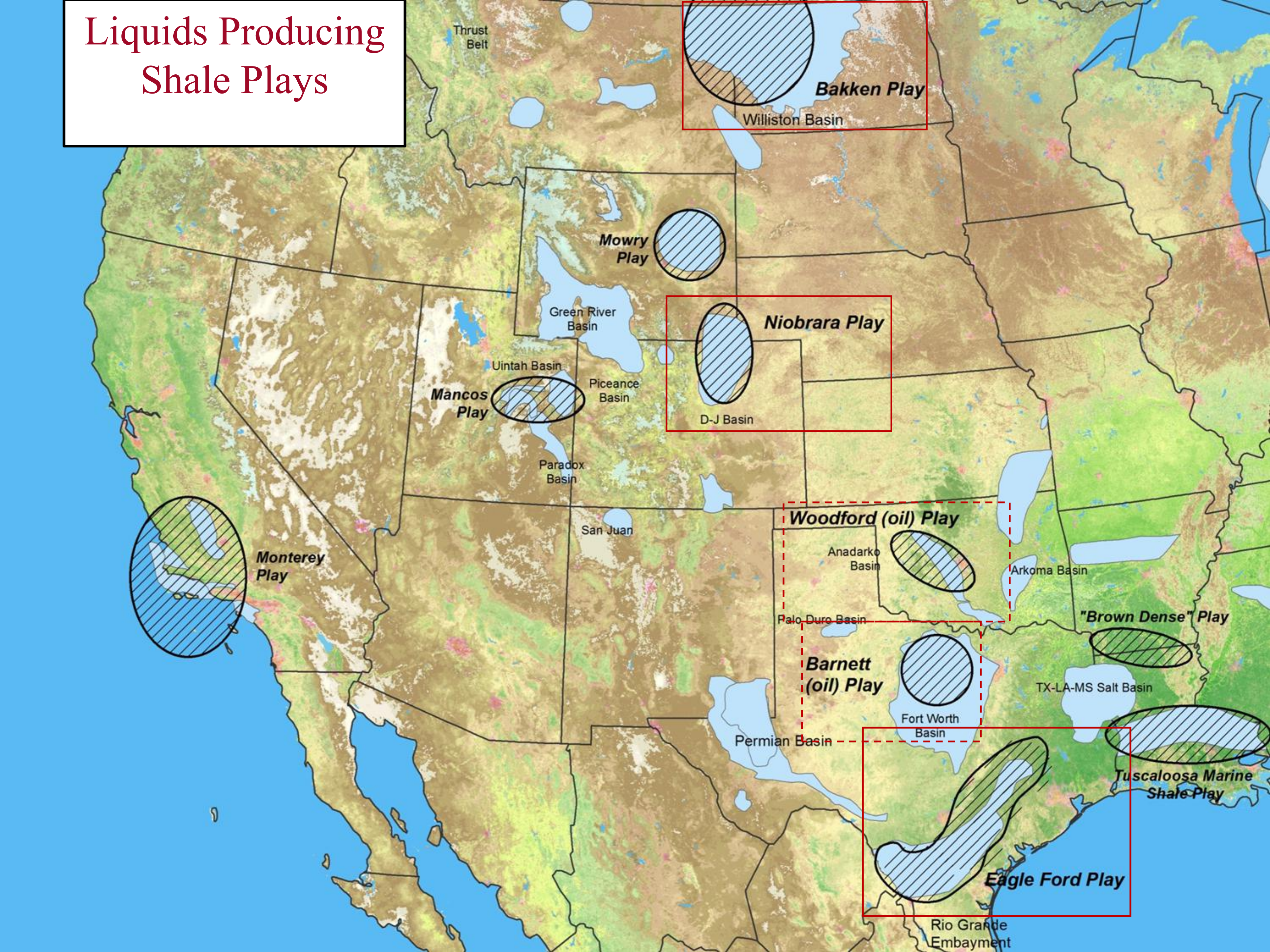
Tight/Shale Oil Evolving Fast Recently



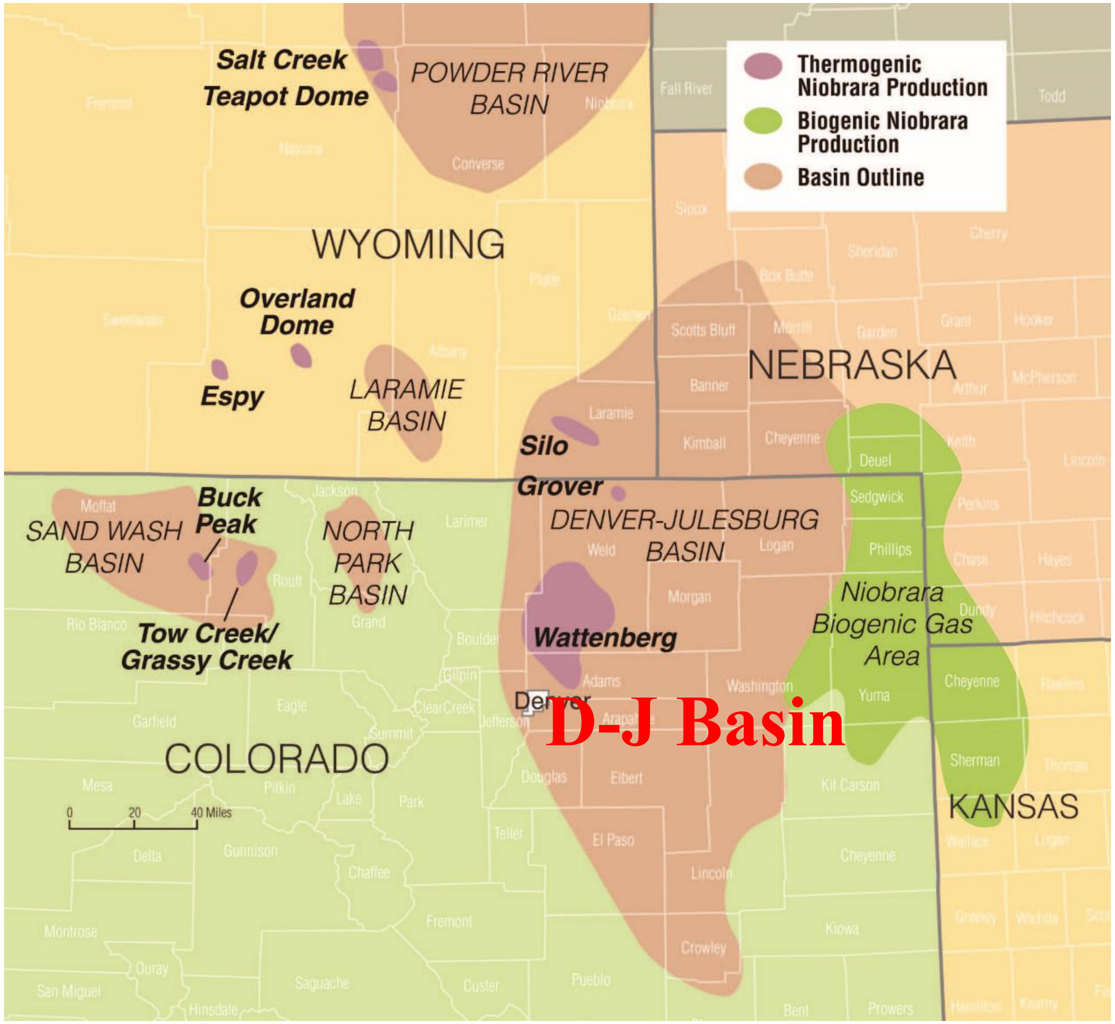


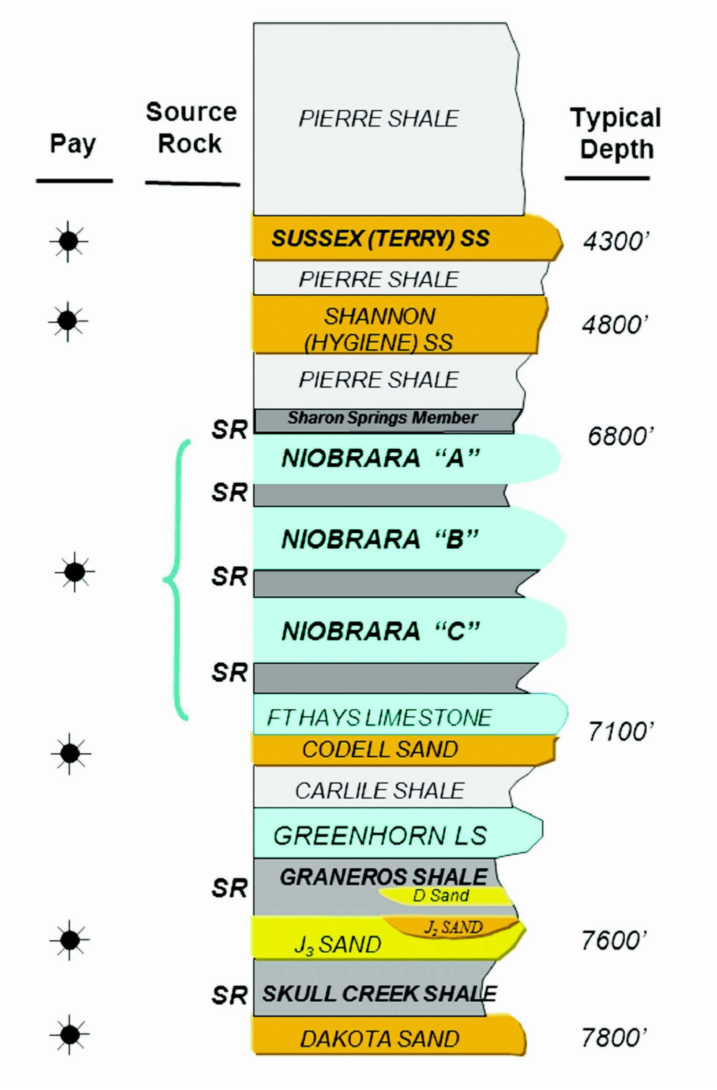


Liquids Producing Shale Plays

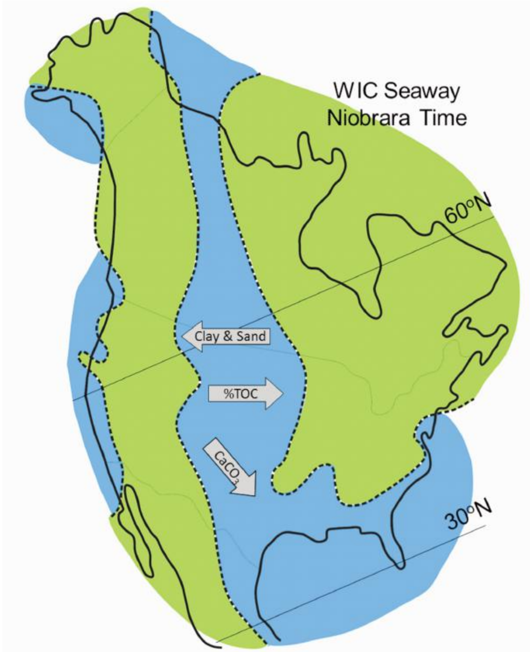


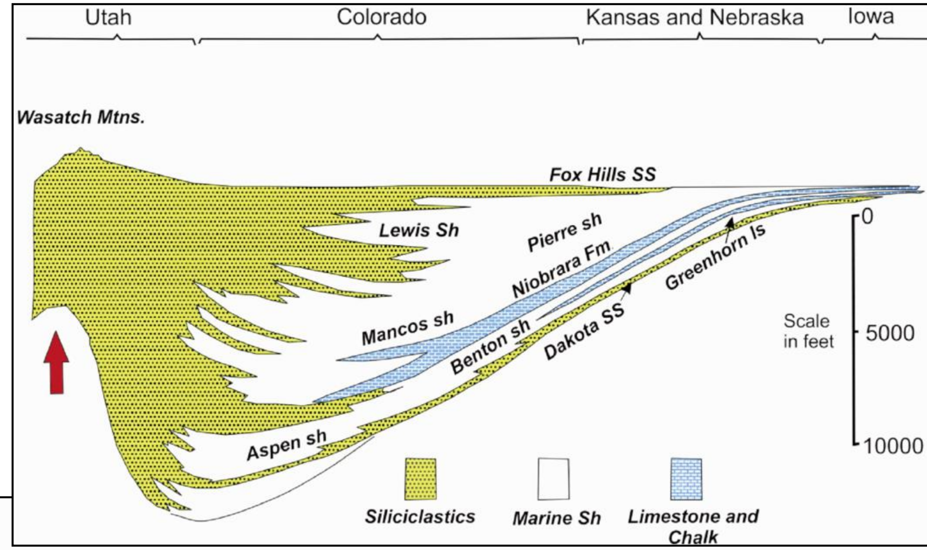
D-J Basin-Niobrara Producing Areas



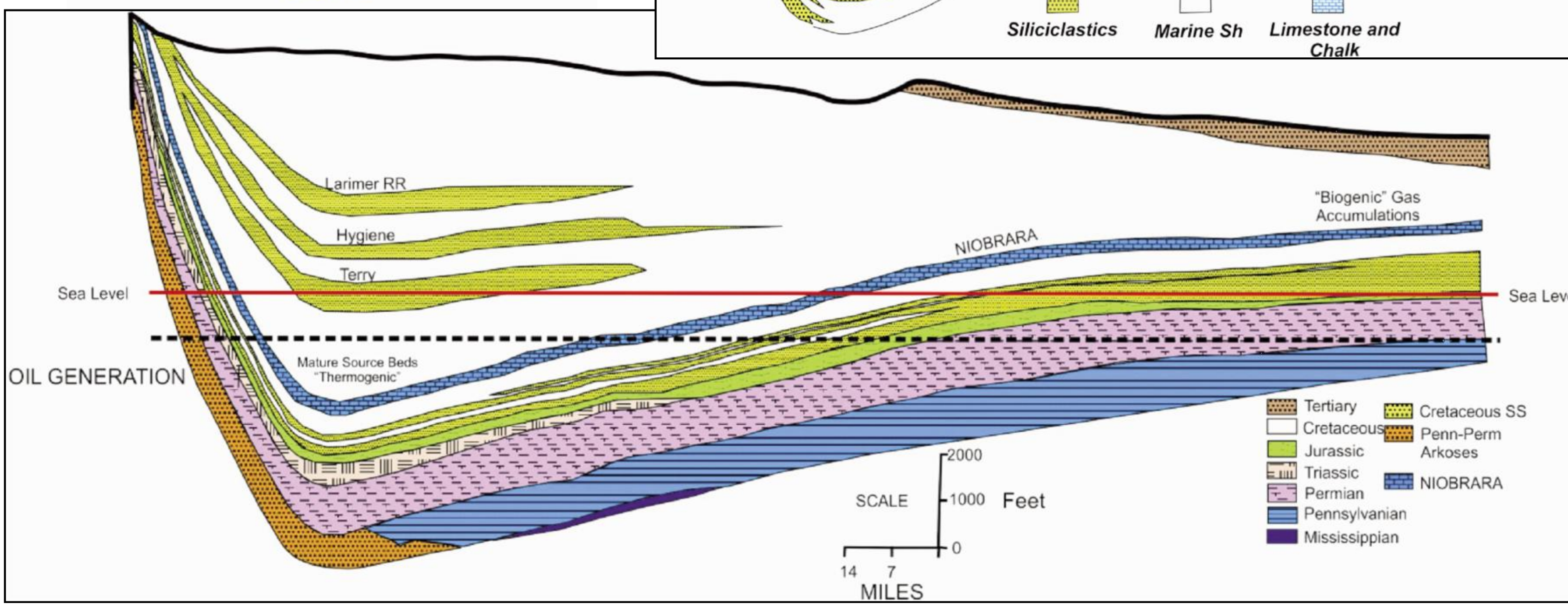


Niobrara Setting





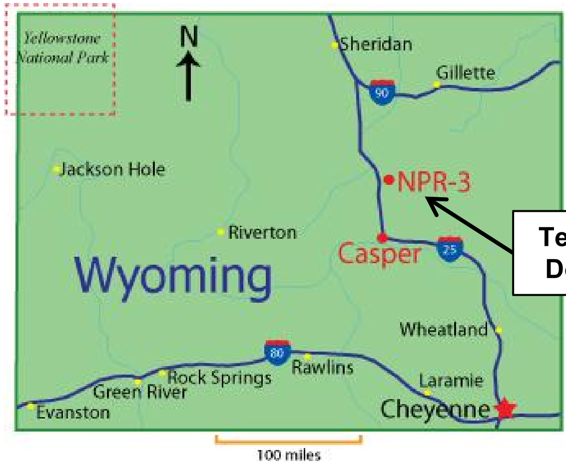
Generalized cross section across the Western Interior Cretaceous Basin. Limestone and chalk beds are present over the eastern two-thirds of the basin.



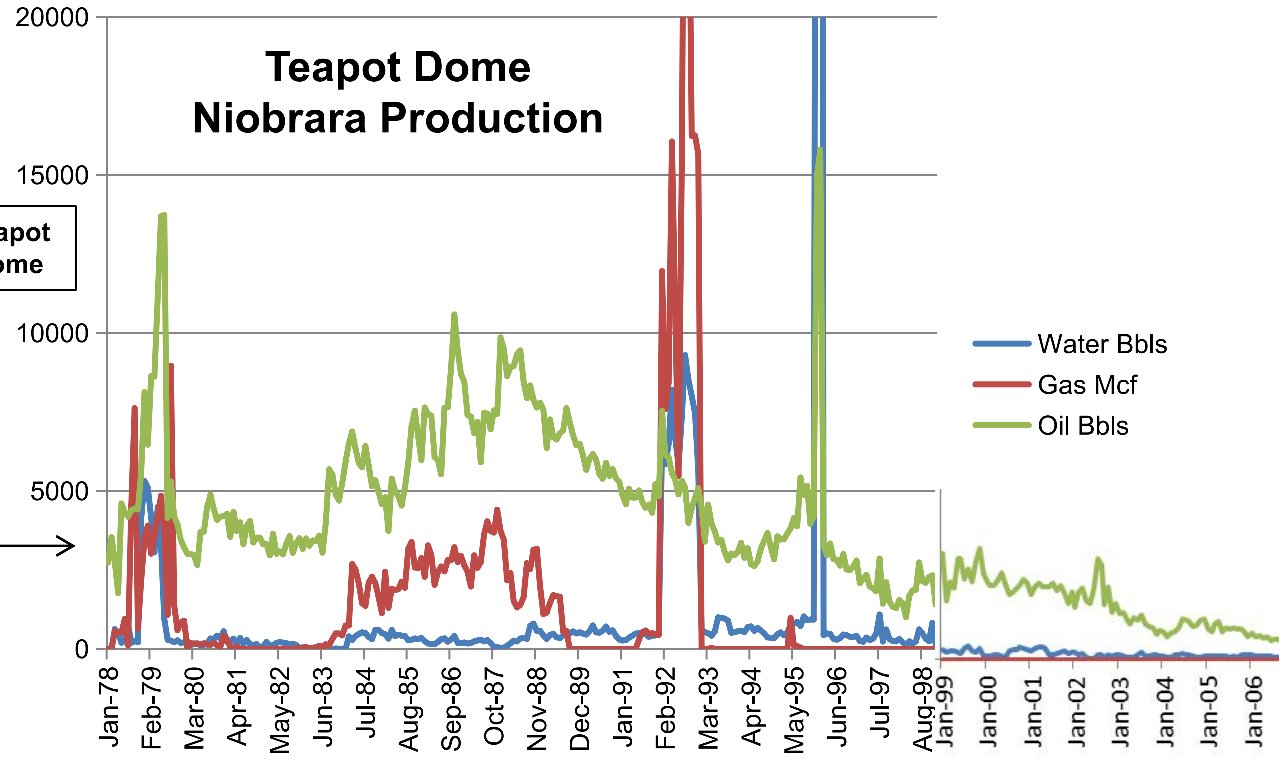
West to east diagrammatic cross section for Denver Basin. Shallow biogenic accumulations in the Niobrara are found on the east flank of basin where source beds are thermally immature for petroleum generation.

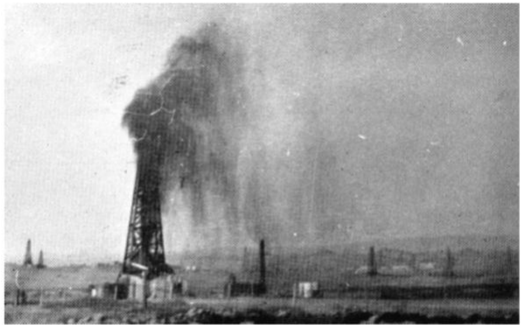
Source: Sonnenberg, Steven, 2011, (after Longman, et al, 1998, and Kauffman, 1977), The Niobrara Petroleum System: A New Resource Play in the Rocky Mountain Region; in Estes-Jackson , Jane E. and Anderson, Donna S., eds., 2011, Revisiting and revitalizing the Niobrara in the Central Rockies: Rocky Mountain Association of Geologists

Historical Niobrara Example: Teapot Dome



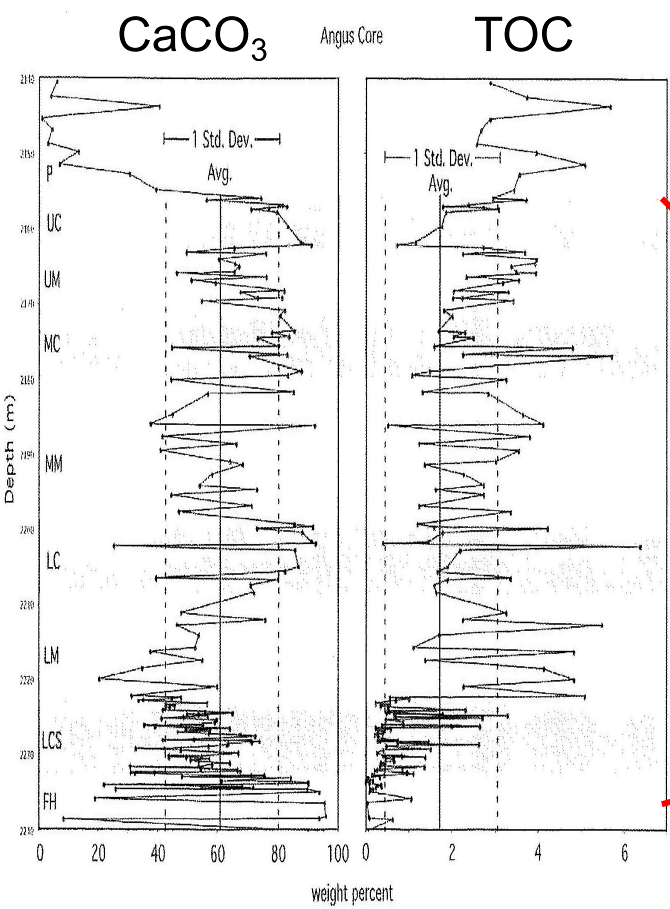
Digital production data is only available since 1978. The actual Niobrara Shale production at Teapot Dome goes back to **1922**, and for example, Well 301 blew out (pictured below), flowing 28,000 BO for six days.

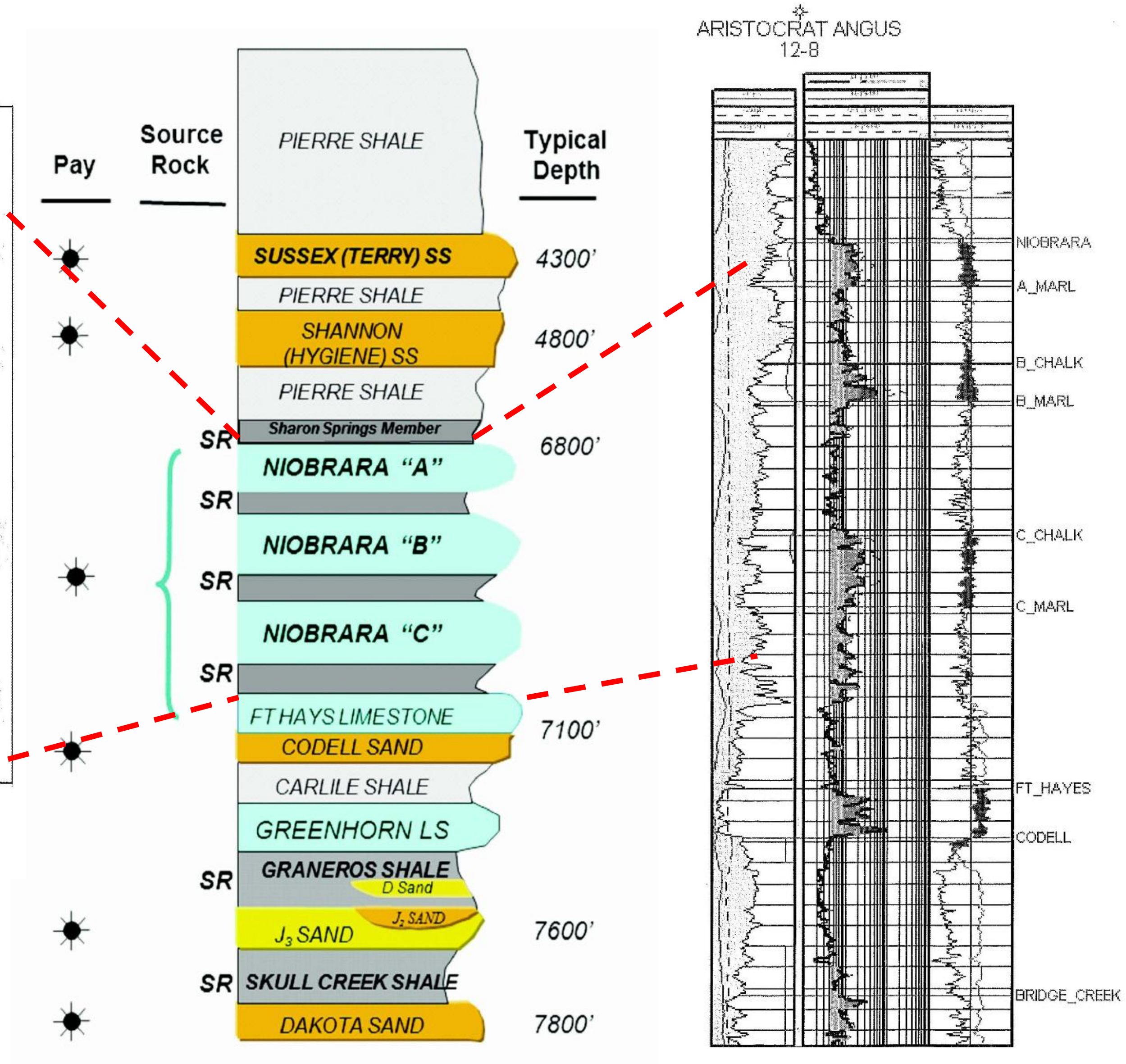




The spikes in the oil production are due to individual wells coming on-line, with large "flush production" from natural fractures, and rapid declines as the fractures close. These Teapot Dome wells are all vertical wells, with no frac jobs, and mainly fall-back completions when another deeper target zone was disappointing, but shows were seen when drilling through the shales.

Niobrara Facies

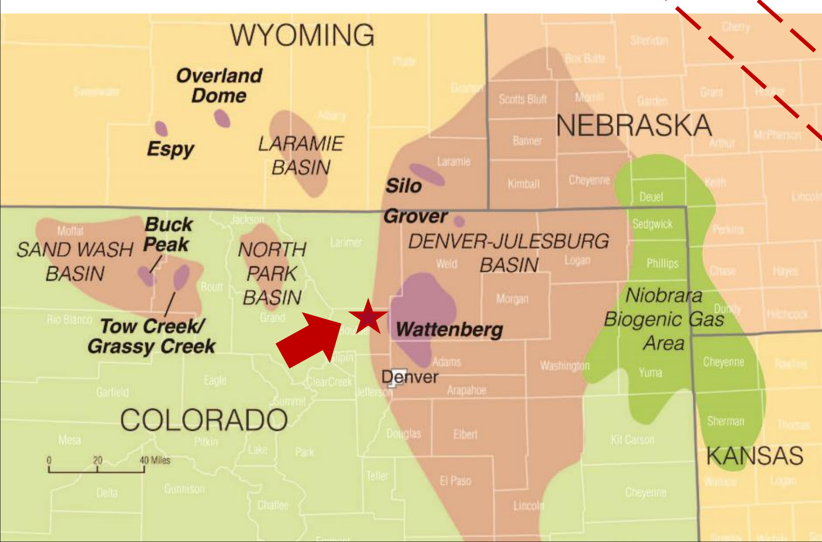


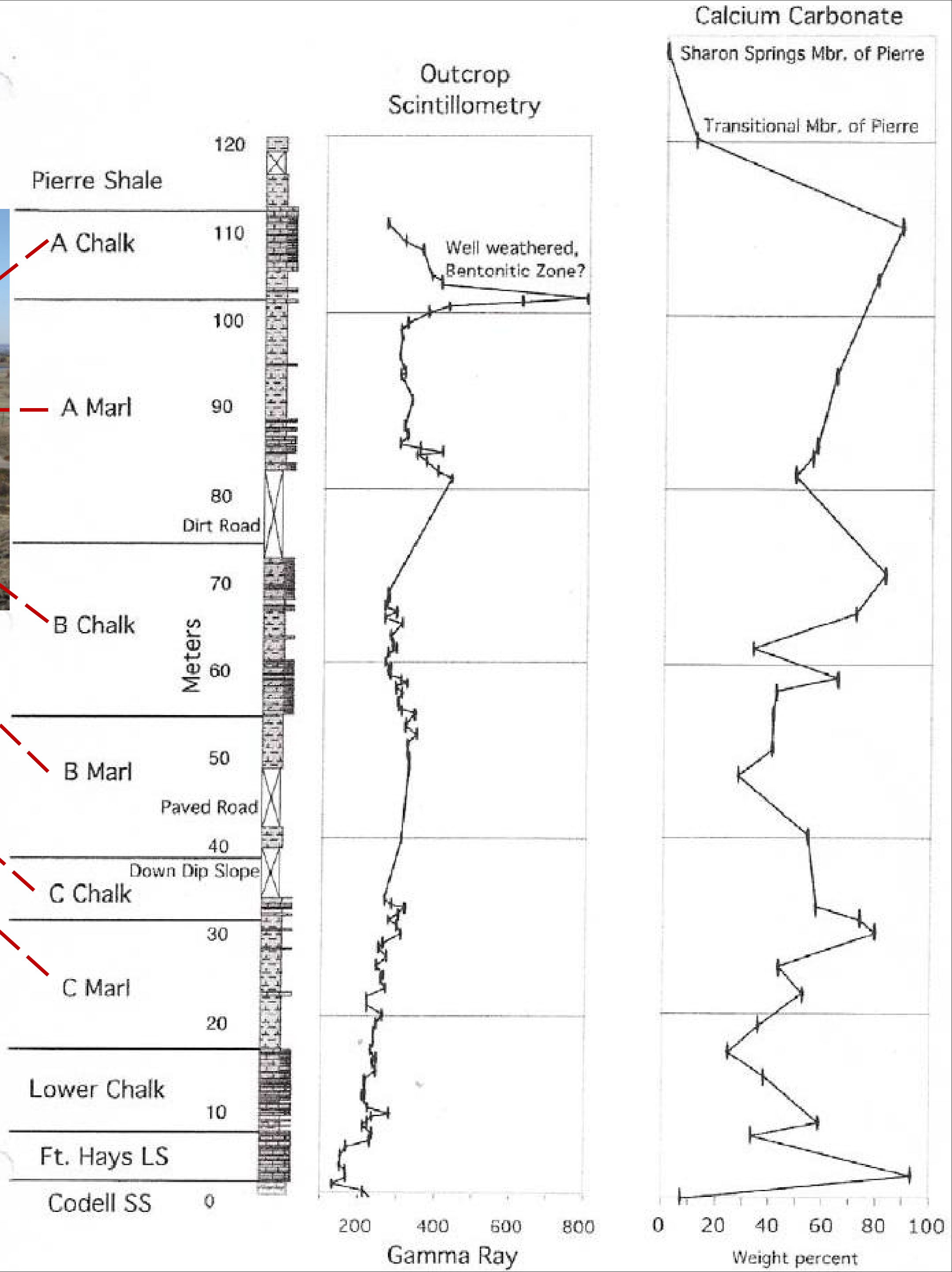


Source: Sonnenberg, Steve, 2011, The Niobrara Petroleum System: A New Resource Play in the Rocky Mountain Region in Estes-Jackson , Jane E. and Anderson, Donna S., eds., 2011, Revisiting and revitalizing the Niobrara in the Central Rockies: Rocky Mountain Association of Geologists

Six Mile Fold ★

Gustason, G., and M. Deacon, 2010, Niobrara Stratigraphy & Shale Resource, DJ Basin: PTTC Field Trip Guidebook, 104 pg.

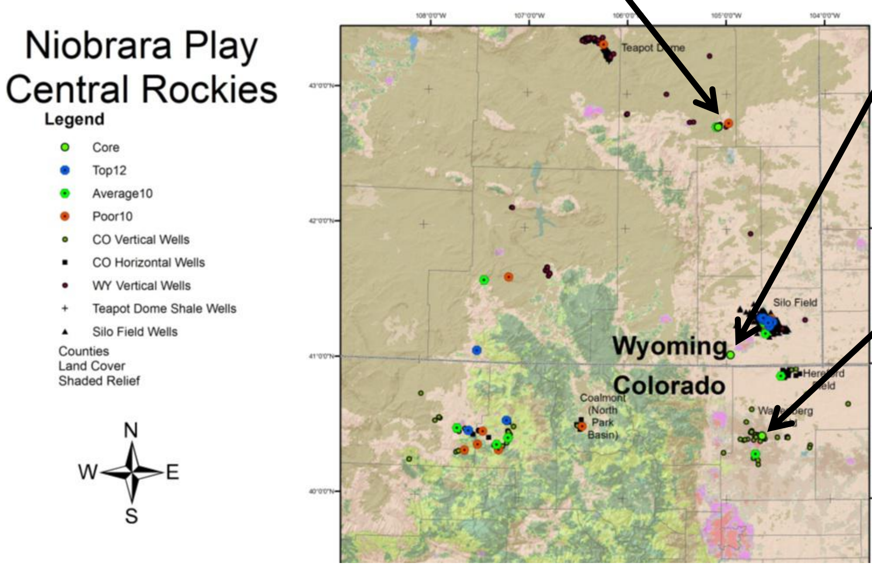


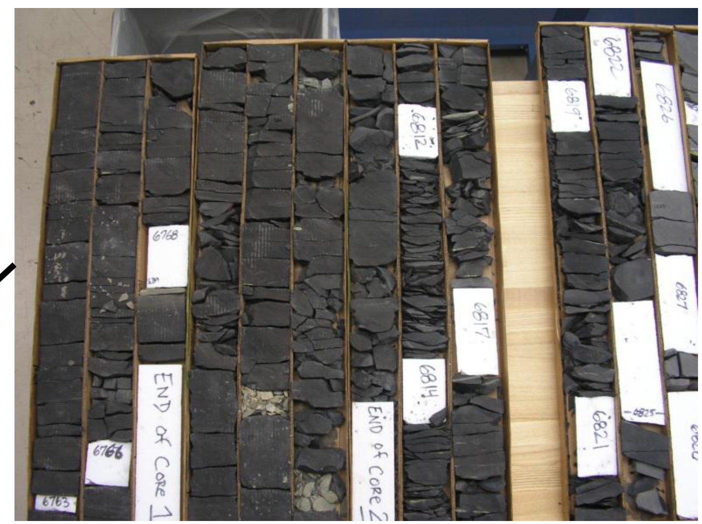


Selected core examination Niobrara

Inexco 1-12 J T Federa
Sec 12-T32N-R69W
Converse Co. WY

Bass 25-12 Belvoir
Sec 25-T13N-R68W
Laramie Co. WY



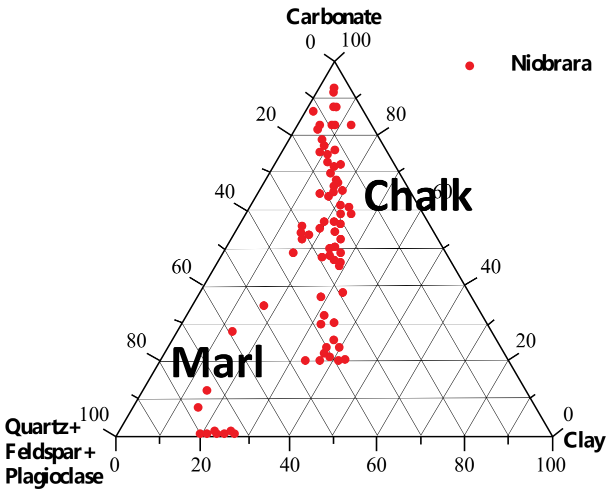


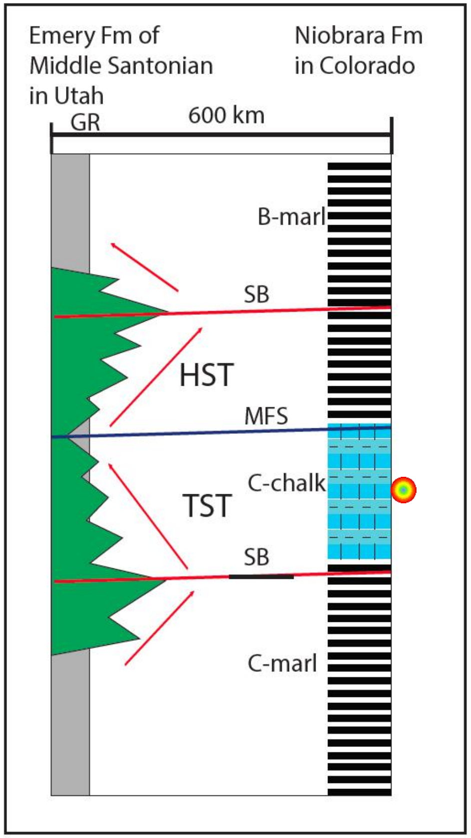
Coors 42-21 Bickling
Sec 21-T6N-R65W
Weld Co. CO

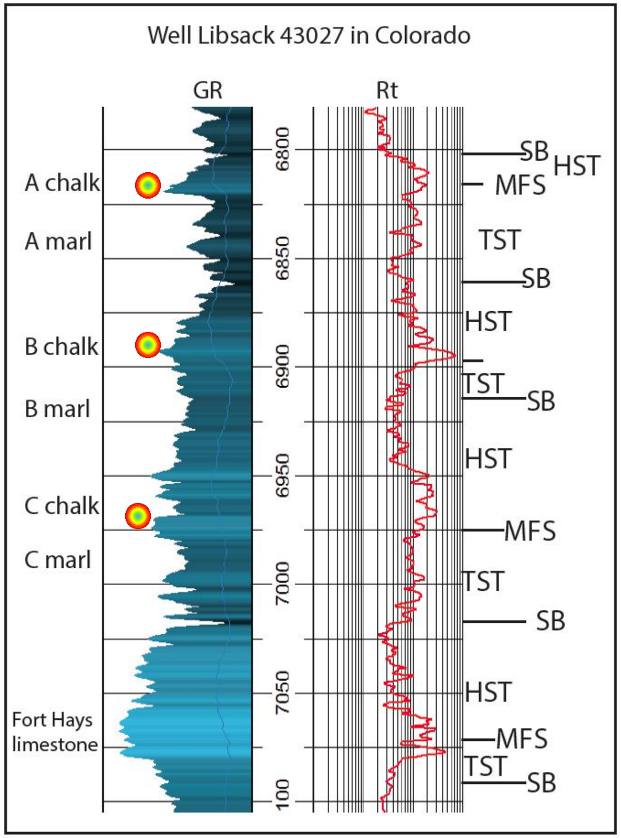
Niobrara Carbonate –rich Shale in U.S.

Niobrara chalk

Niobrara marl







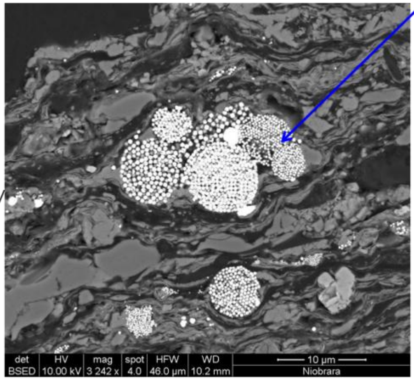
Best reservoir-MFS Low GR, high R, low quartz, high carbonate

Poor reservoir- early TEST and late HST, High GR, low R, high quartz and clay

QEMScan and SEM Analysis

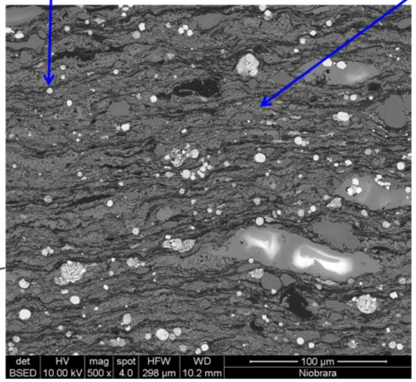
Well: Burbach 20-3H
Depth: 7185.3’
Hereford Field, CO

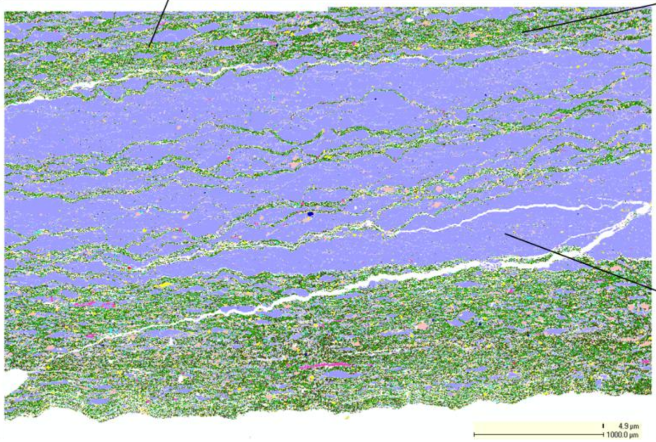
Mineral Name	Area %
Calcite	44.81
Micrite	13.83
Illite	13.08
Background	7.36
Particle Rims	6.20
Other Silicates	5.76
Other	5.21
Quartz	4.56
Plagioclase	2.74
Pyrite	2.59
Apatite	0.68
Glauconite	0.30
Dolomite	0.12
Biotite	0.11
Smectites	0.01
Rutile	0.01
Muscovite	0.00
Chlorite	0.00
Barite	0.00
Alkali Feldspar	0.00
Zircon	0.00
Fe-oxides	0.00



Pyrite framboids

Clay minerals

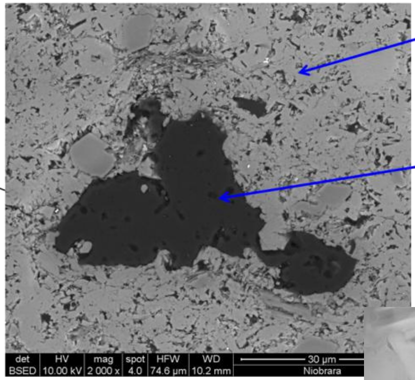


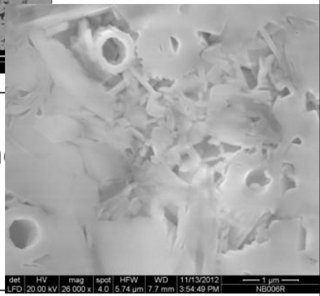


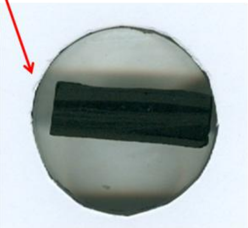
5µm Resolution

Calcite matrix

Organic matter porosity (dark spots) inside kerogen





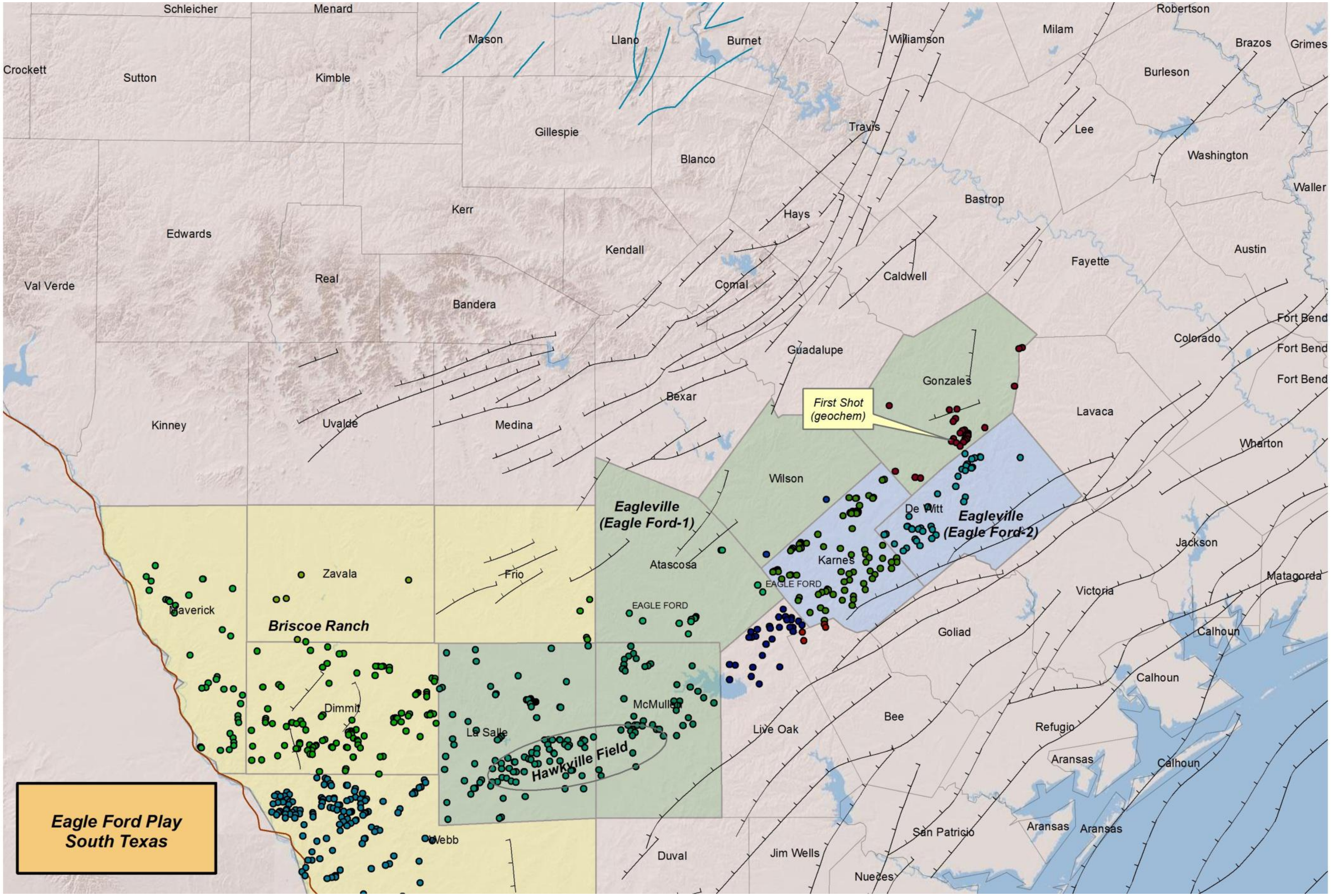


Core sample from 7185.3 ft

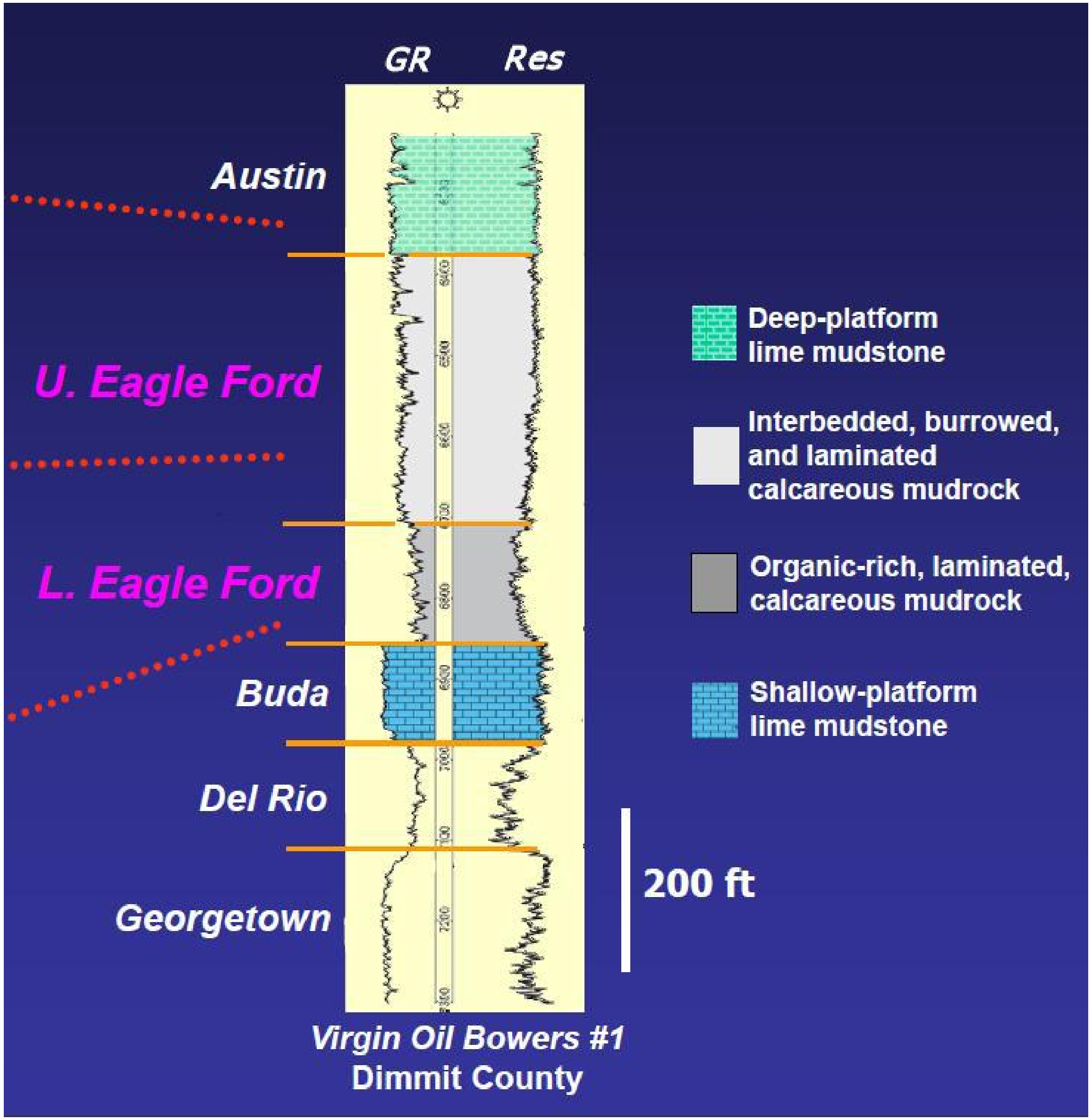
Figure _ QUEMSCAN image from the Burbach 20-3H well at 7185.3’ depth. Interbedded marl and chalkier layers with an anastomosing pattern of both fractures and marl lamina… Note how the open horizontal fracture intersects both chalk and the more ductile marl layer.

SEM images from the same Burbach 20-3H well sample at 7185.3’ depth.

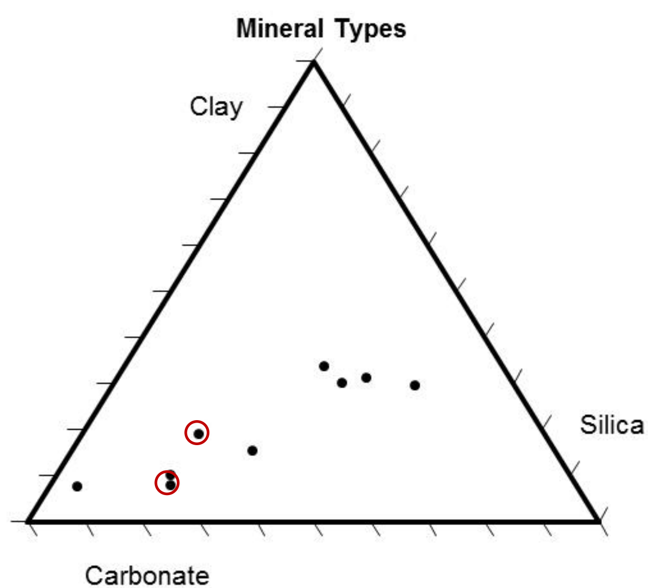
Eagle Ford Base Map



Eagle Ford Shale



Hentz and Ruppel, 2011, TX BEG (AAPG)



Eagle Ford Outcrop

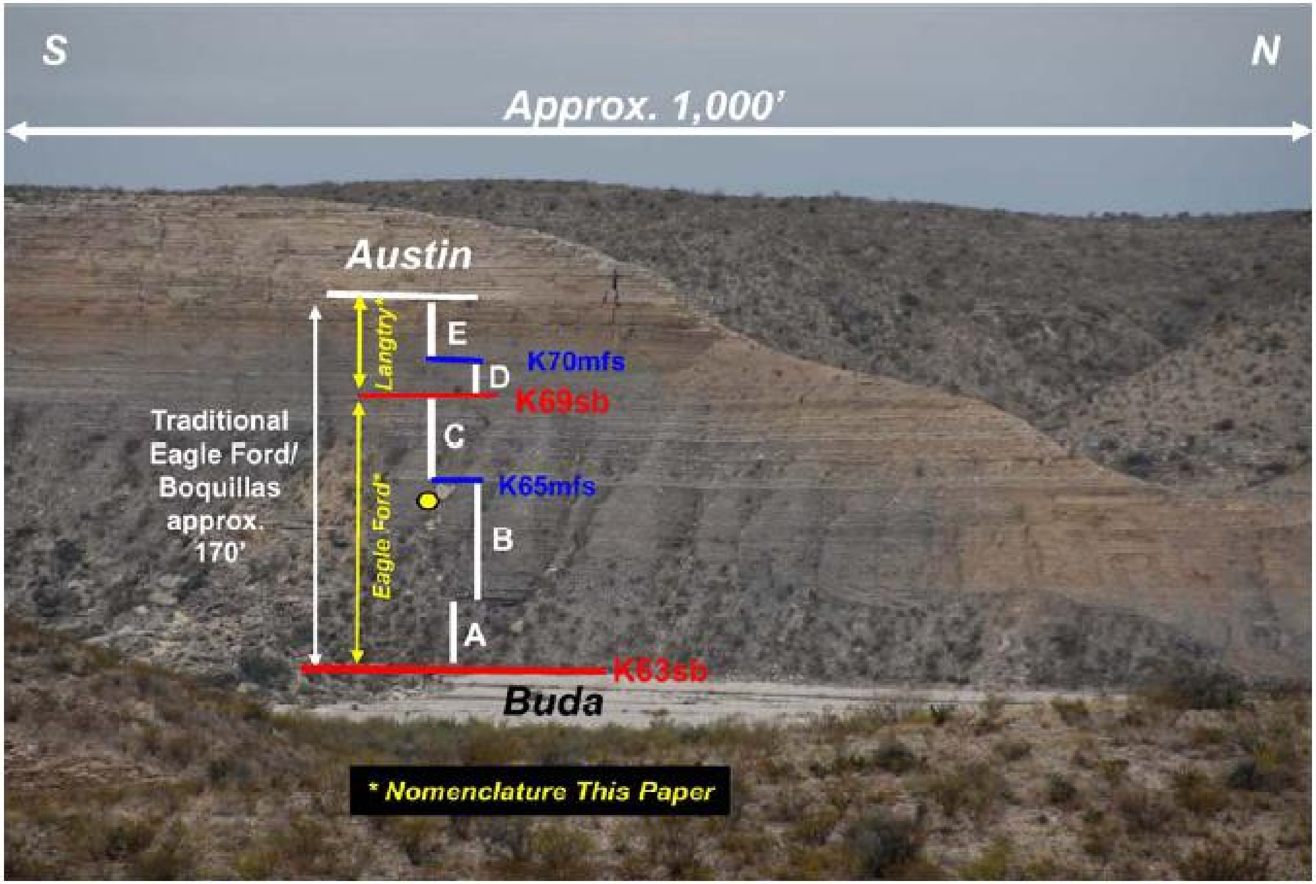
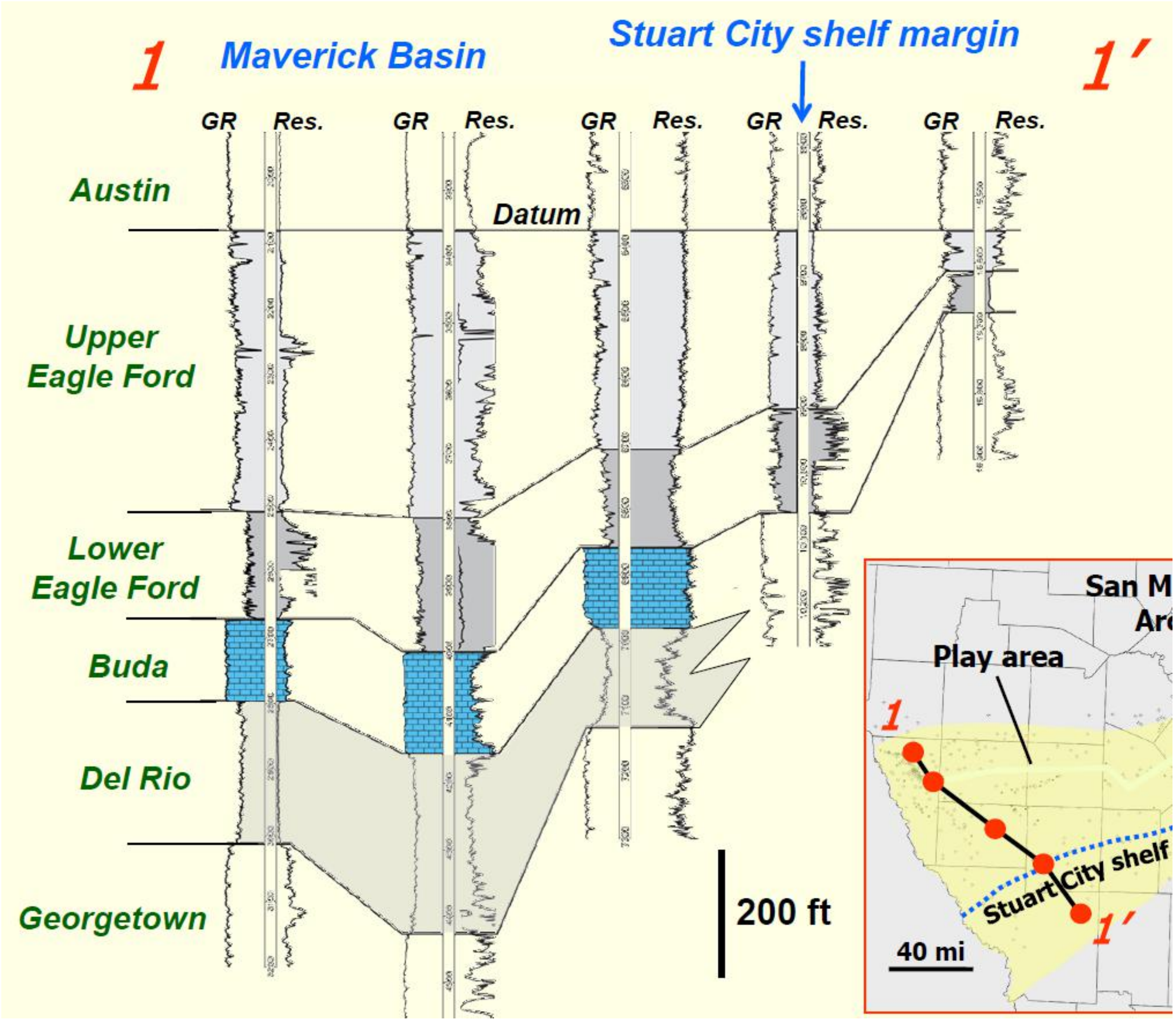


Figure 3. Digital image of the Lozier Canyon outcrop showing exposures of the Buda, traditional Eagle Ford (Boquillas), and Austin formations. Lozier Canyon, is located in Terrell County, Texas, just south of U.S. Highway 90. Please note: (1) Eagle Ford (EF) and Langtry (L) as defined in this paper, (2) the position of facies A, B, C, D, and E within this succession, (3) interpreted position of K63sb, K65sb, K69sb, and K70mfs stratal surfaces, and (4) location of a latest Cenomanian age interpretation from preliminary biostratigraphic analysis is shown as a yellow dot. Note that facies B contains organic-rich calcareous mudstones similar to those exploited in the subsurface of South Texas.

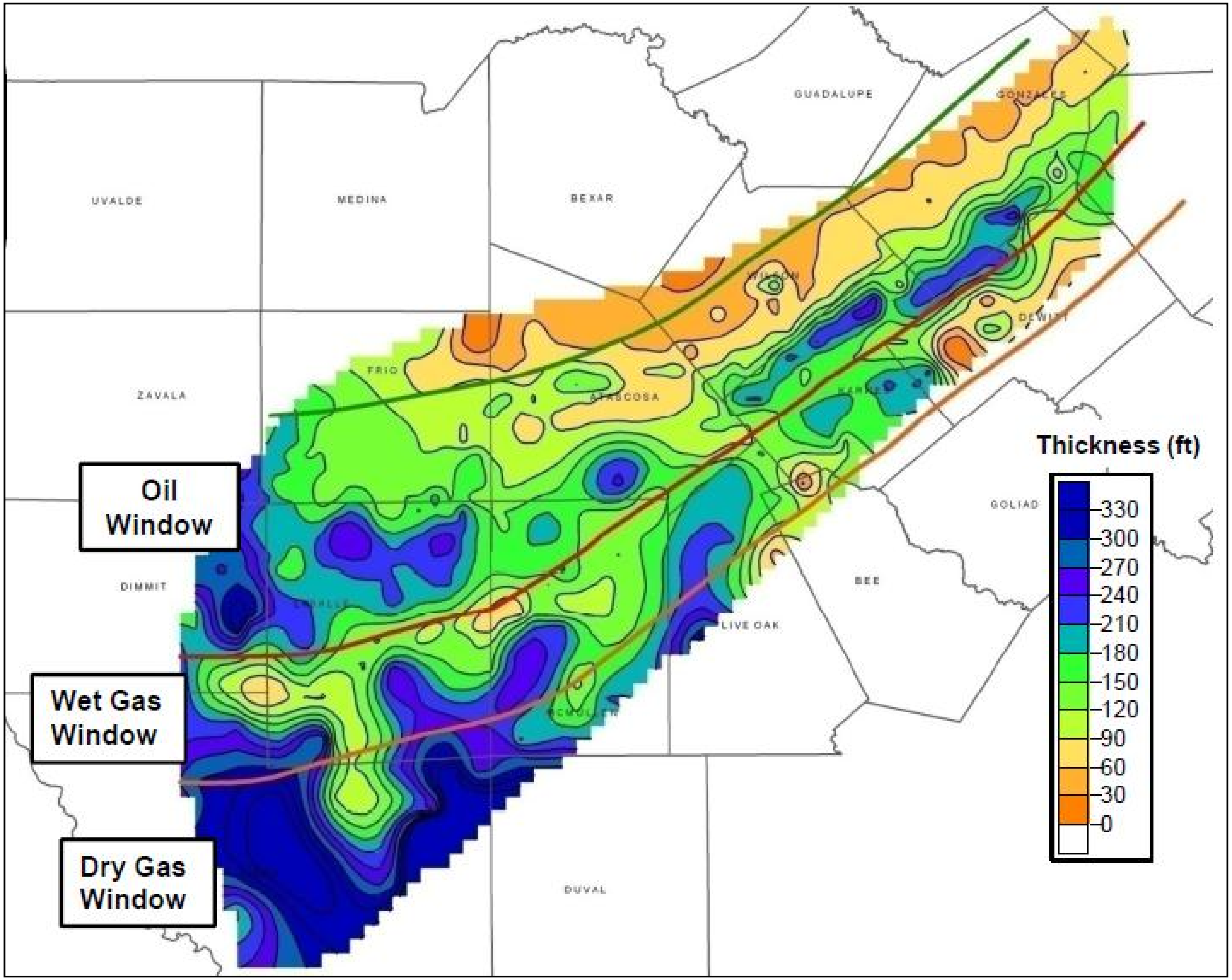
Source: Donovan, A. D., and T. S. Staerker, 2010, Sequence stratigraphy of the Eagle Ford (Boquillas) Formation in the subsurface of South Texas and outcrops of West Texas: Gulf Coast Association of Geological Societies Transactions, v. 60, p. 861-899.

Eagle Ford Cross Section 1-1’

Source: Hentz and Ruppel, 2011, Regional Stratigraphic and Rock Characteristics of Eagle Ford Shale in Its Play Area: Maverick Basin to East Texas Basin*; S&D Article #10325*Adapted from oral presentation at AAPG Annual Convention and Exhibition, Houston, Texas, USA, April 10-13, 2011



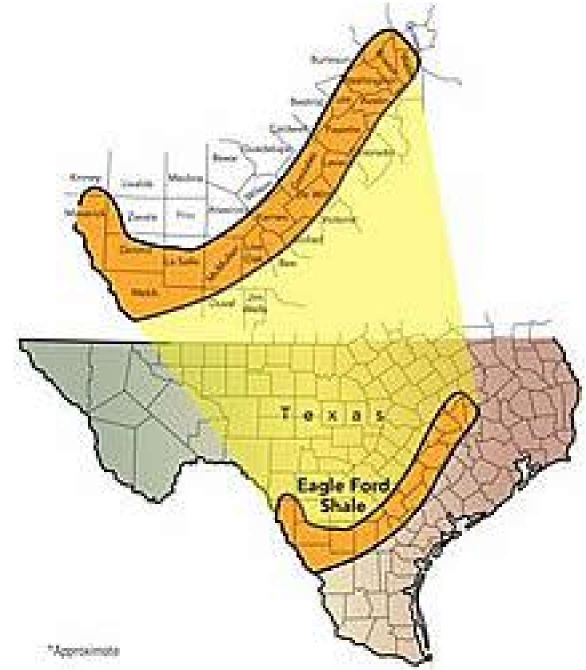
Eagle Ford Isopach Map – EOG



Source: EOG Investor Meeting, Eagle Ford, April 2010; www.eogresources.com

Eagle Ford Shale Characteristics

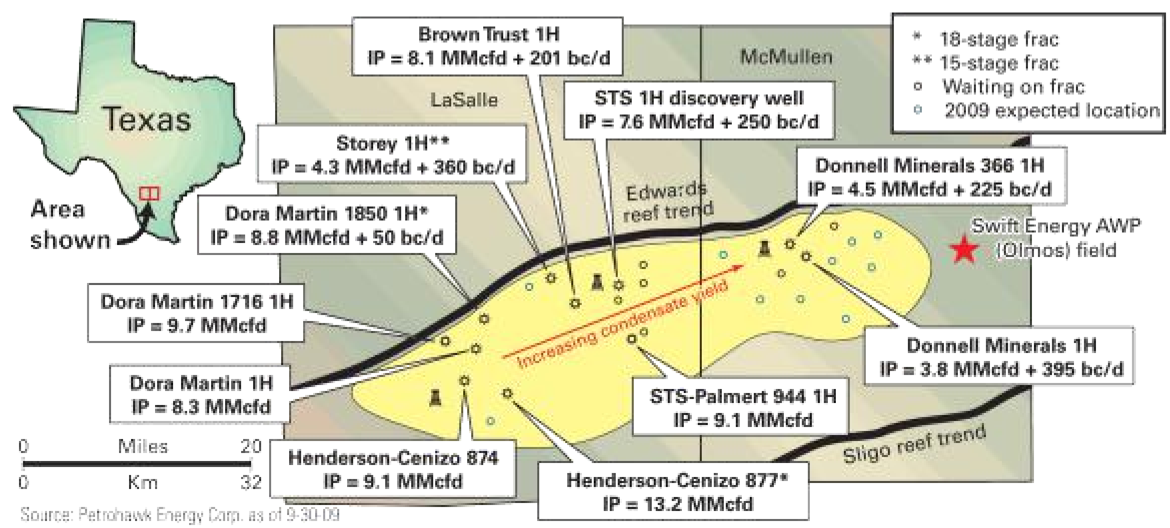
- Basin Area = ~3,800 mi² (~10,000 km2)
- Reported recoverable volumes = **21 Tcf**
- Depth = **4,000 – 12,000 ft**
- Thickness = 100 – 475 ft (30 – 150 m)
- TOC = 3-5%
- Vitrinite Reflectance = 1.0 - 1.27 %Ro
- Porosity = 9-12%
- Permeability = Nanodarcy Range
- Pressure Gradient = 0.43 – 0.70 psi/ft
- Avg. Well IP = **7.0 MMcfd + Cond**
- Cond Ratio ~ **50 Bbl/MMcf**
- First Production ~2008



Oil Wells

- Well IP Range = **400 – 1,800 Bopd**
- API Gravity = **41.5°**

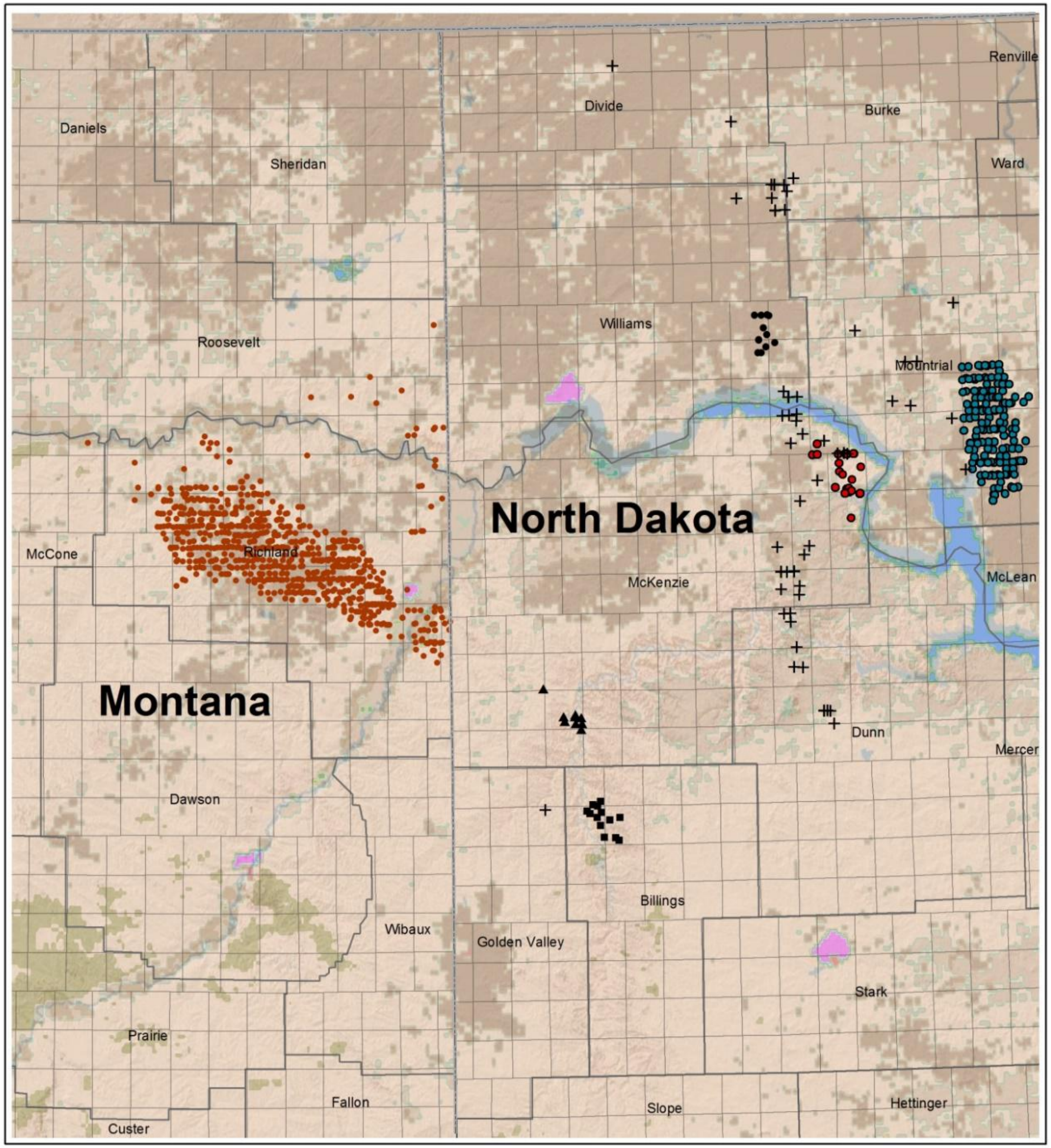
EAGLE FORD SHALE DRILLING RESULTS



Bakken Play

Legend

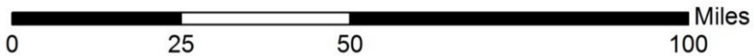
- Elm Coulee Wells
- Beaver Lodge Wells
- Parshall Wells
- Sanish Wells
- Pierre Creek Wells
- Elkhorn Ranch Wells
- Three Forks Wells
- USA Land Survey System



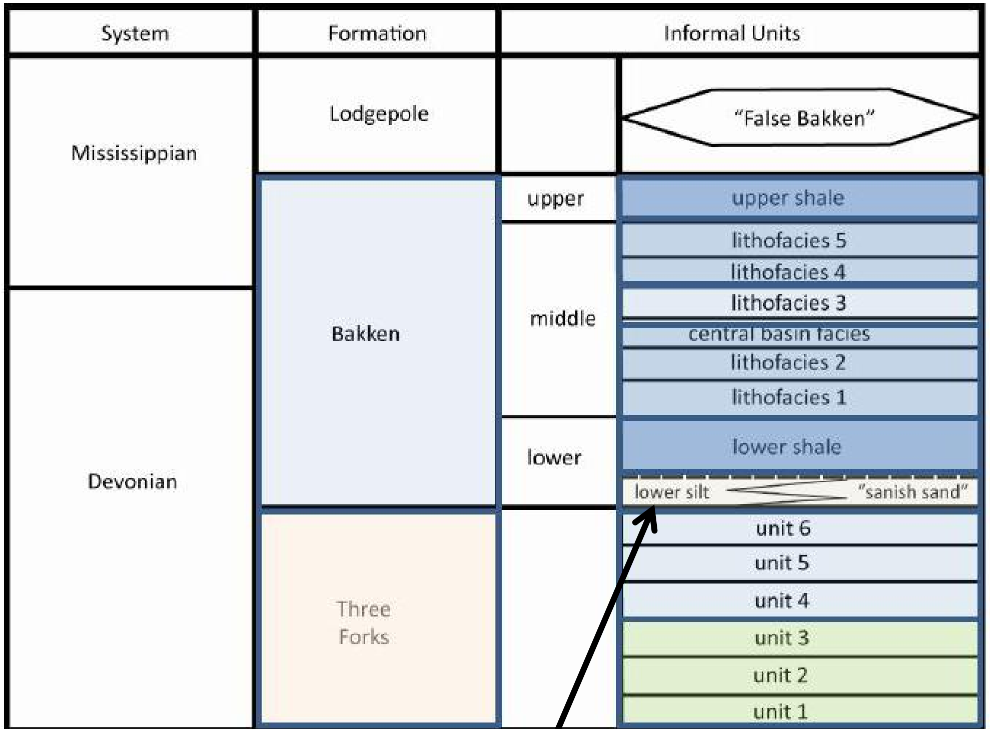
Coordinate System: NAD 1927 UTM Zone 13N
Projection: Transverse Mercator
Datum: North American 1927
False Easting: 500,000.0000
False Northing: 0.0000
Central Meridian: -105.0000
Scale Factor: 0.9996
Latitude Of Origin: 0.0000
Units: Meter

Name: BakkenBasemap1

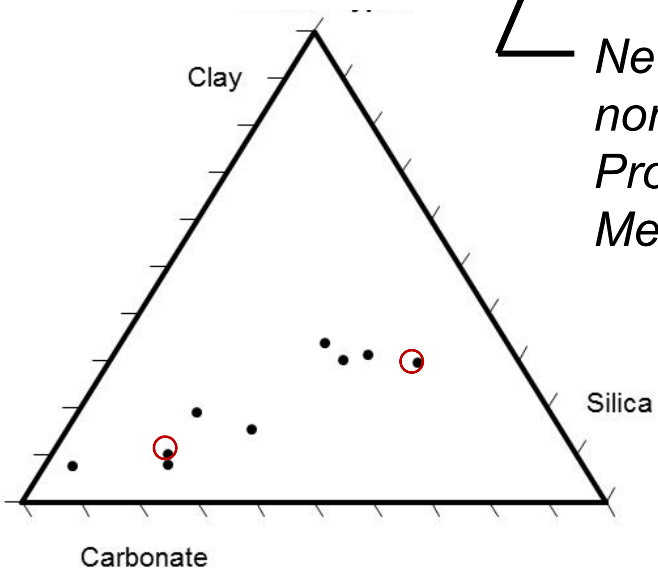
1:1,250,000

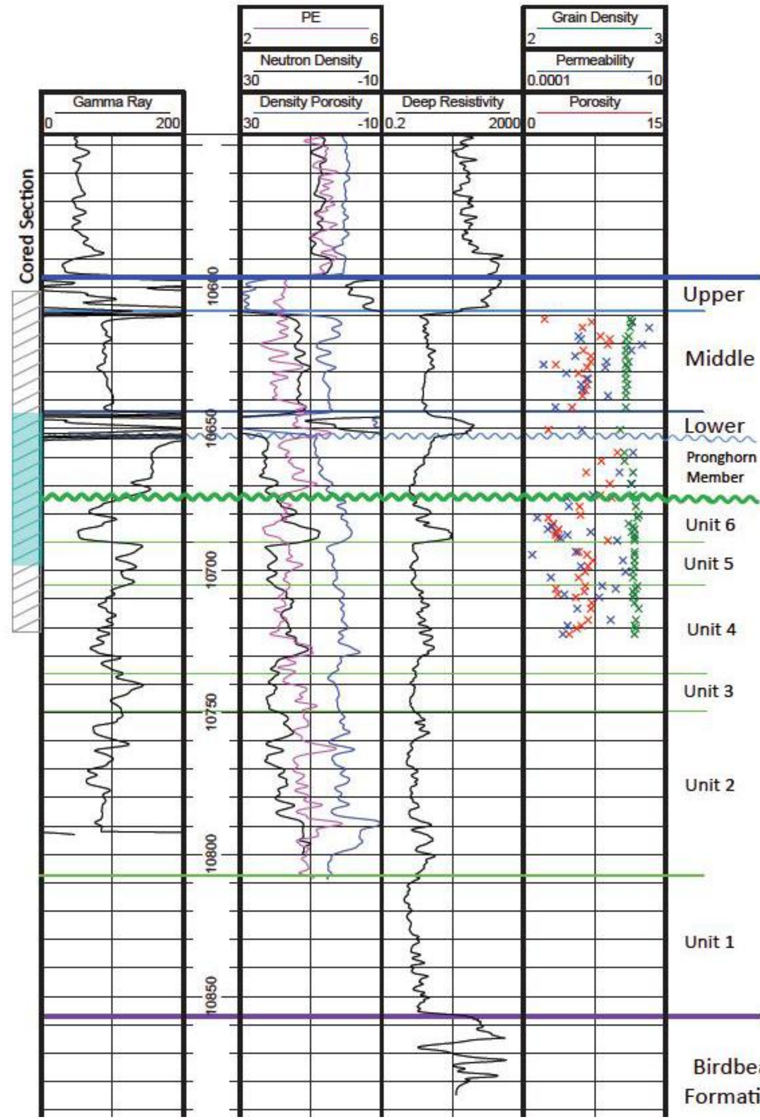


Bakken Fm

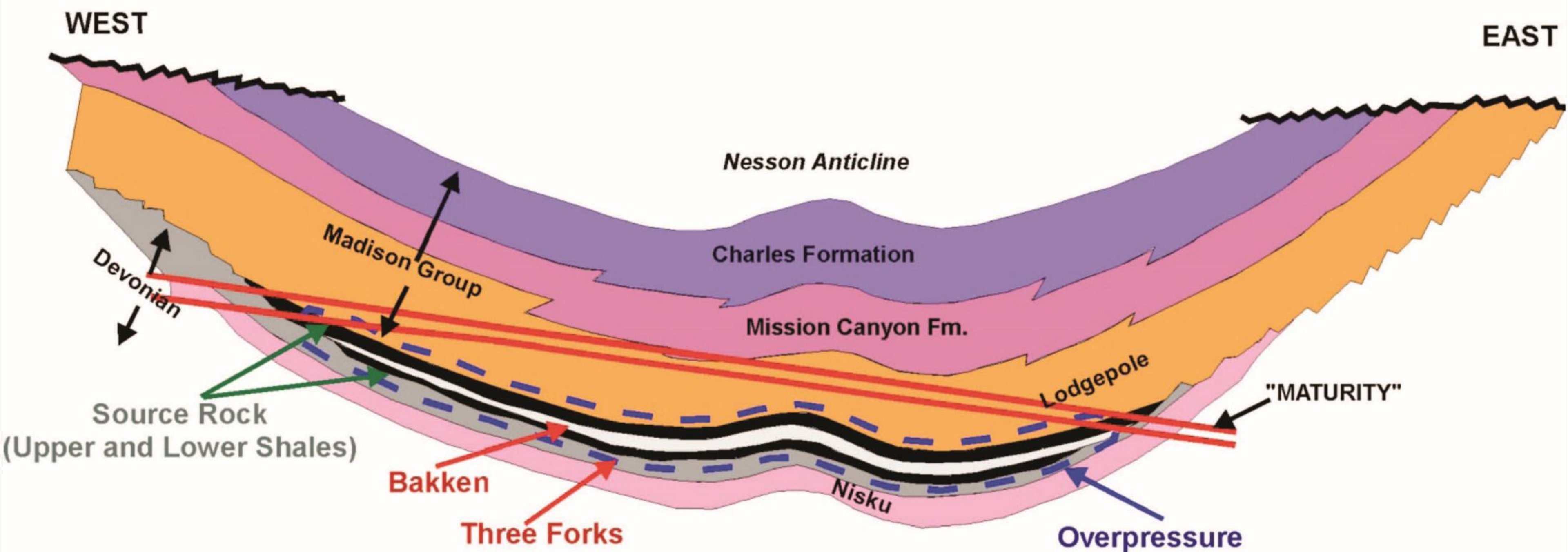


New stratigraphic nomenclature: Pronghorn Member





Bakken Formation



Bakken Pool (per NDIC and NDGS)

- Source
  - Upper and Lower Bakken Shales
- Reservoirs
  - Bakken Shales
  - Clastic carbonate middle member of the Bakken Fm.
  - Three Forks Fm. Upper 50'.
  - Lodgepole (?) Lower 50'

System	Formation	Informal Units
Mississippian	Lodgepole	
	Bakken	upper
Devonian		middle
		lower
	Three Forks	

Bakken Target Zones

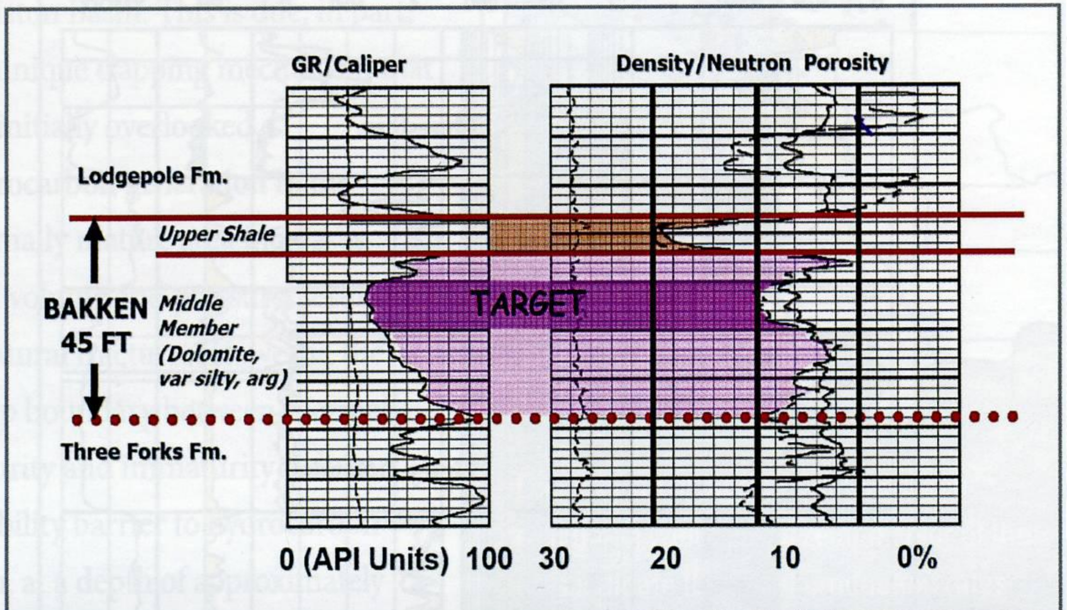


Fig. 17. Elm Coulee field type log. Balcron Oil 44-24 Vaira well, S24-T24N-R54E (Walker et al., 2006).

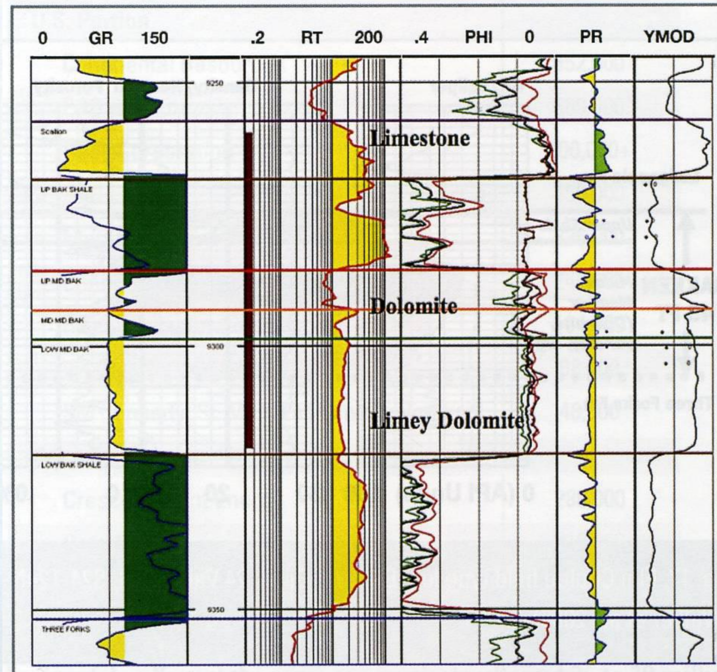
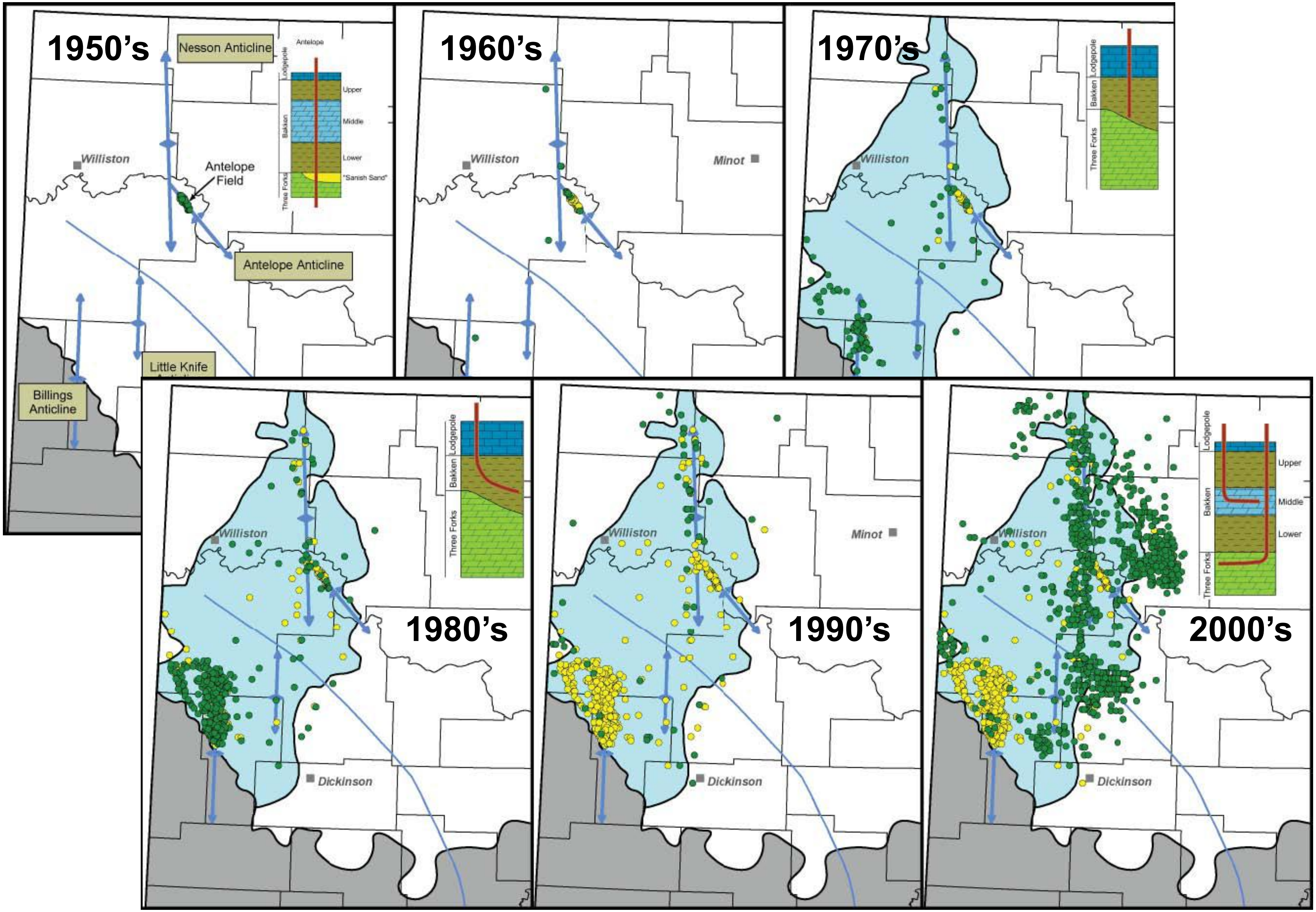


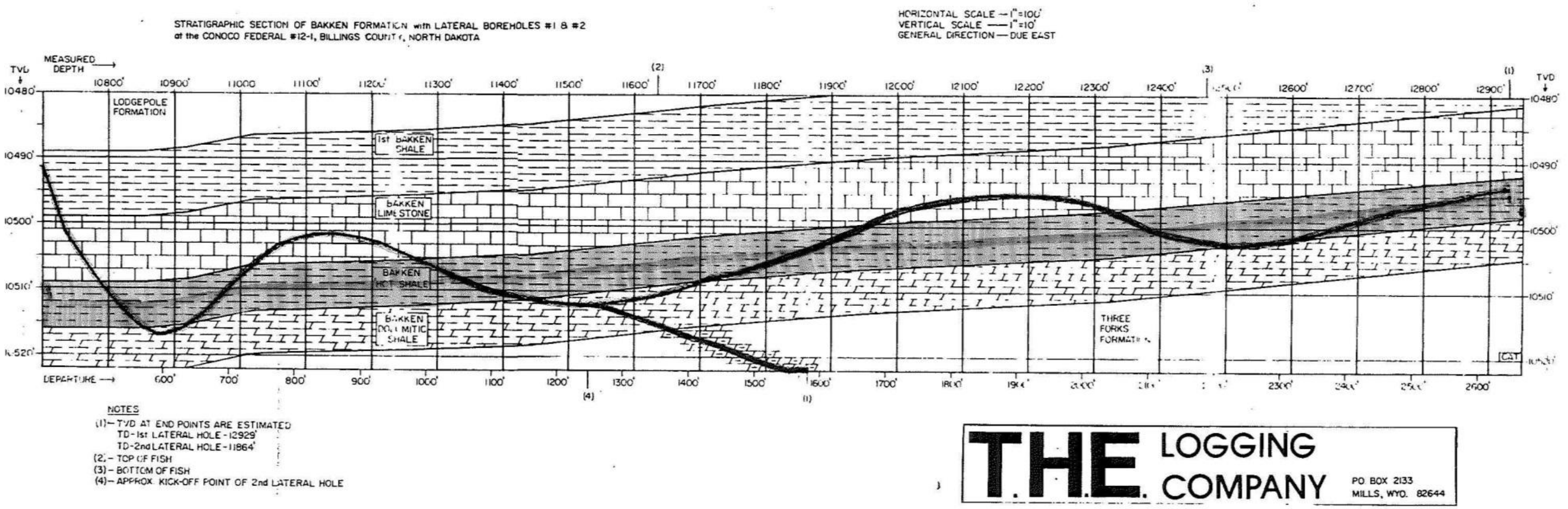
Fig. 19. Parshall field well log

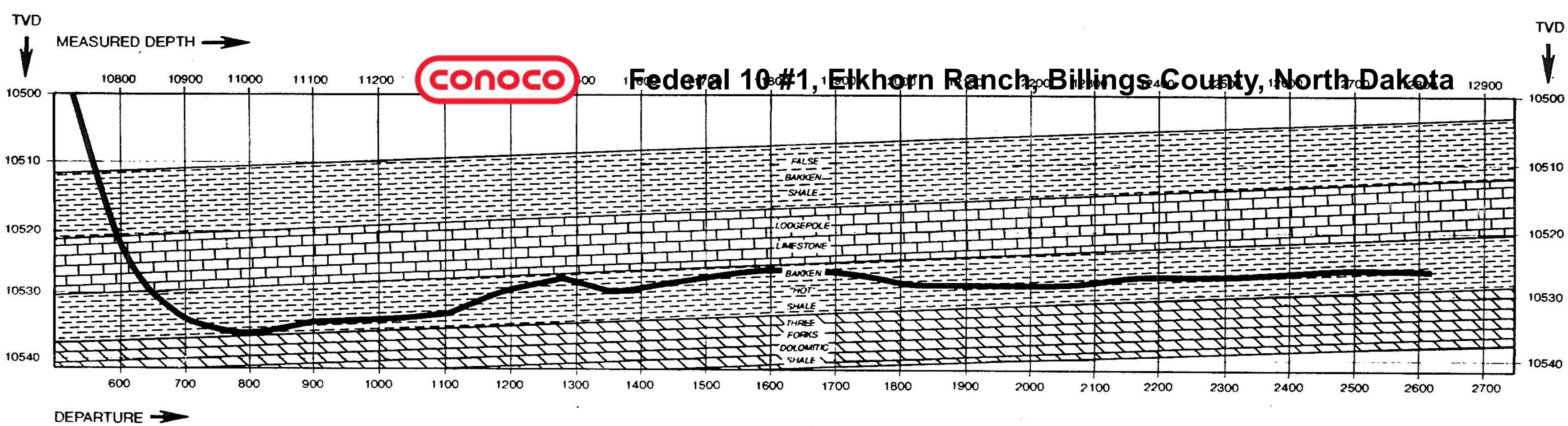
The Upper and Lower Bakken organic black shale members serve as both source rock and reservoirs. The Middle Bakken is a conventional, but tight, clastic and carbonate reservoir. The upper Three Forks can have similar characteristics as the Middle Bakken and be a target as well. Long-term production analysis indicates Bakken Upper and Lower Shales can be significant contributors of overall storage in the system. *(Hough and McClurg, 2011, Impact of Geological Variation and Completion Type in the U.S. Bakken Oil Shale Play Using Decline Curve Analysis and Transient Flow Character*;*
*Search and Discovery Article #40857; *Adapted from oral presentation at AAPG International Conference and Exhibition, Milan, Italy, October 23-26, 2011*

Bakken Drilling/Development History



Early Horizontal Drilling Attempts





Bakken Stratigraphy

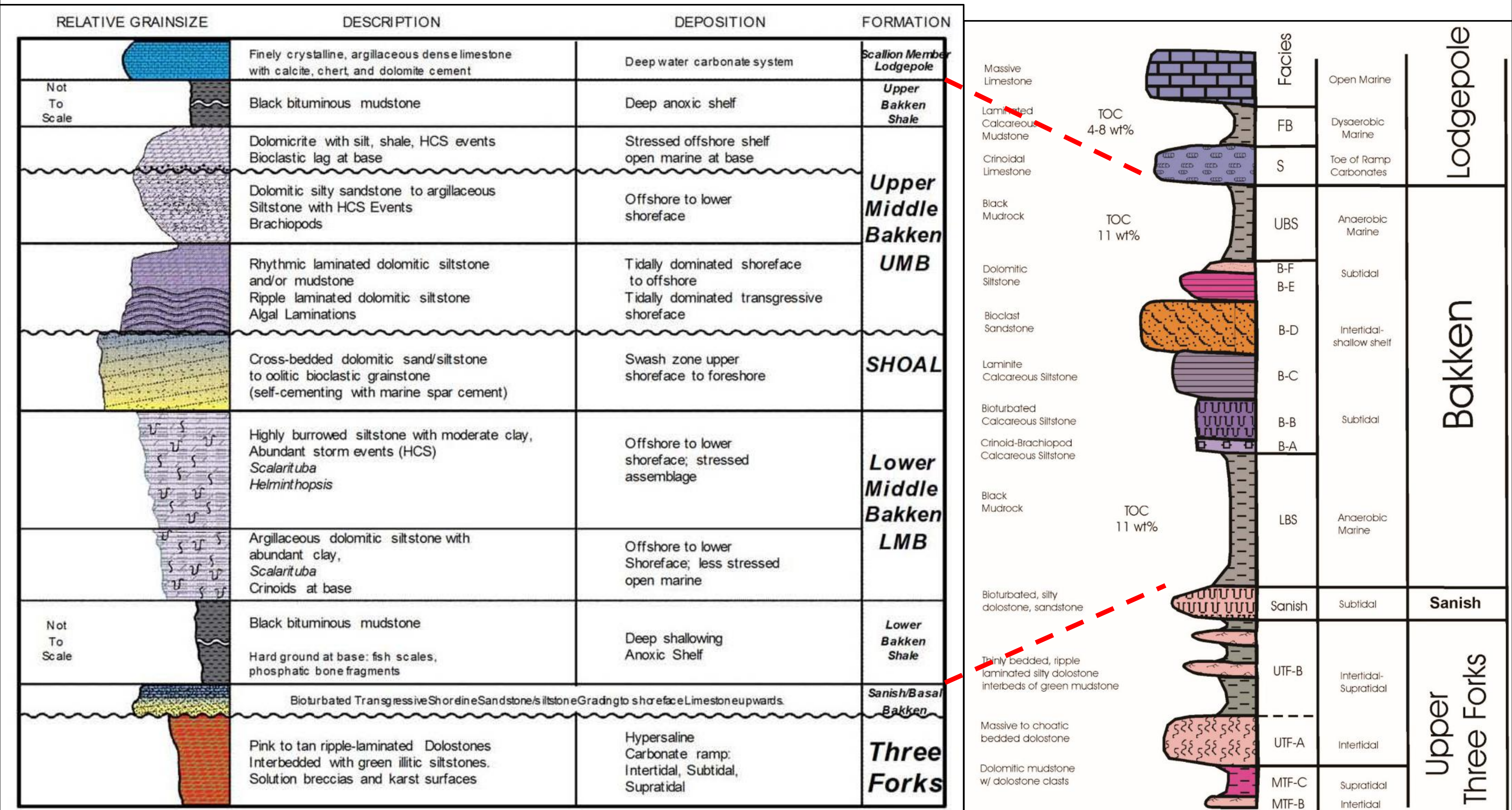
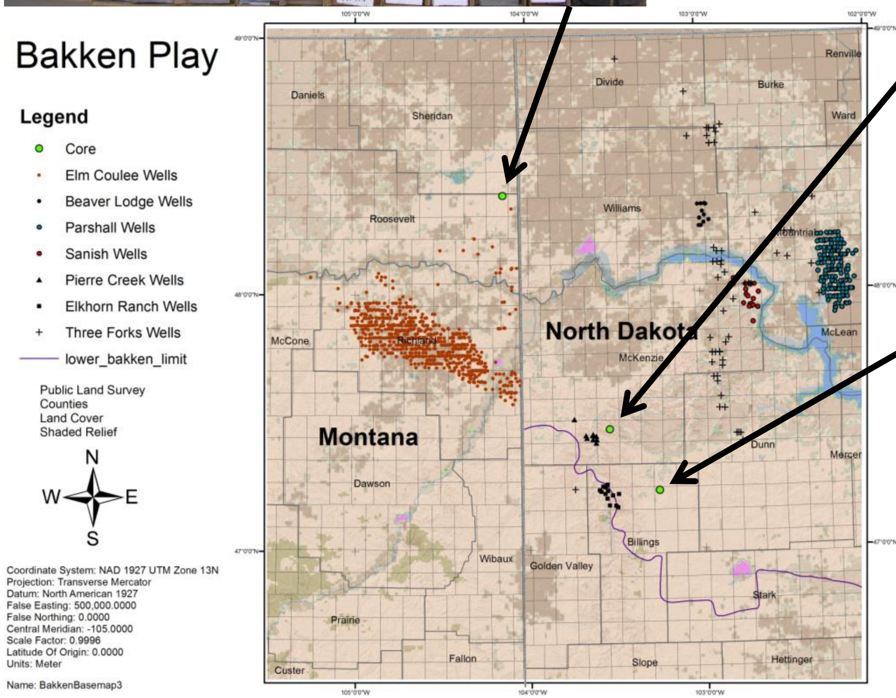


Figure 9. Bakken stratigraphy and facies description from interpretation of Bakken and Three Forks cores throughout the basin.

Source: Grau, et al, 2011, Characterization of the Bakken Reservoir at Parshall Field and East of the Nesson Anticline, North Dakota, in The Bakken–Three Forks Petroleum System in the Williston Basin, John W. Robinson, Julie A. LeFever, Stephanie B. Gaswirth, eds. Denver, Colo.: Rocky Mountain Association of Geologists, 2011.

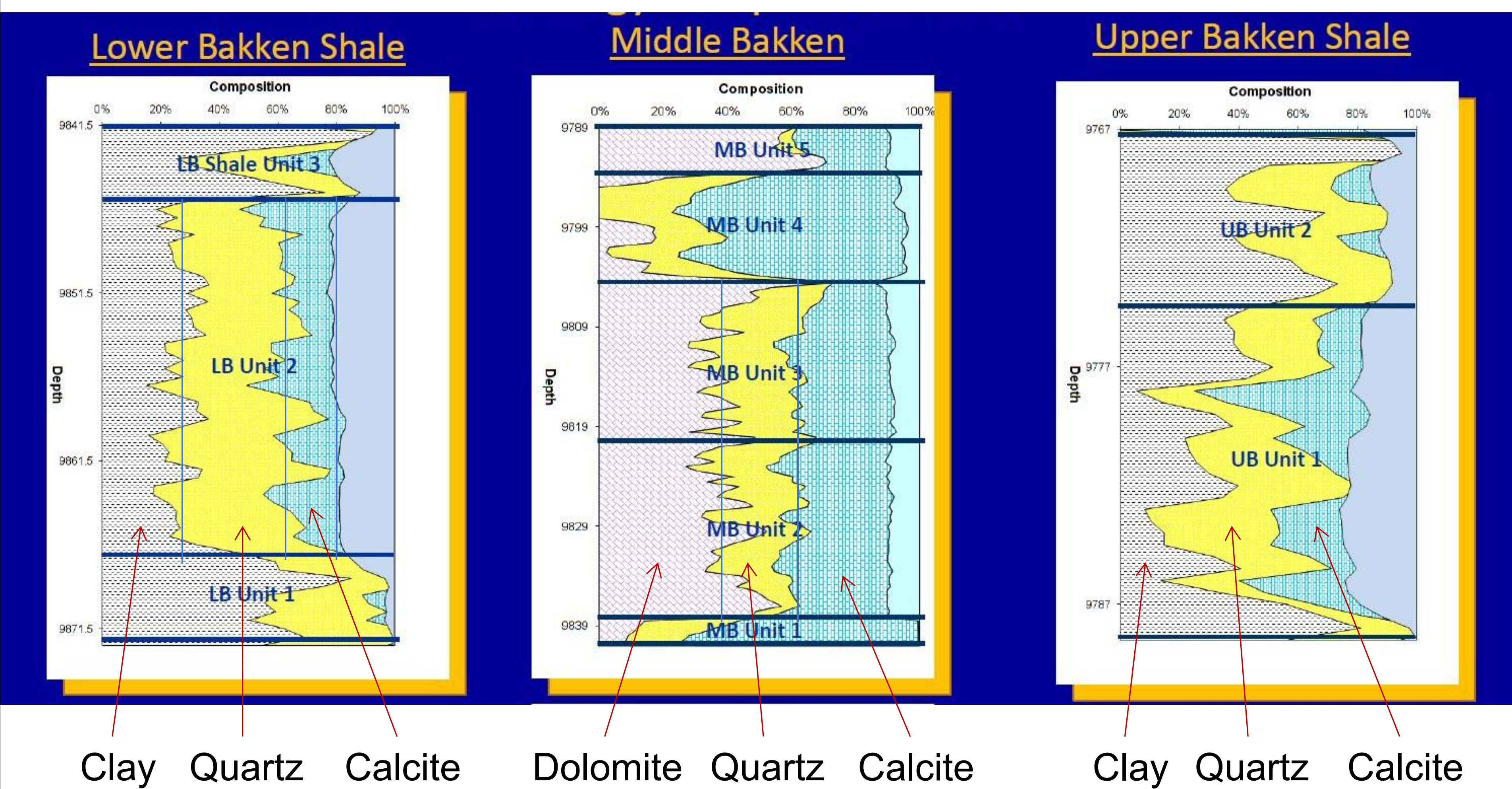
Core examination Bakken

Pennzoil 15-22 Depo
Sec 15-T146N-R101
McKenzie Co. ND



Texaco 1-5 Thompso
Sec 5-T143N-R99W
Billings Co. ND

Bakken Mineralogy



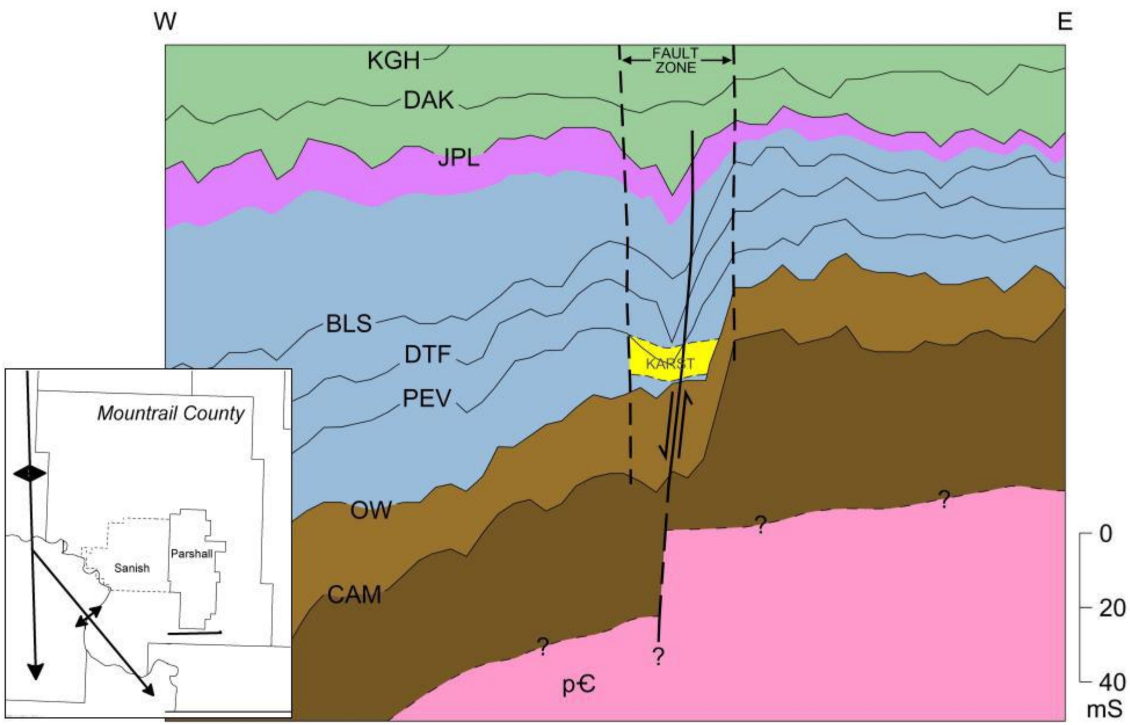
Carbonate = Dolomite + Calcite

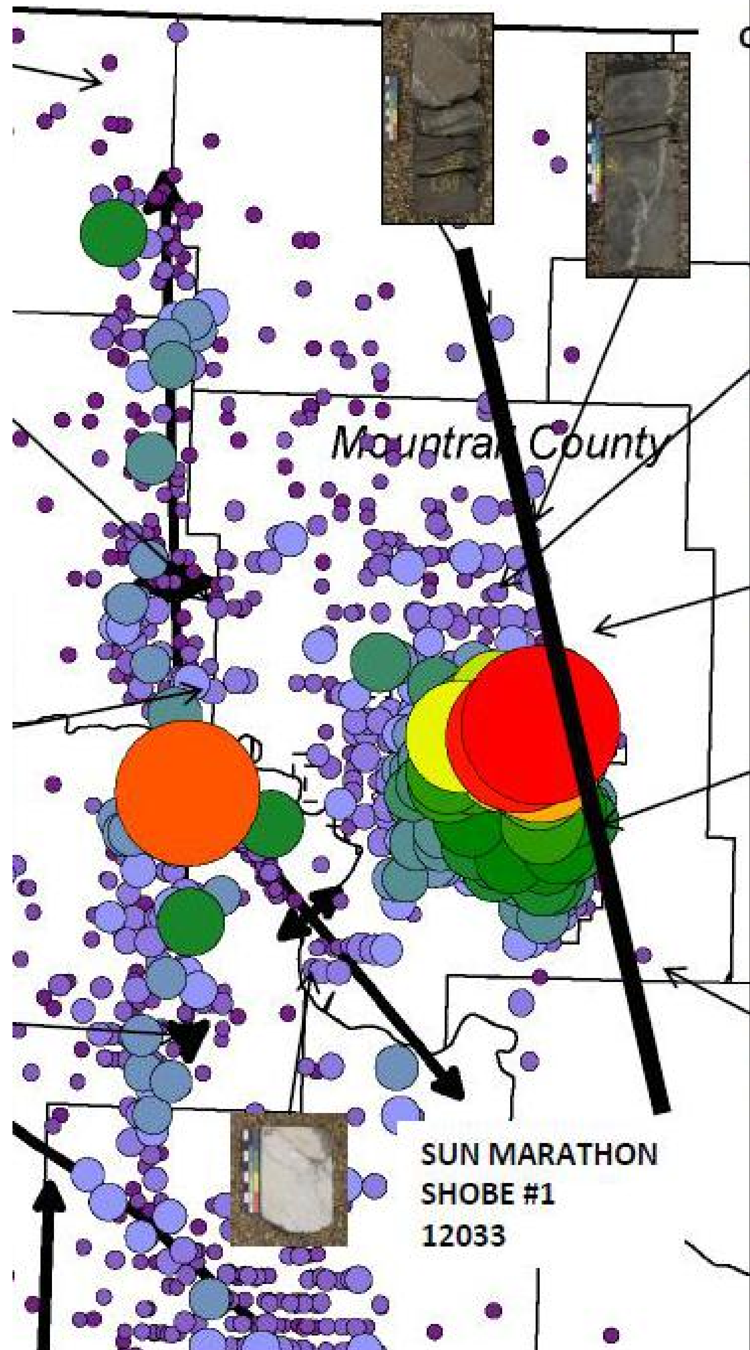
Steptoe and Carr 2011 AAPG Bakken poster

“Oil Generation Rates and Subtle Structural Flexure: Keys to Forming the Bakken Sweetspot in the Parshall Field of Mountrail County, North Dakota”

Nordeng, et al, 2010, NDGS (AAPG)

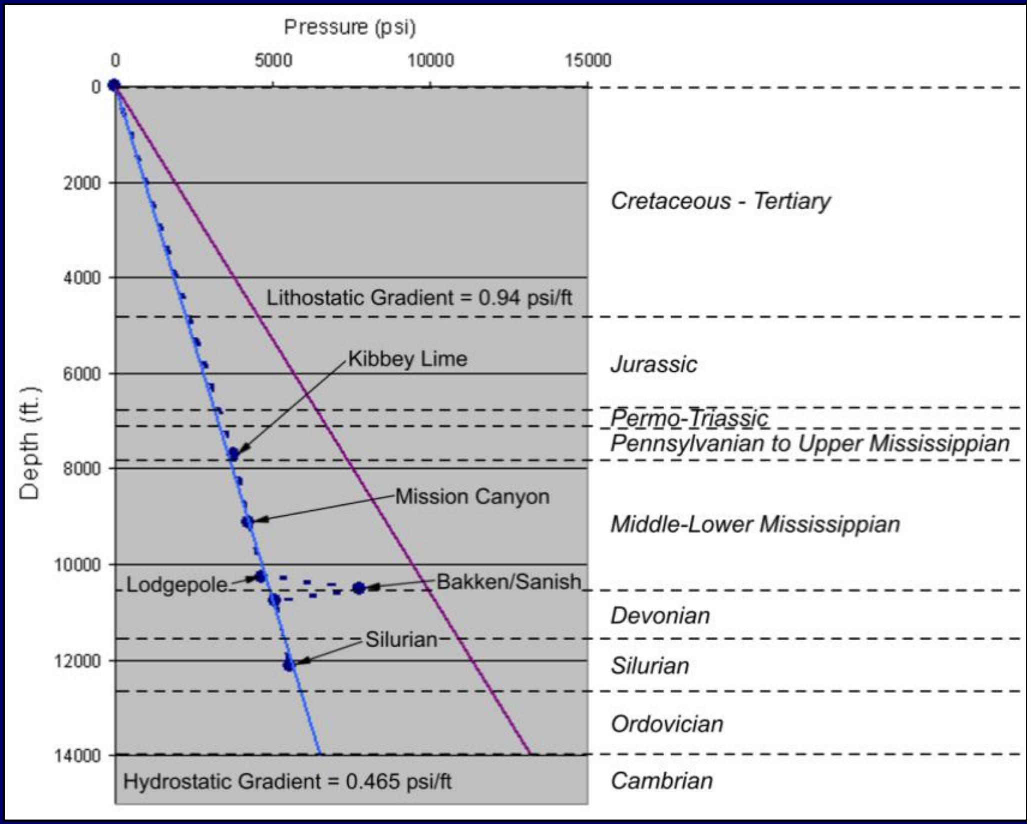
Interpreted 2-D seismic line showing local flexure extending up through section.



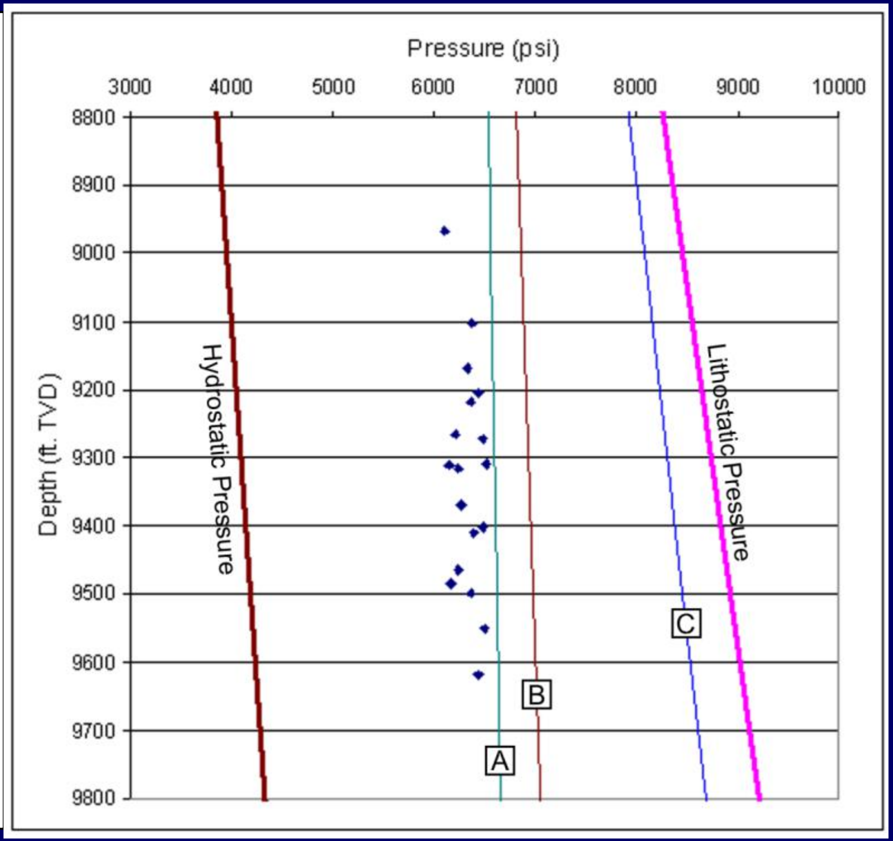


Overpressure in the Bakken

Example 1 – Antelope Field, North Dakota (Bakken/Sanish sand):



Example 2 – Parshall Field, North Dakota (Bakken):



Source: Oil Generation Rates and Subtle Structural Flexure: Keys to Forming the Bakken Sweetspot in the Parshall Field of Mountrail County, North D
Stephan H. Nordeng1, Julie A. Lefever3, Fred J. Anderson1, and Eric H. Johnson2; Search and Discovery Article #20094 (2010); Posted October 22,
**Adapted from oral presentation at AAPG Rocky Mountain Section 58th Annual Rocky Mountain Rendezvous, Durango, Colorado, June 13-16, 2010*

Learnings

- CBM, Tight Sand Gas, Shale Gas, and Tight Oil are primary unconventional resources
- Low mobility from low permeability results in the unconventional reservoir. SR quality, tectonics, sedimentology, petrophysics, gas content, mineralogy, geomechanics, etc. all matter
- Organic rich shale-past source rocks to current reservoirs
- Complex shale lithofacies: shale to fine grained tight carbonate/siltstone and hybrid plays, most shale oil plays are fine-grained tight plays
- Traditional reservoir prediction method may not work for some plays, e.g. siliceous high TOC shale vs carbonate-rich low TOC shale
- Production performance vary depending shale geology and reservoir conditions (tectonic, depositional, TOC, mineralogy, pressure, porosity, fracture, etc.). Tectonically stable area is key for shale gas E&P.
- Sweet spot determined by both favorable geology and frackable engineering parameters
- Lacustrine model of hybrid shale related plays will work for ASEAN, South America, Africa countries

Chapter 8 Unconventional Hydrocarbon Reservoirs

Section 1 Introduction of Unconventional Hydrocarbon Reservoirs

Section 2 Reservoir Characterization Of Unconventional Reservoirs (tight sand, CBM, shale)

Section 3 Development of Unconventional Hydrocarbon Reservoirs

Glossary of Terms

EUR — Estimated Ultimate Recoverable reserves from a well

OGIP — Original Gas in Place before production (usually quoted in billions or trillions of cubic feet)

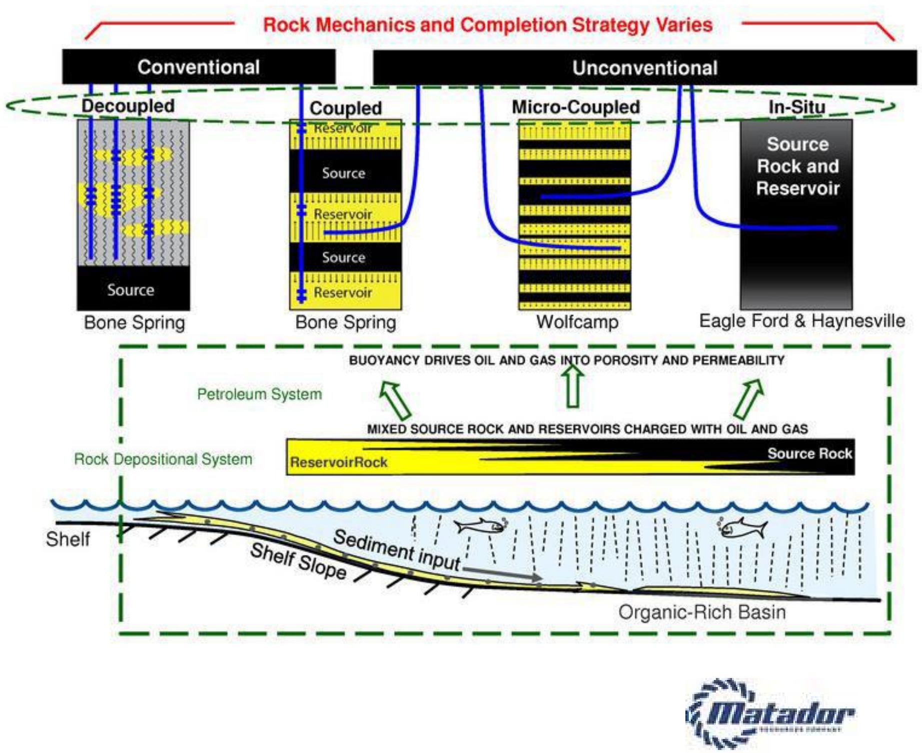
IP — Initial production rate of a gas well – often much higher than the sustained production rate – usually quoted as millions or thousands of cubic feet per day (Mmcf/d or mcf/d)

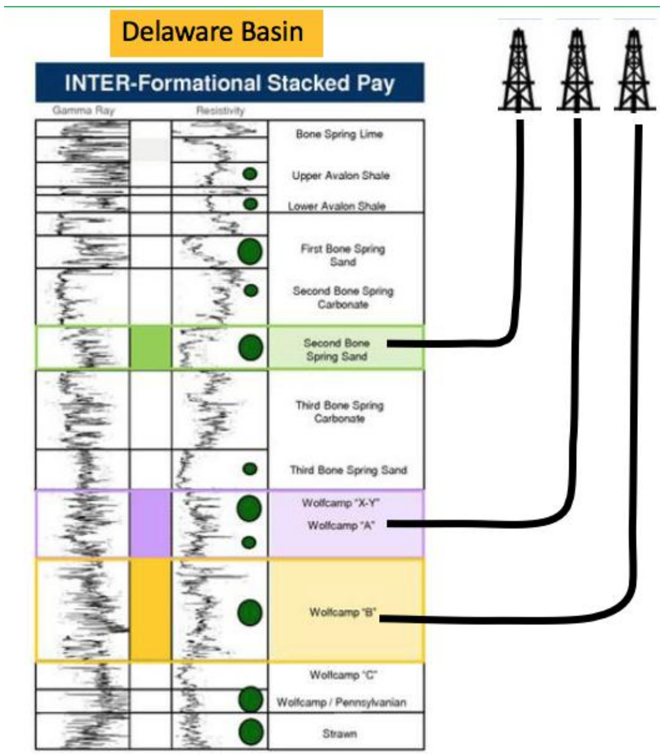
Hydraulic Fracturing — Commonly referred to as fracing, this is the process where the reservoir rock is cracked using pressure and fluids to create a series of fractures in the rock through which the natural gas will flow to the wellbore

Multi-Stage Fracturing — The process of undertaking multiple fracture stimulations in the reservoir section where selected parts of the reservoir are isolated and fractured separately

Microseismic — The methods by which fracturing of the reservoir can be observed by geophysical methods to determine where the fractures occurred within the reservoir

Development Strategies

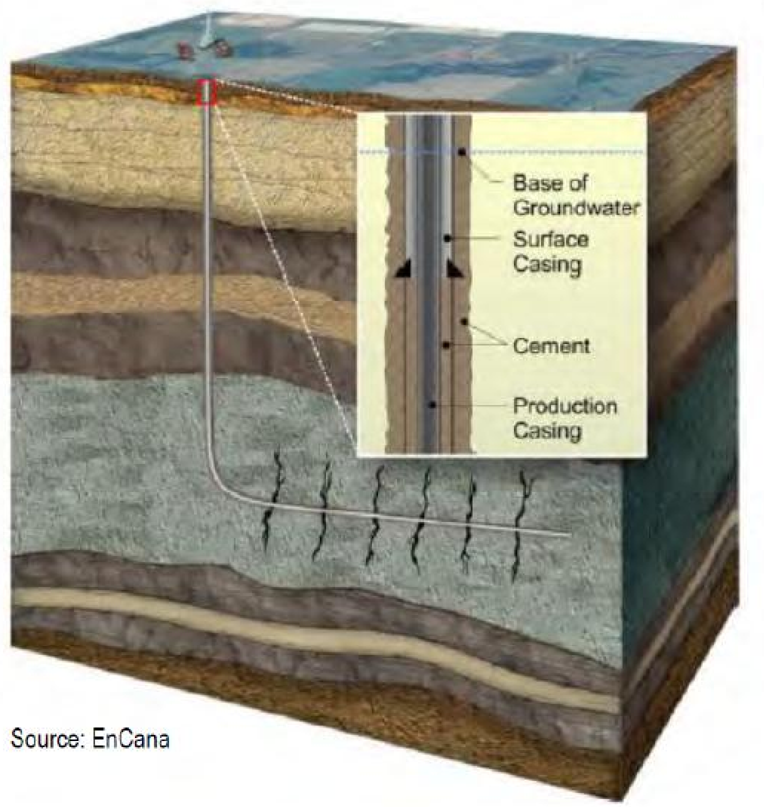




Drillinginfo: While most of the Permian strata have been developed by conventional methods over many decades, vast resources are being explored by unconventional drilling

What Made Unconventional Development Successful

- The price of gas has always been the driving factor
- Production in Appalachian and Michigan basins for decades
- Technologies that drove change are horizontal drilling, low viscosity treatments, intensive stimulation.



Source: EnCana

Development Technologies

- Accessing the Reservoir - Why and How
- Drilling and Completion Technologies
  - Coiled Tubing Drilling
  - Horizontal Drilling
  - Multi-Lateral Drilling
- Completion and Stimulation Techniques
  - Vertical Fracture Stimulations and Co-Mingling
  - Multi-Stage Fracture Stimulation Techniques
  - Micro-Seismic Monitoring to Determine Effectiveness of Stimulation
- Gas Factory Ideology
  - Optimization of Reservoir Production
  - Key Aspects of Unconventional Gas Development
  - Stages of Exploration and Development
  - Economies of Scale and Economic Benefits

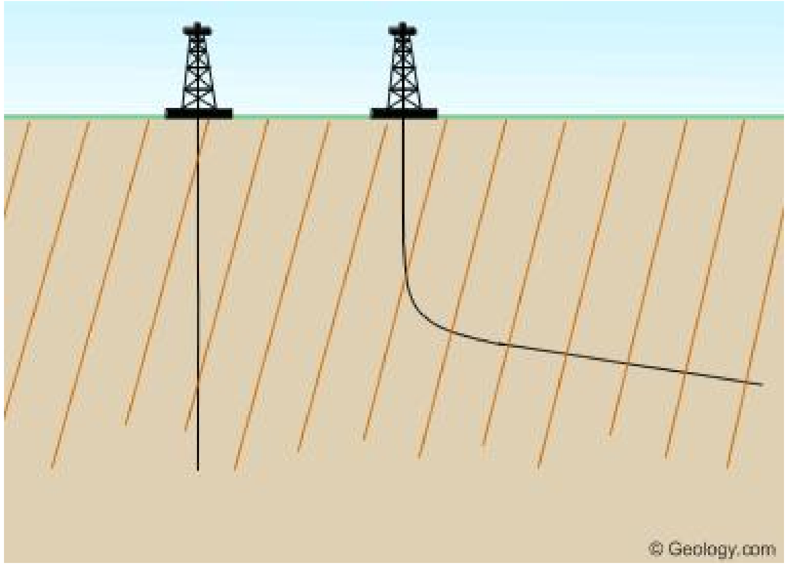
Accessing the Reservoir

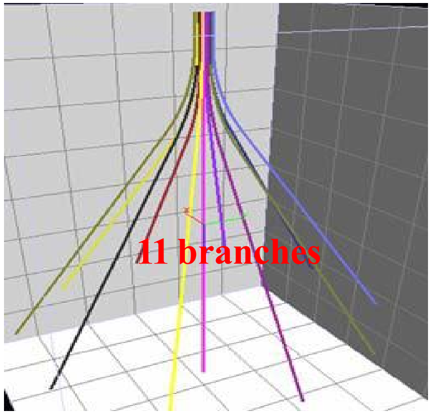
- The fundamental purpose of drilling a oil or gas wellbore is to intersect the maximum amount of pay zone within the reservoir and optimize the productivity from the wellbore
- In unconventional reservoirs the ability of the hydrocarbons to flow to the well is hindered due to lower permeability
- To counter this lower productivity, drilling and stimulation techniques are used to maximize the amount of the reservoir exposed to the wellbore
- Techniques include:
  - Vertical well multi-zone stimulation
  - Horizontal wells
  - Multistage fracturing

- Essentially all unconventional gas reservoirs require some form of improved access either through drilling or hydraulic fracturing

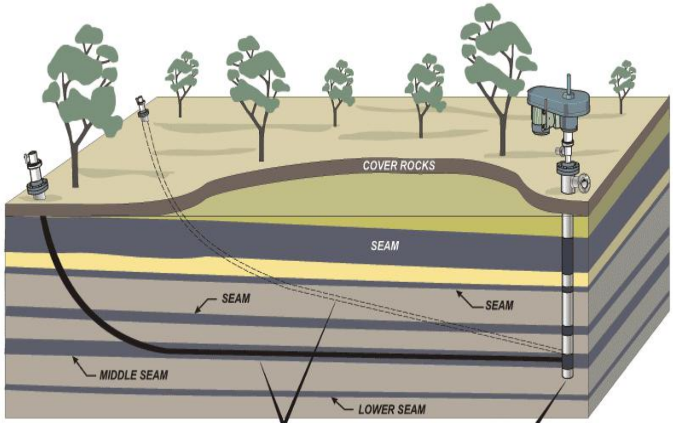
Drilling

Cluster wells (Small footprint)





Ruichen Shen et al., 2015, AAPG



U-type Horizontal Well

Drilling and Completion Technologies

Different types of drilling equipment and methodology are available dependent on reservoir depth, thickness and expected flow properties

Some choices include:

Coiled Tubing Drilling and multi-zone completions Horizontal Drilling with mono reservoir completion Multi-Lateral Drilling with multiple completions

Drilling Efficiencies and Savings have been achieved through:

- ➢Speed of drilling using new bit technology (P bits achieve penetration rates of up to 80 m/h
- ➢Multiple drill string assemblies that reduce tripping time
- ➢Geosteering in real time in horizontal and multilateral wells
- ➢Automation of rig floor equipment eliminating additional manpower
- ➢Fit for purpose rigs that can move on site without teardown

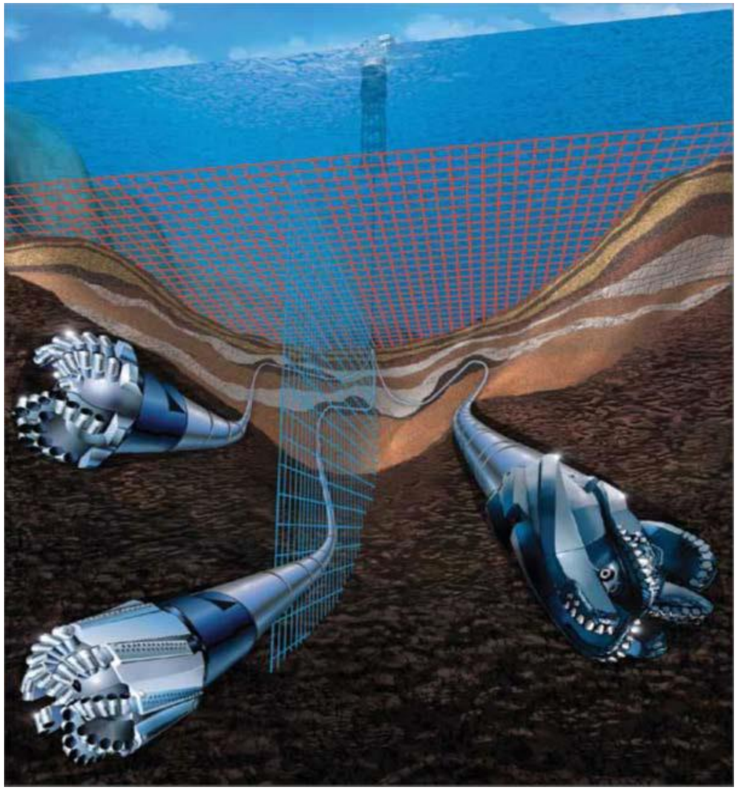
From Range Resources, 2010

Eg. Range Resources operates two fit for purpos drilling rigs that can move to the next well location on a common pad with over 3000 m of drill pipe stacked on the derrick – rig move reduced from days to hours

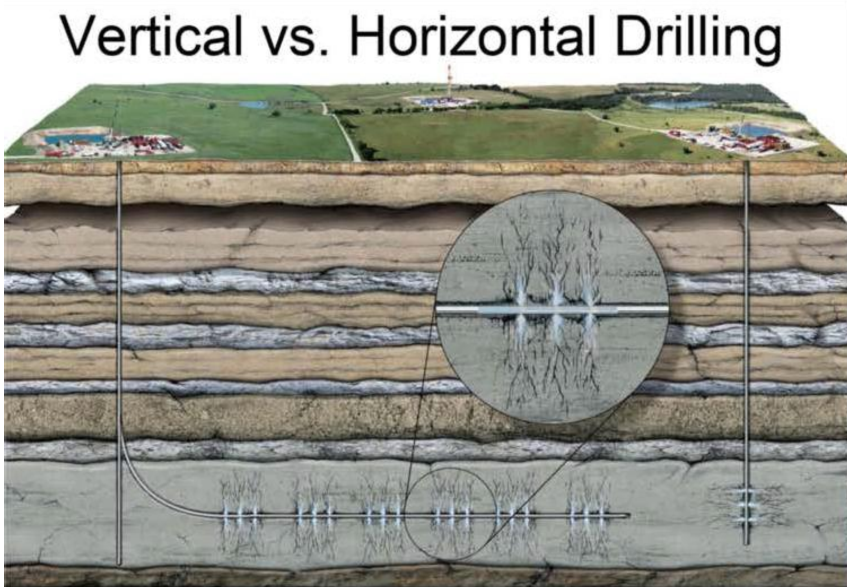
Drilling and Completion Technologies

Geosteering of horizontal wells in real time allows optimal reservoir penetration

Multiple well orientations either vertical or horizontal from single surface well pads minimizes footprint



courtesy Halliburton



•Drilling of horizontal wells with the horizontal legs being up to 3500 m in length

•Multi stage fracture stimulations using slick water and sand to essentially “create reservoir” in rock that would not have been considered reservoir quality previously

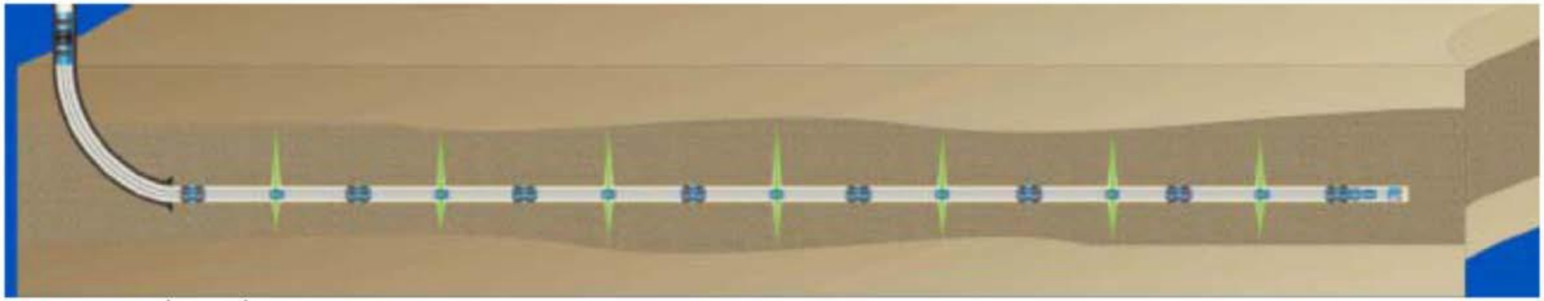
Zonal isolation packer systems in horizontal and multi-lateral wells allow for selective stimulation as well as production

Horizontal Wellbore and Multi-Lateral Wellbore Completions

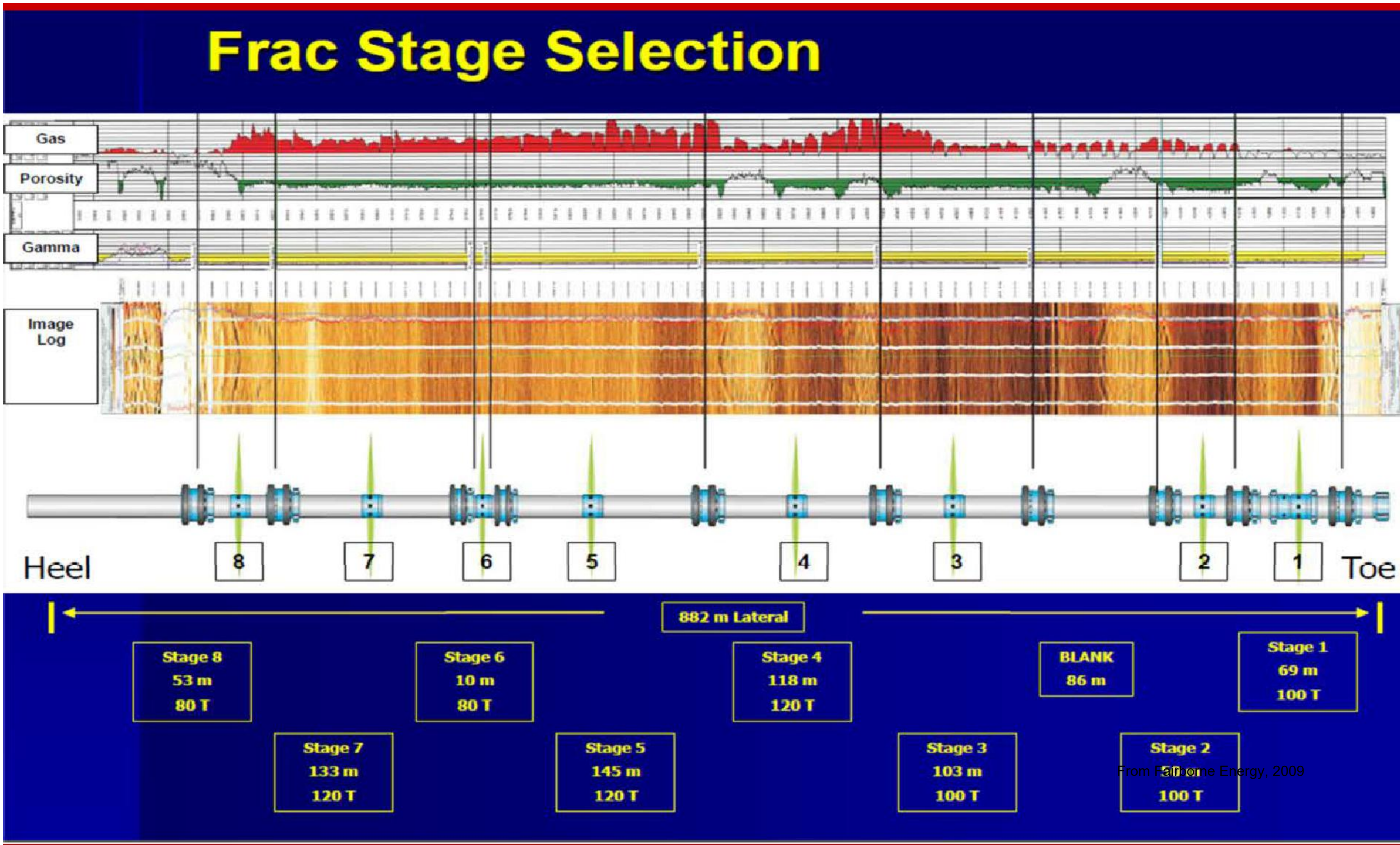
- Commonly multi-stage fracture stimulations are conducted to optimize the amount of fracture energy entering into the wellbore

- The horizontal leg is broken into stages where fracture stimulation for each stage is isolated from the rest of the wellbore

- Fracture design for each stage within the horizontal leg is dependent on borehole logging indicators of gas concentration as well as natural fracture density



Source: Packers Plus Energy Services Inc.


Frac Stage Selection
Gas
Porosity
Gamma
Image Log
8
7
6
5
4
3
2
1
Heel
Toe
882 m Lateral
Stage 8 53 m 80 T
Stage 7 133 m 120 T
Stage 6 10 m 80 T
Stage 5 145 m 120 T
Stage 4 118 m 120 T
Stage 3 103 m 100 T
BLANK 86 m
Stage 2 100 T
Stage 1 69 m 100 T
From Fairborne Energy, 2009

How Do We Measure Success in Reservoir Stimulation

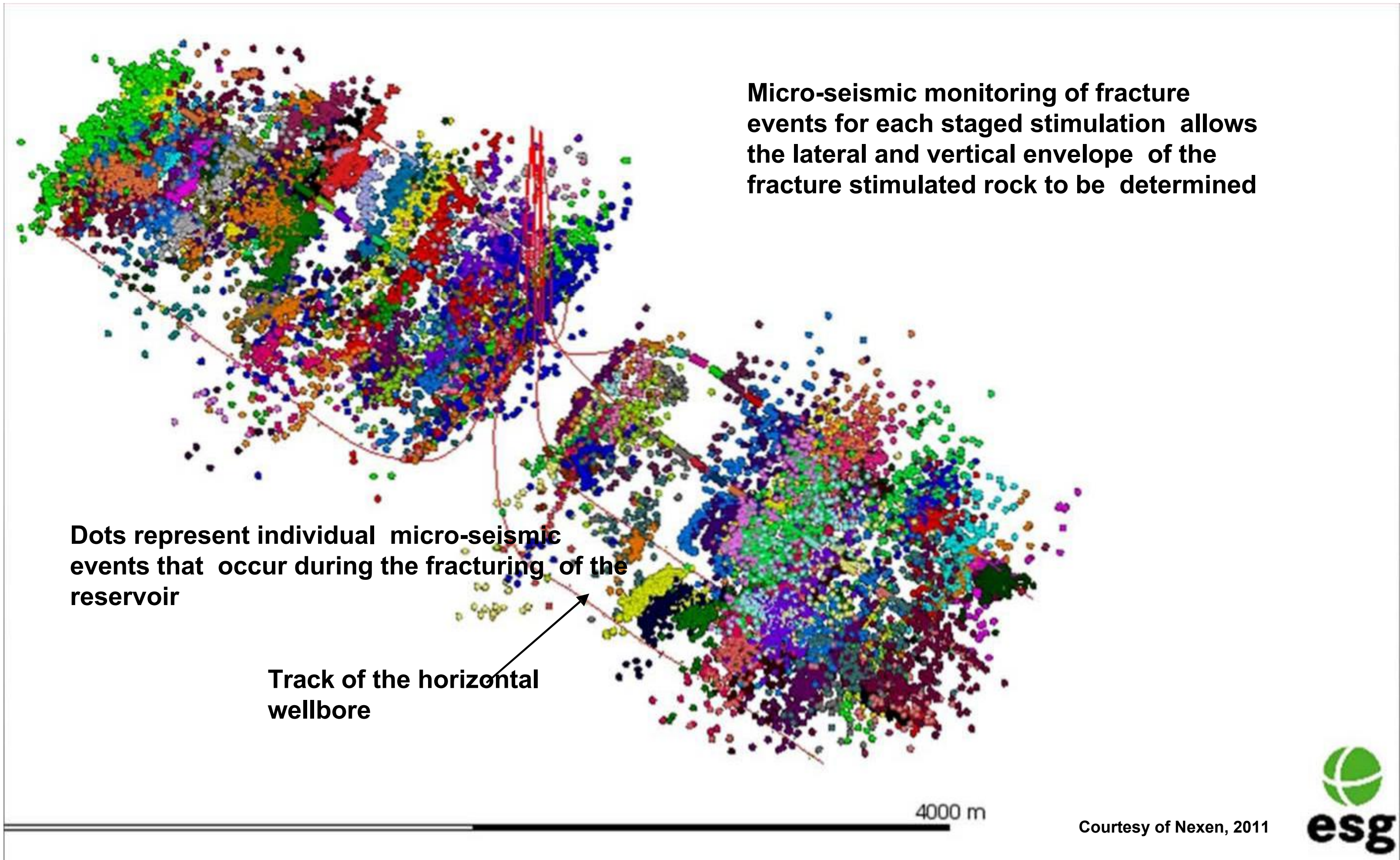
Micro-Seismic to Determine Effectiveness of Stimulation

- Measures micro seismic events related to the propagation of fractures within the reservoir

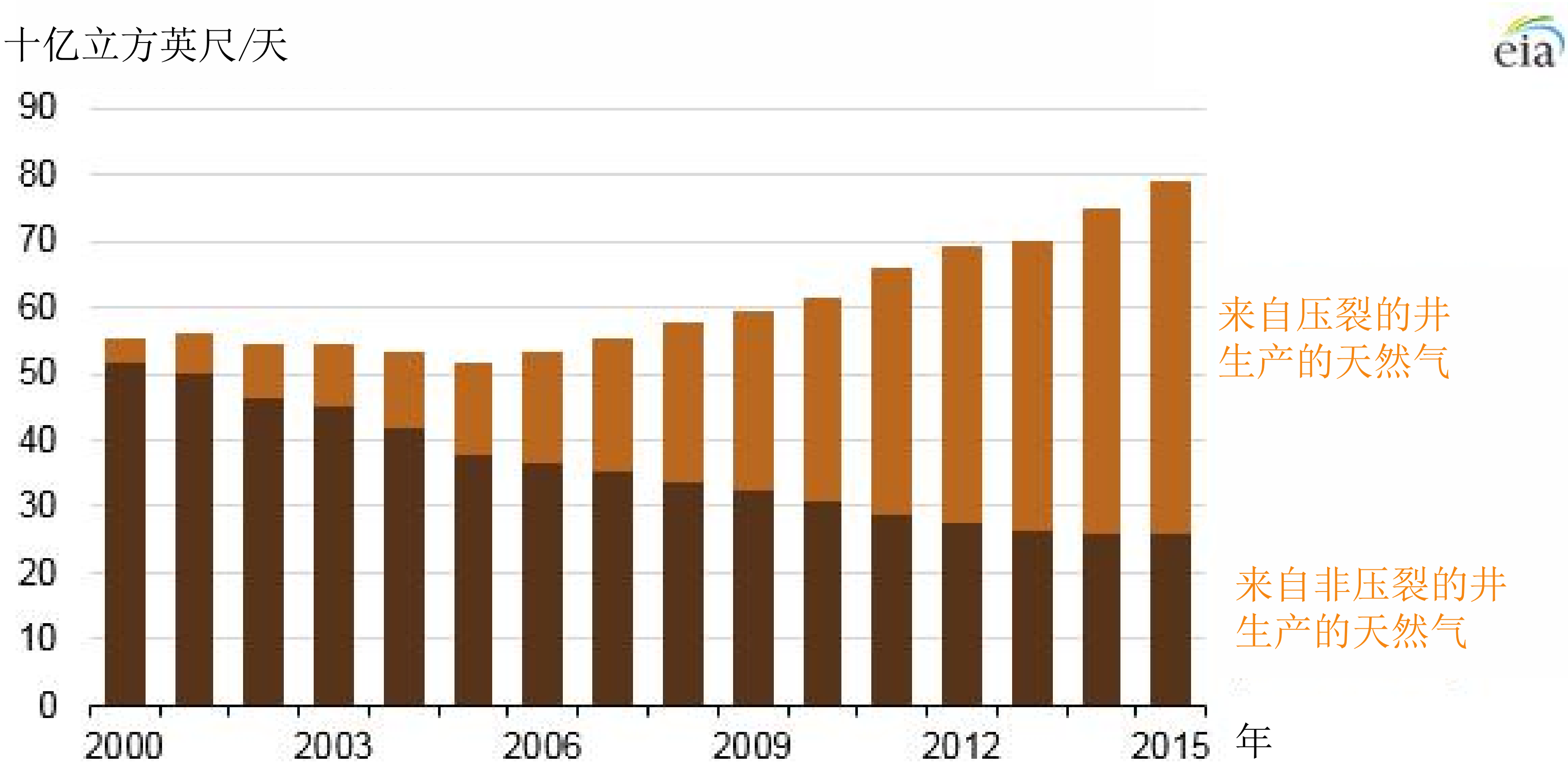
- Requires one or more observation wells to allow proper mapping of location geographically and vertically of microseismic events

- Can be run independently or as permanent seismic arrays in field to be developed

- Provides a 3D image of fracture propagation that can be measured in real time during the fracture stages
  - Allows fracture propagation trends to be identified and adjusted for additional stages so fractures can be contained within zone
  - Identifies areas of poor fracture generation or geological barriers to effective stimulation


Micro-seismic monitoring of fracture events for each staged stimulation allows the lateral and vertical envelope of the fracture stimulated rock to be determined
Dots represent individual micro-seismic events that occur during the fracturing of the reservoir
Track of the horizontal wellbore
4000 m
Courtesy of Nexen, 2011

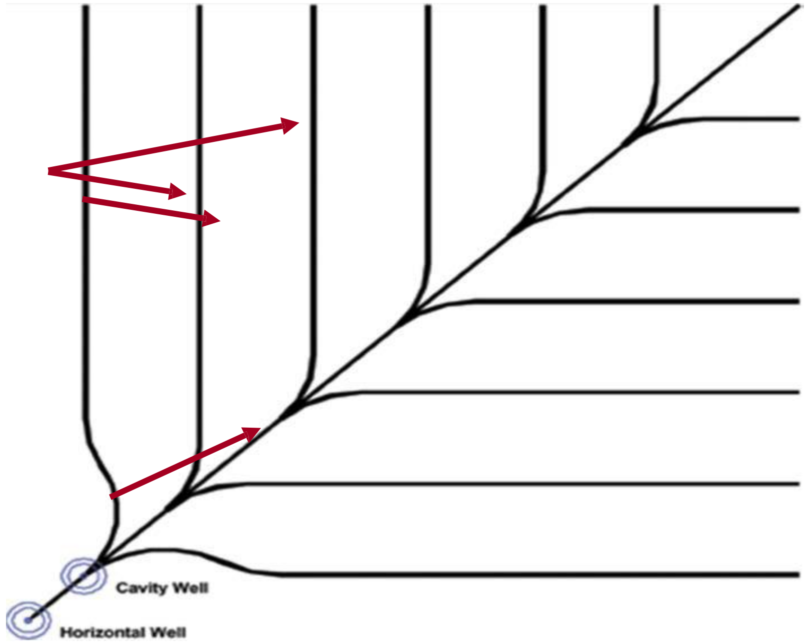
Role of Hydraulic Fracturing



EIA, 2016

Drilling and Completion Technologies

Horizontal Drilling/ Multi-Lateral Drilling



The Pinnate Drainage Pattern

Completion and Stimulation Techniques

- Fracture stimulations are required for most unconventional resource plays due to low permeabilities of the reservoirs

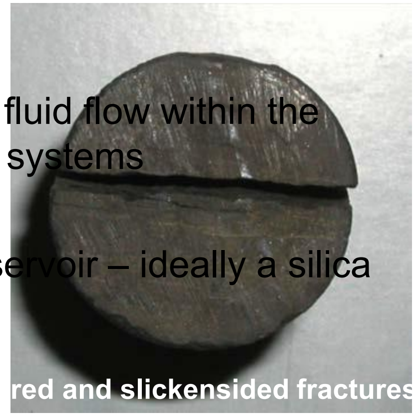
- Type of fracture stimulation used is defined by:
  - ➢Depth and number of reservoirs to be stimulated
  - ➢Reservoir quality
  - ➢Type of wellbore (vertical versus horizontal)
  - ➢Fluid sensitivity
  - ➢Geomechanical properties of the reservoir
  - ➢Availability of equipment and materials
  - ➢Economic assessment of wellbore deliverability

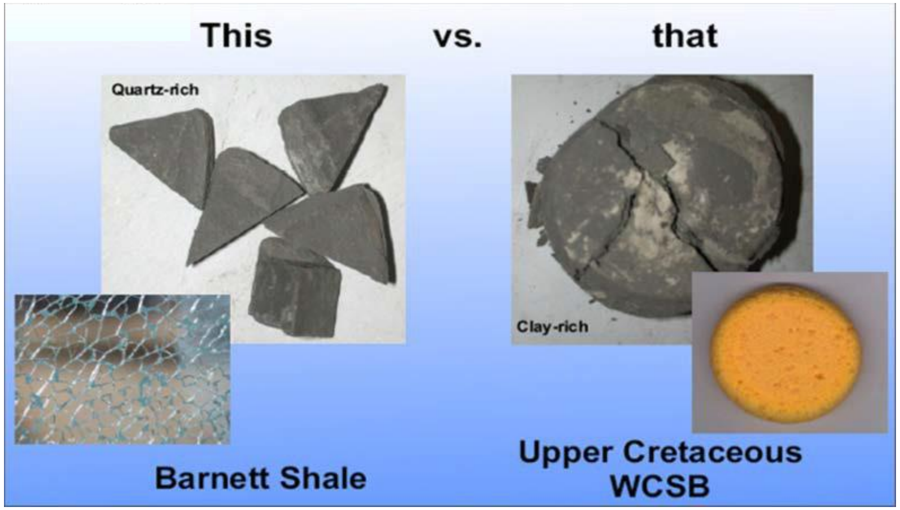
Fracture Stimulation Parameters

The main purpose of fracture stimulation is to create open pathways for fluid flow within the reservoir either by creation of fractures or intersection of existing fracture systems

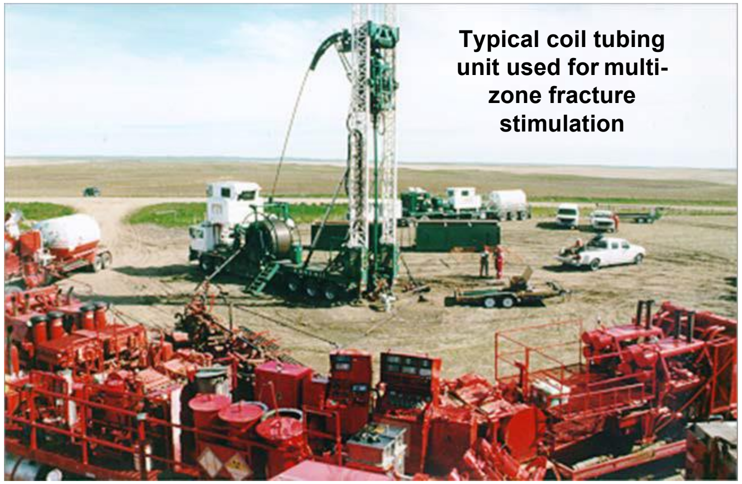
Ideally the reservoir rock should be "brittle" so that it fractures easily

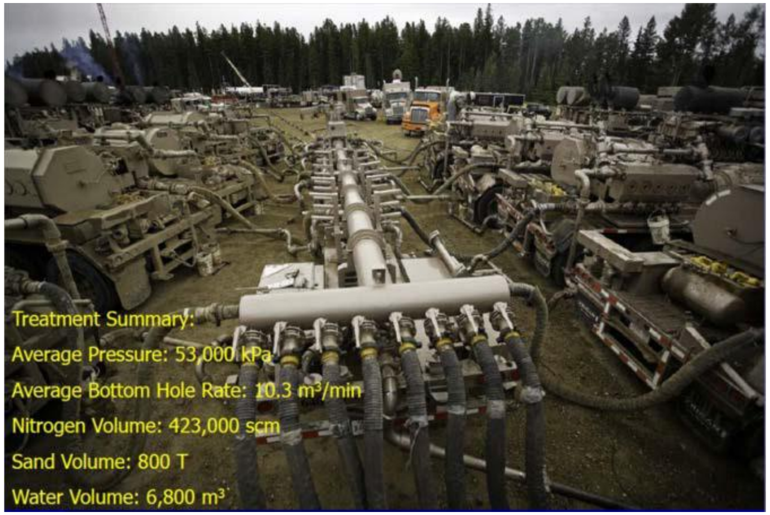
Mineral content of the shale component will determine "fracability" of reservoir – ideally a silica rich shale is preferred





Open vertical fractures





Completion techniques as well as size and amount of equipment will be dependent on the depth of the reservoir, size of fracture stimulation and number of fracs designed for the well

Courtesy of Halliburton, 2009

Economies Through "Manufacturing Style"

Fracture stimulation costs now account for more than half of the total well costs

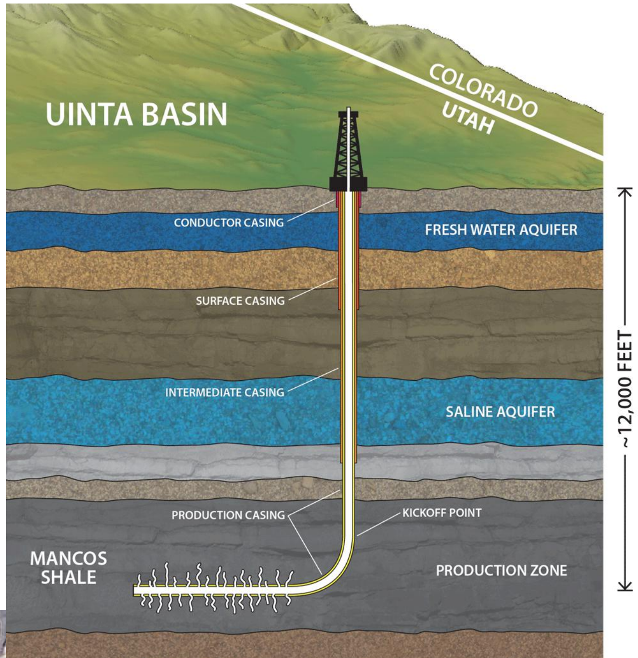
- **Minimize completion time**
- **Mitigate operational risk**
- **Define synergies and economies of scale**
- **Maximize EUR - completion methods which are adaptable to future recompletion capabilities reserves**
- **Minimize Logistics Costs: Re-using water from flowback and production, innovative fluid handling & storage**
- **Minimize Surface Impact & Costs: Pad drilling and completions, multi-lateral capability**

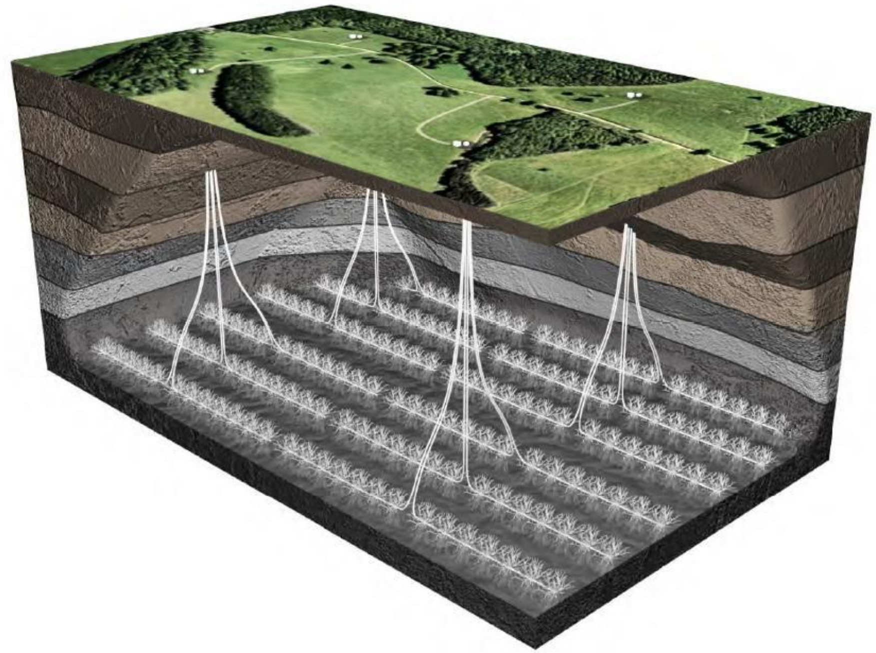
from E. Schmelzel, 2008

Completion and Stimulation Techniques

- Multi-stage fracture stimulations are labor and equipment intensive that requires planning for wellsite activities as well as supply of frac materials (sand and water primarily)
- Multi-stage fracture stimulations are costly and should be undertaken only after reservoir properties have been tested from vertical wellbores and core data

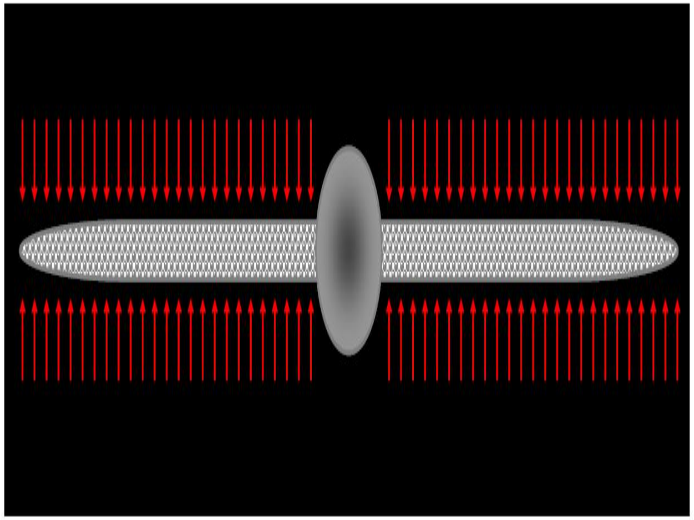
Hydraulic Fracturing





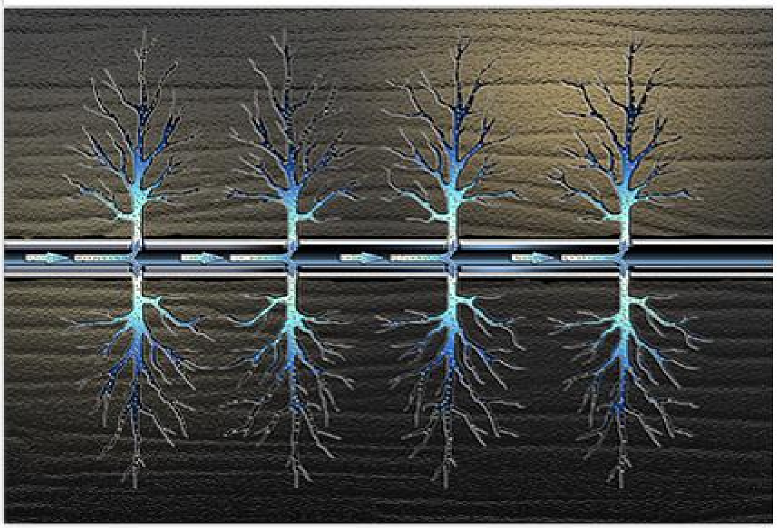
Oil and gas fracking wells.

- Frac Target



Simple Bi-wing.

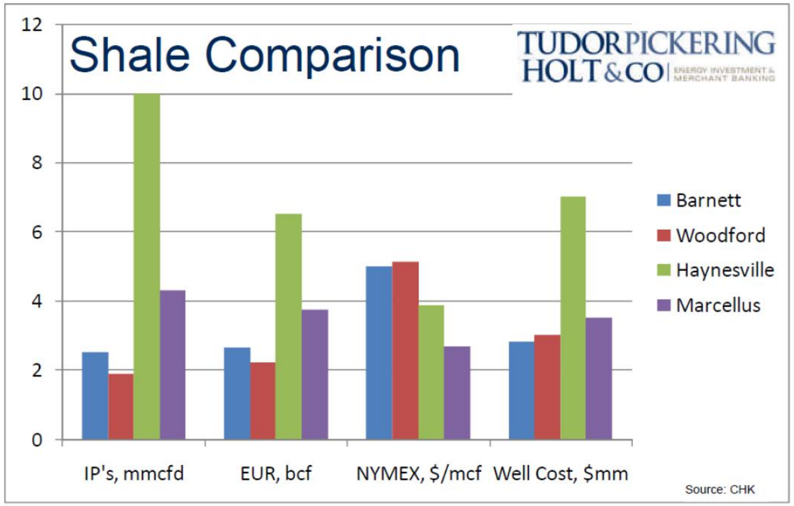
Common used one in conventional reservoirs



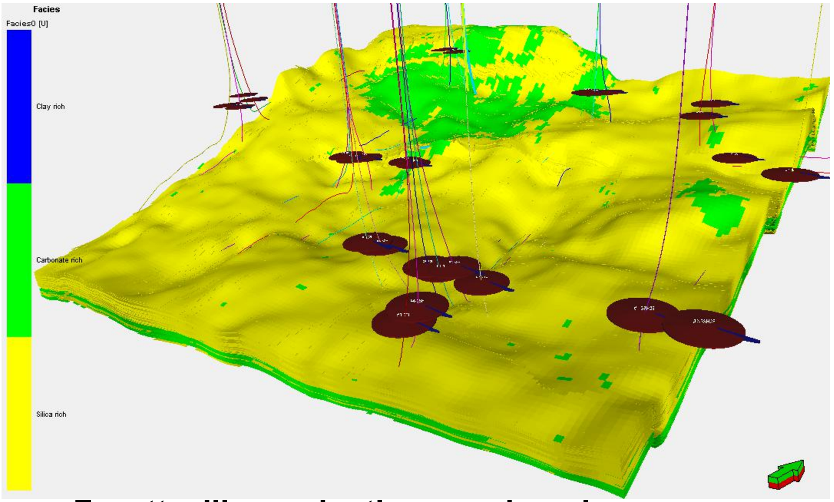
Intensive Complex Frac.

Massive frac is needed for unconventional shale gas

Geologic Control on US Shale Production



High production from sweet spot with high TOC, high porosity, high pressure, high brittle mineral content, etc.

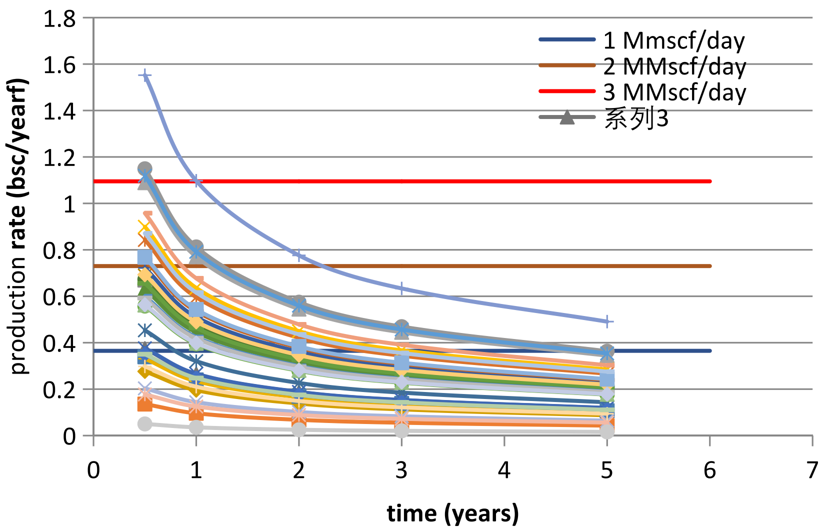


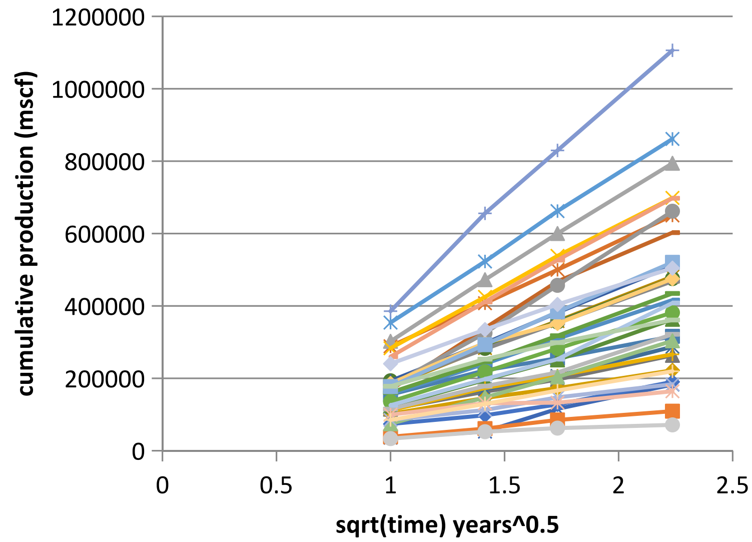
Fayetteville production vs mineralogy

Shale	Haynesville	Barnett	Fayetteville
TOC(%)	3	4.5	2-5%
Pressure gradient (psi/ft)	0.95	0.526	0.42
Quartz content(%)	10-40%	41	40-60%
Porosity(%)	10	6	4

data from M. Roth, 2010 and various resources

Production Model and Analysis





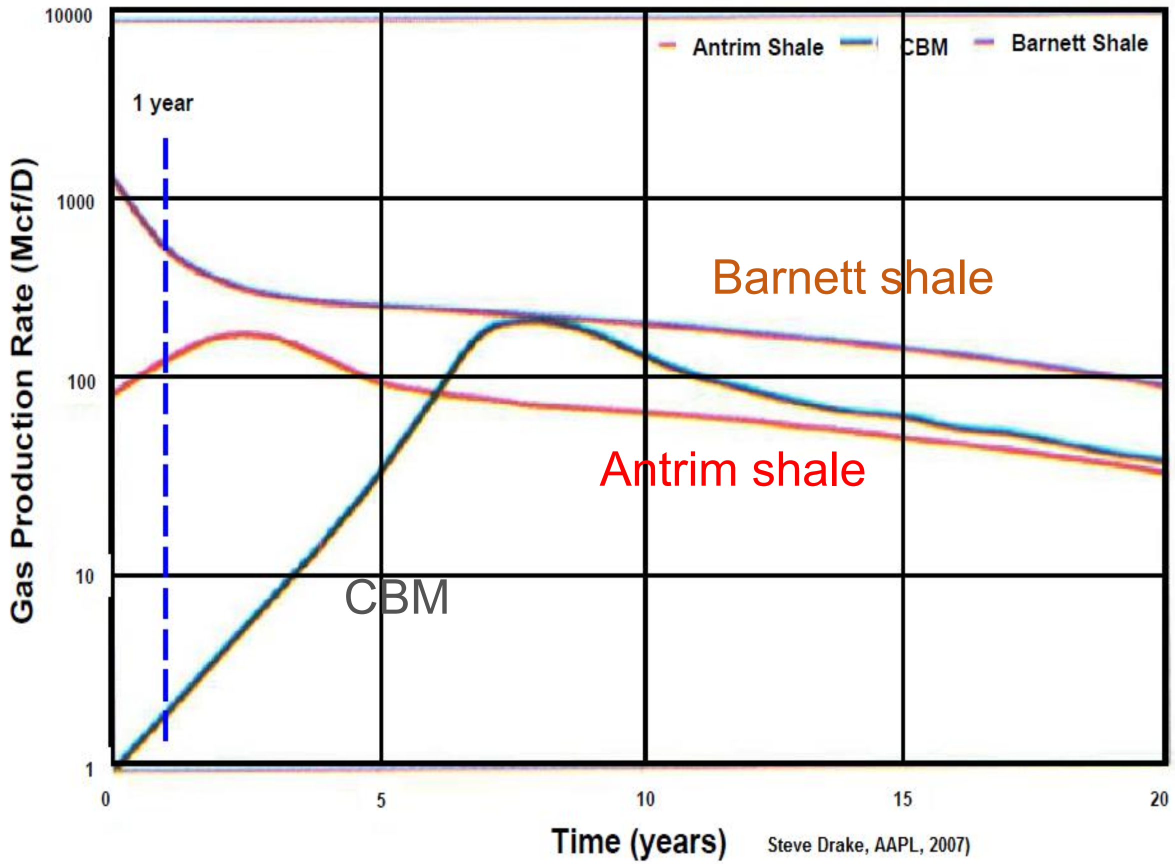
Cumulative production and production rate

$$Q = \alpha \sqrt{t}, \qquad q = \frac{1}{2}\frac{\alpha}{\sqrt{t}}$$

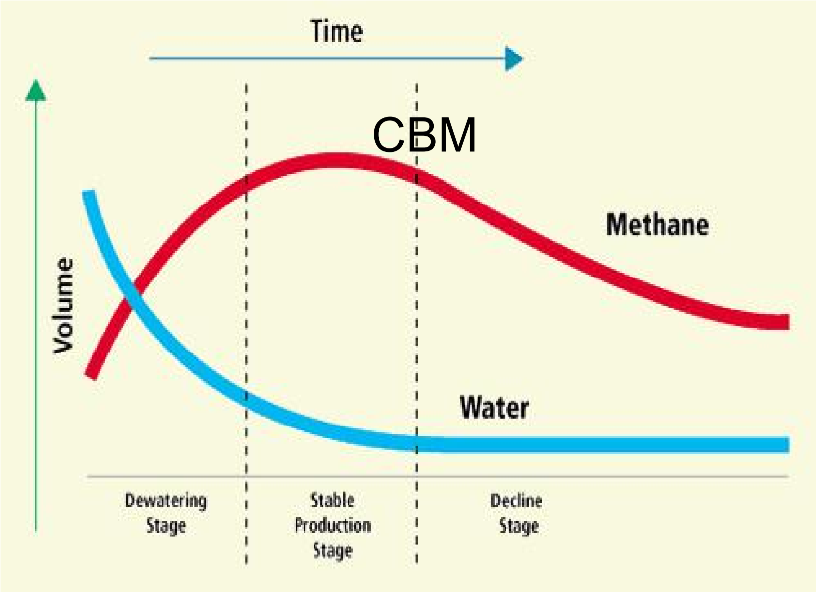
where α depends on

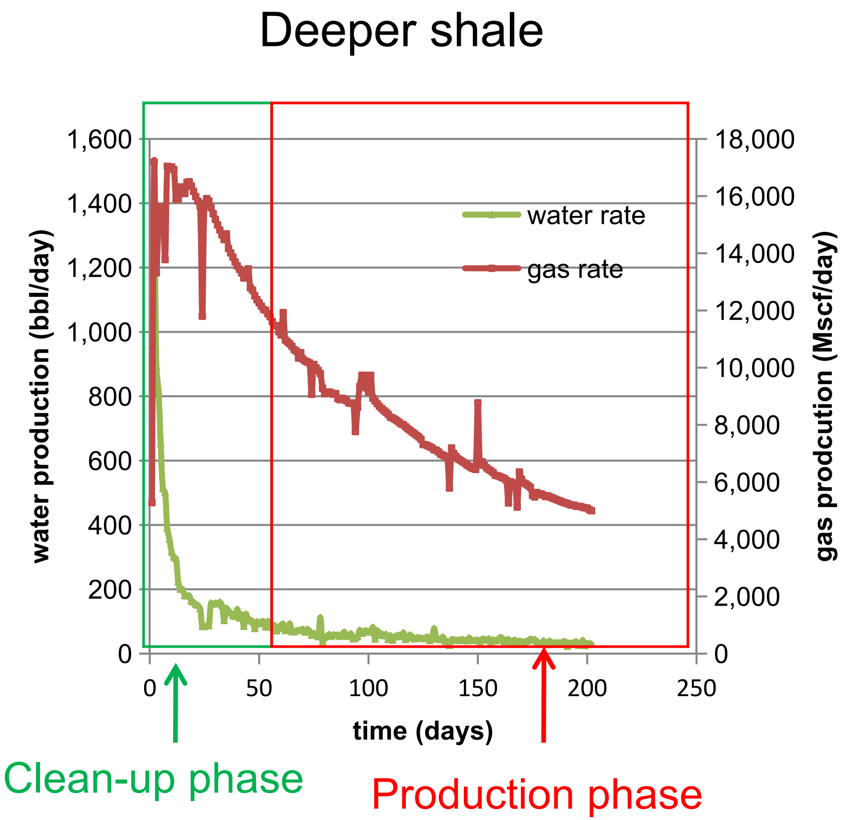
- Pressures (bhfp, pore or reservoir pressure)
- Reservoir quality/ GIP (permeability, porosity)
- Gas properties (viscosity, compressibility, equation of state)
- Productive fracture surface area

Type Curve (Well Performance) for three distinctly different unconventional reservoirs.

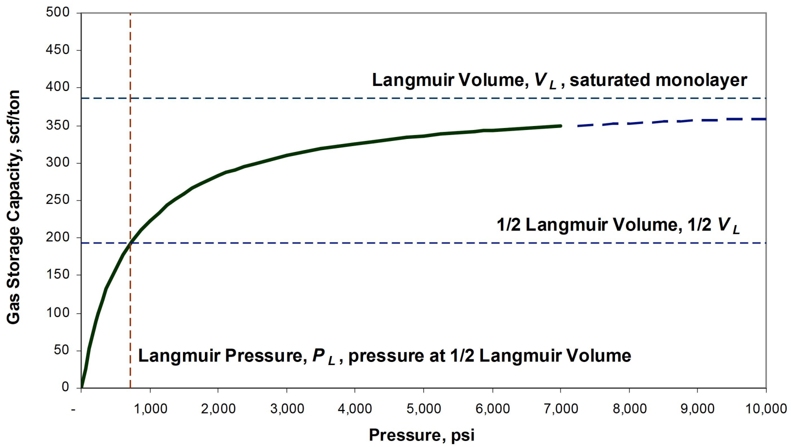


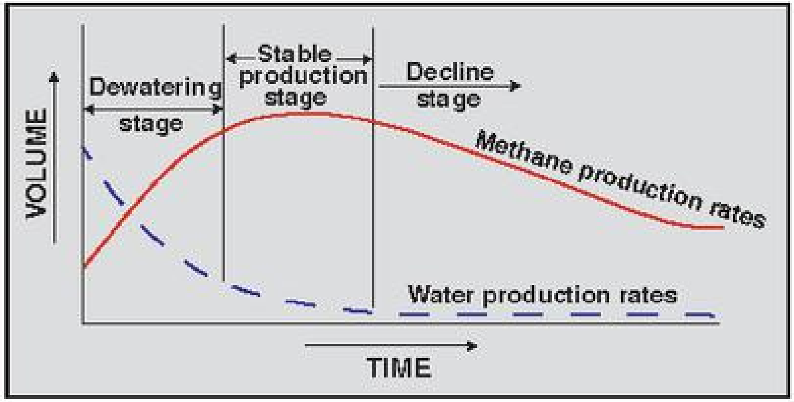
Water and Gas Production



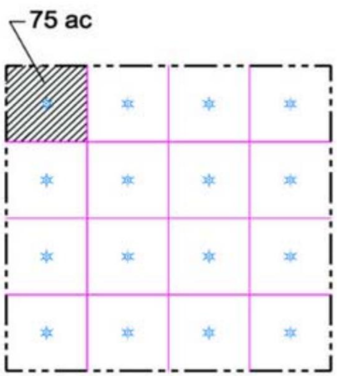


CBM Development



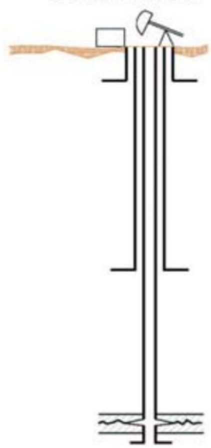


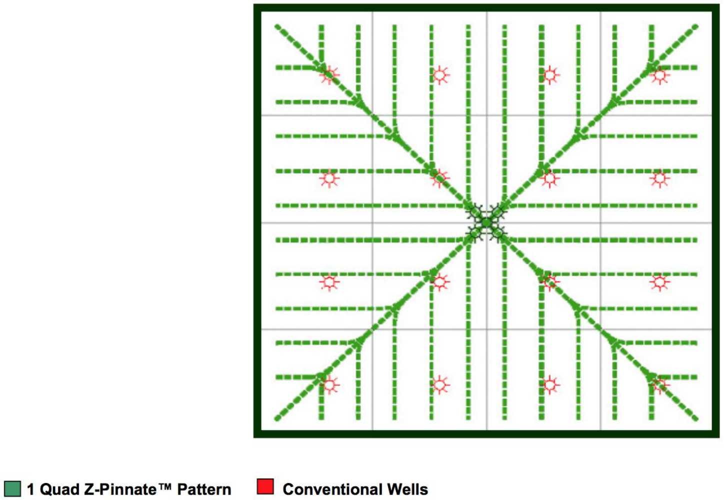
Conventional vs Unconventional Development



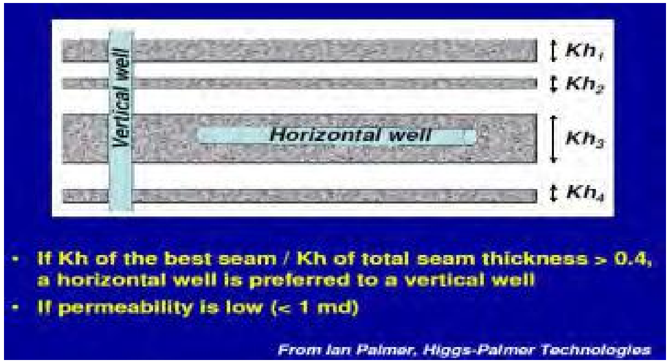
Conventional CBM Development
16 Vertical Well Pattern
1200 acre Drainage

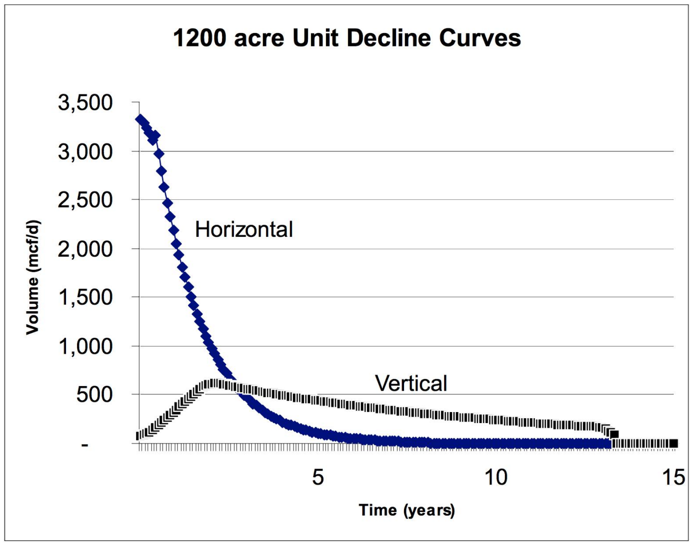
Conventional CBM Well



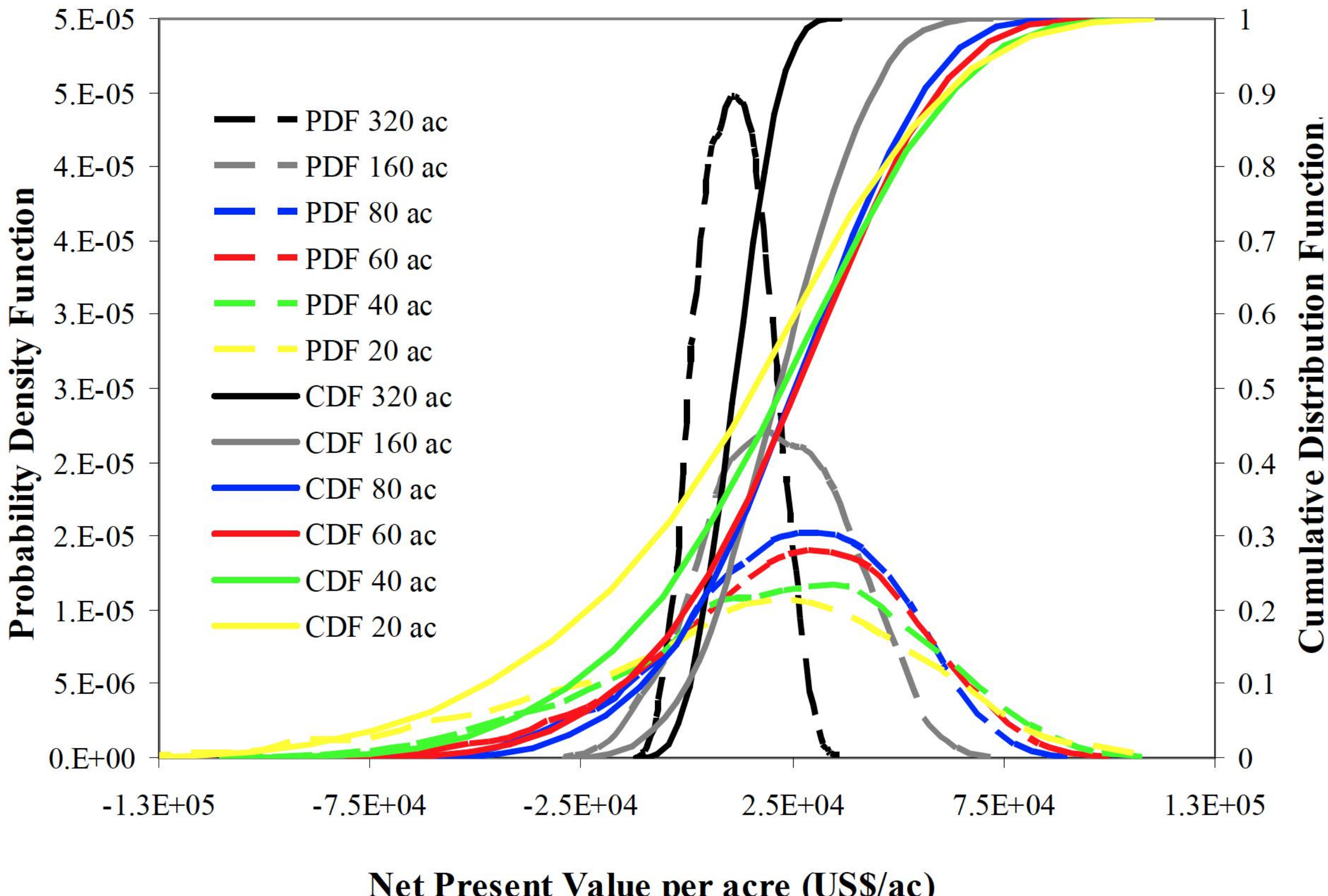


Schoenfeldt et al., CDX Gas, 2004





NpV for 20 years production



P.D. Sinurat, 2010, Texas AM

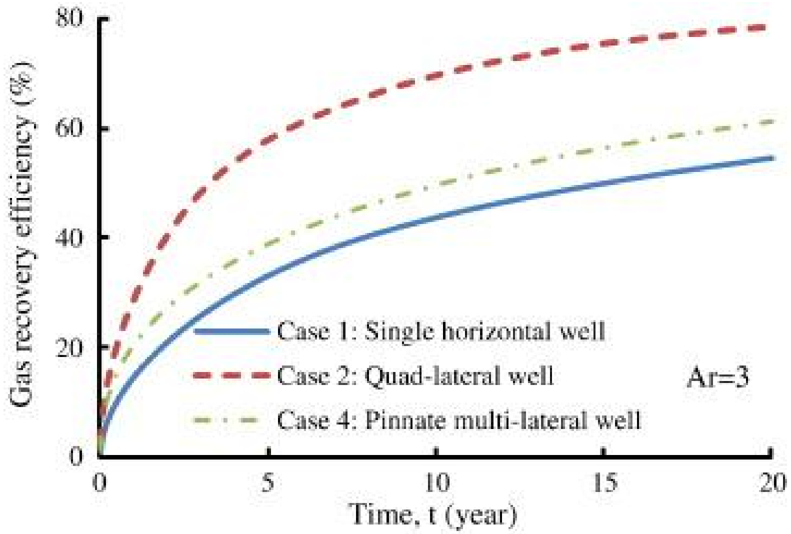
320-acre well-spacing has the lowest NPV

The optimum well-spacing is 40-80 acres

Fig. 4.11 - Comparison of distribution function

CBM Horizontal Well

Country	Basin	Rank	Permeability (mD)	Well Type	Completion	Well Prod.（m³/d）
The U.S.	West Virginia	low	3~4	pinnate horizontal well	Open hole	28000~56000
Australia	Bowen	middle	1~30	V-type	PE slotted screen	15000~2000
China	**Qinshui**	**high**	**<1**	**multilaterals、U-type、L-type**	**Open hole、slotted screen**	**5000**



Ruichen Shen et al., 2015, AAPG

Open Hole Completion

Open Hole Completion

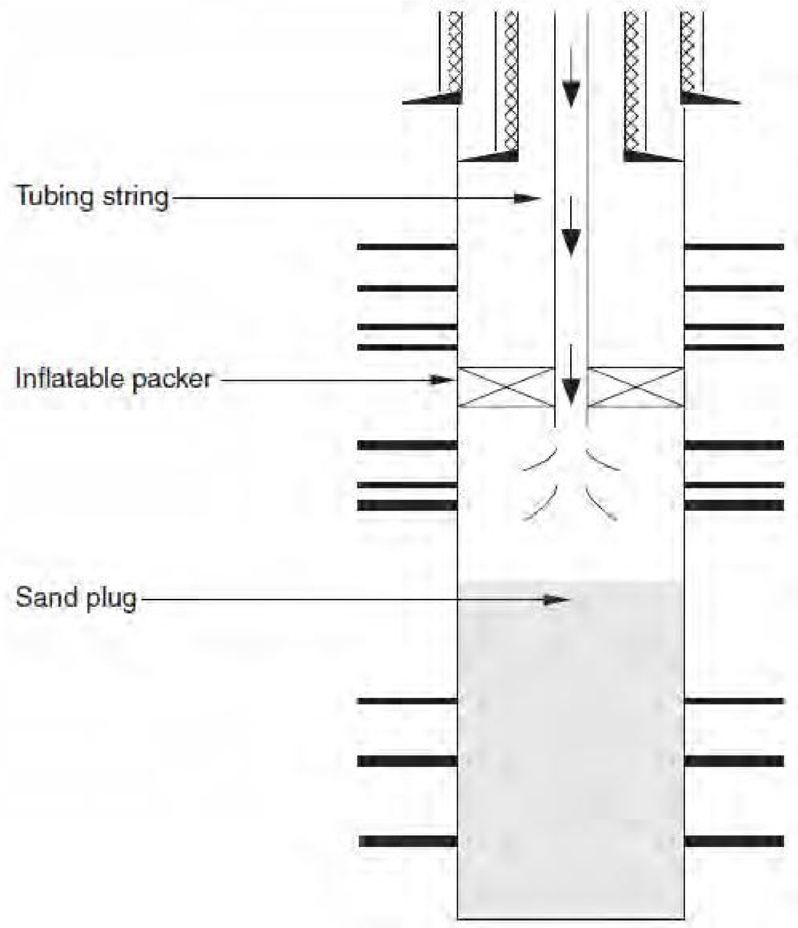
•Simple, cheap & Fracturing not required

•Generally in high permeability and high thickness areas

•No Casing is left to obstruct mining activities

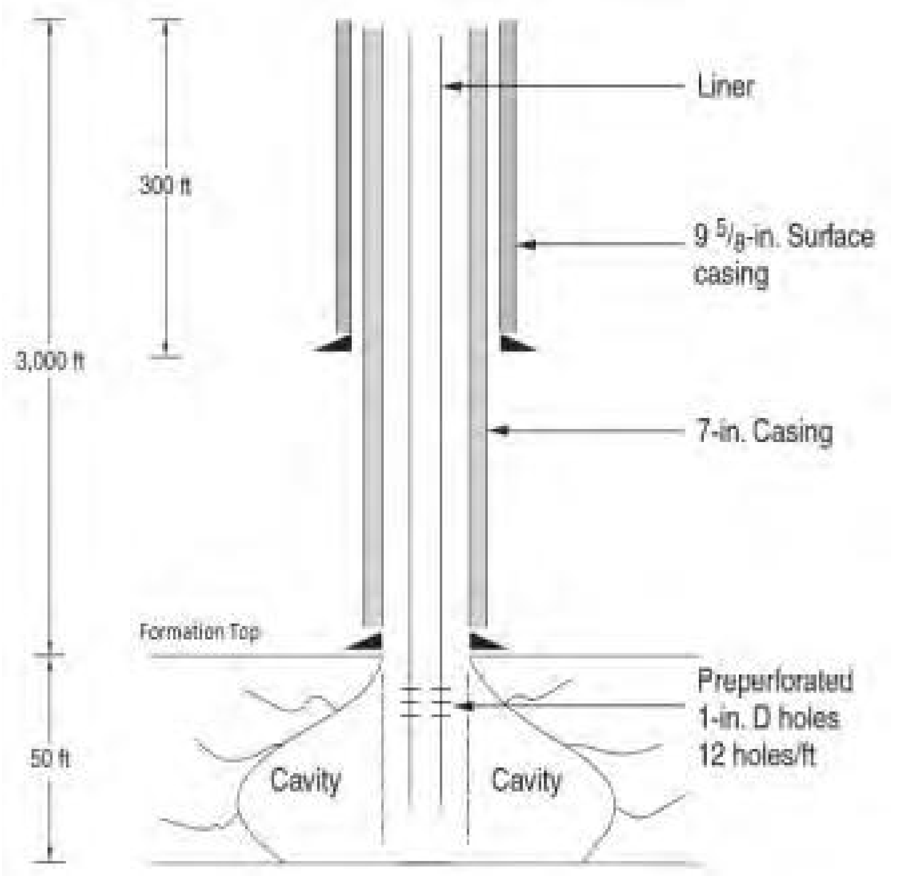
•Cementing does not damage the coals

•Gives unobstructed access to the coal face from the wellbore



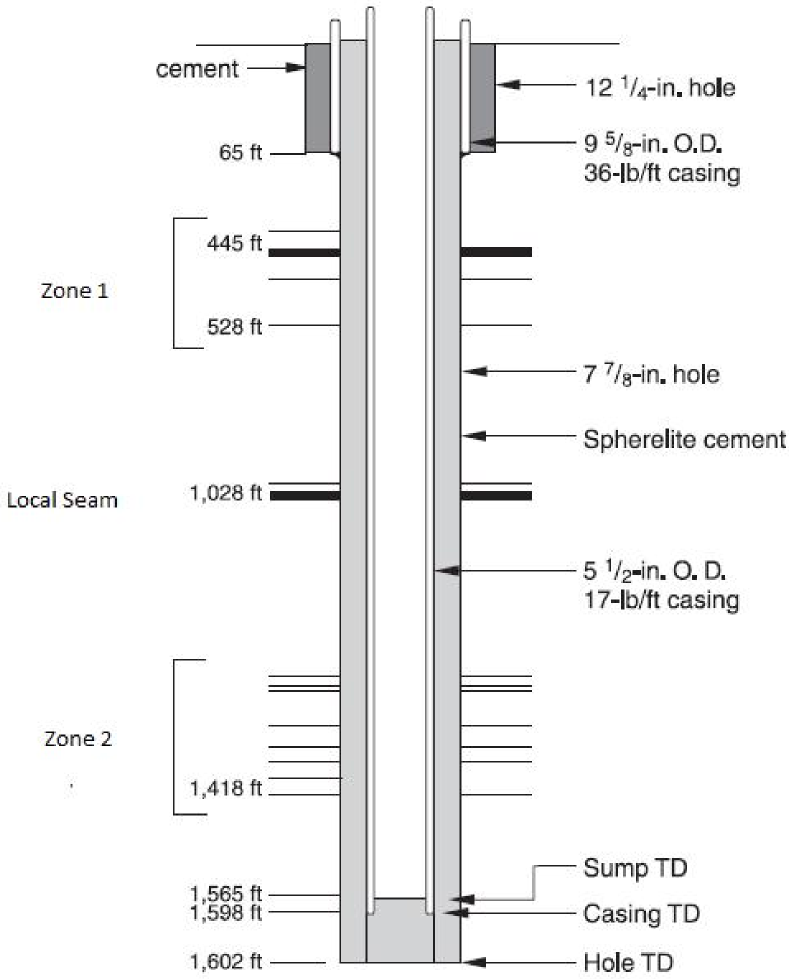
Open Hole Cavitation

- Increases well radius
- Thick seams.
- Good permeability.
- Extensive cleating.
- Ranks of coal beyond the coalification break.
- Low ash content.
- Over pressured zones
- High in-situ stress

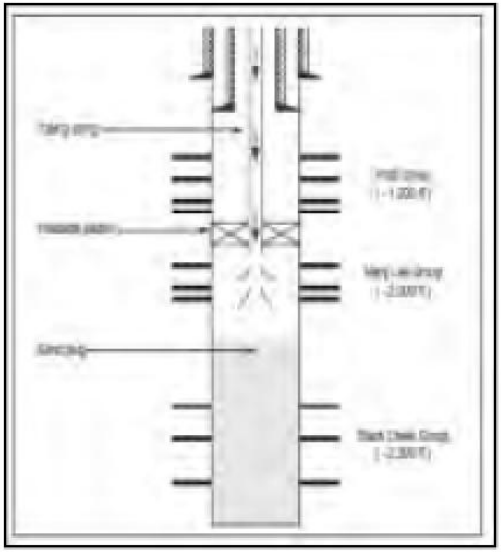


Cased Hole Completion

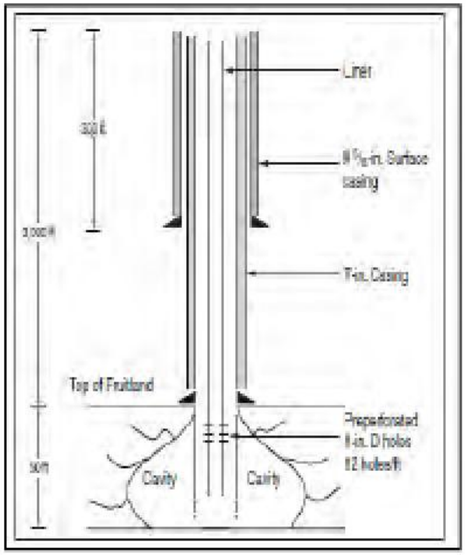
- Multiple seams per well.
- Thin seams of inches to a few feet thick.
- Marginal economics for producing.
- Large volumes of water produced early in the life.
- Normally pressured (some under pressured).
- Depth (1,000–4,500 ft).
- Coal fines.
- Optimum coal rank, hvAb-lvb.
- Good permeability.



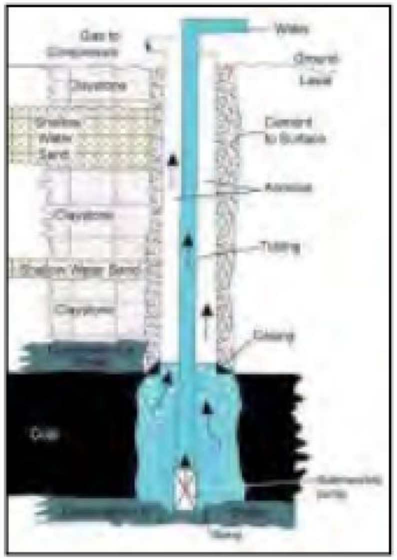
Successful Well Completion Types



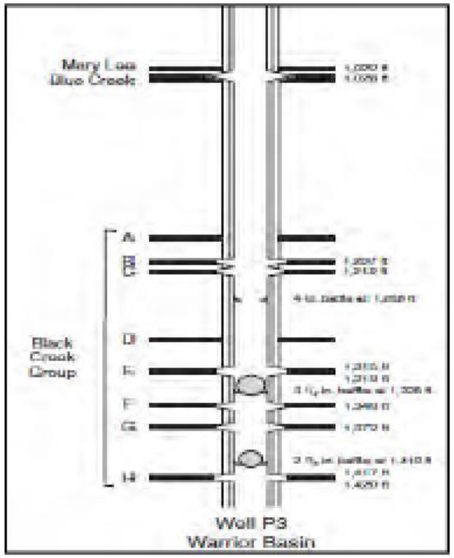
Open-hole (Barefoot)
e.g. Powder River (USA)



Cavitation
e.g. San Juan (USA)

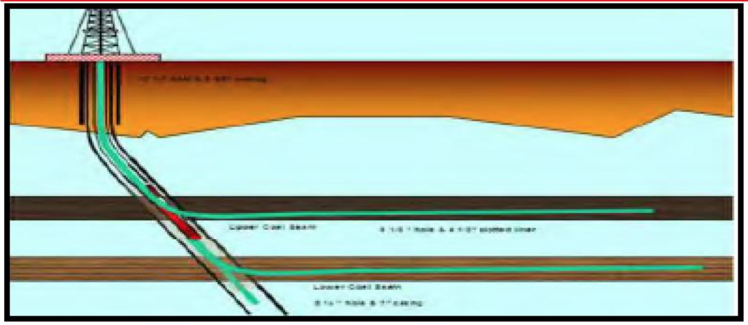


Under-reamed
e.g. Powder River (USA)
Surat Basin (Australia)

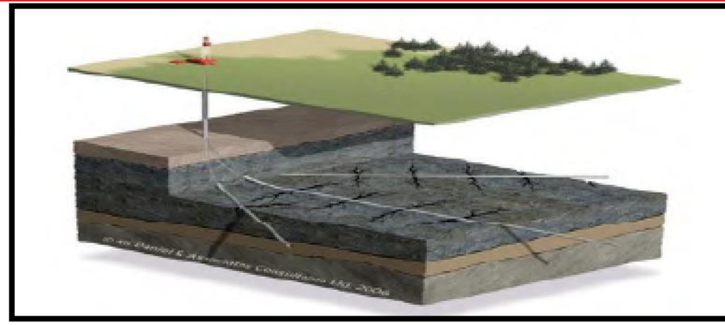


Fracture Stimulation
e.g. San Juan ,Powder River
Quinshui Basin (China)

New Completion

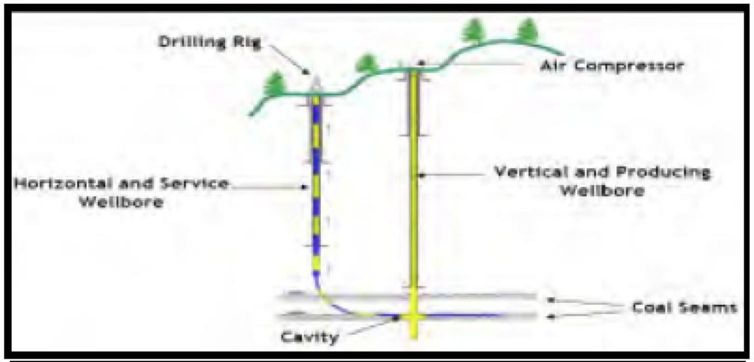


Lateral in Single zone / Multi zone



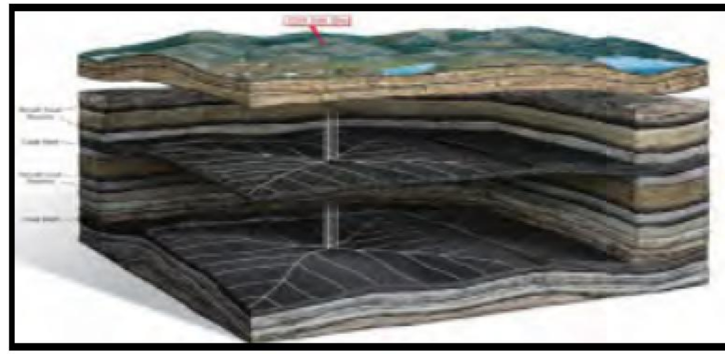
Multilaterals

e.g. Qinshui Basin (China)



In –seam & production from vertical

e.g. Bowen basin (Australia)

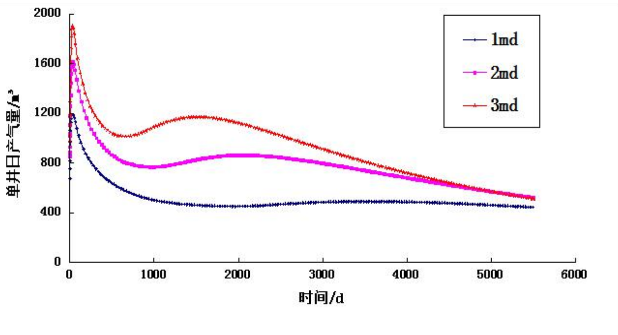


Multilateral – pinnate pattern

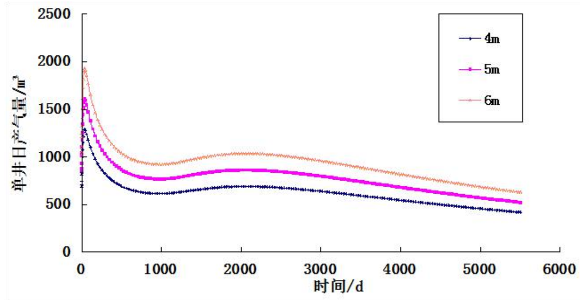
e.g. Bowen basin (Australia)

What Controls the CBM Production-Chinese Case

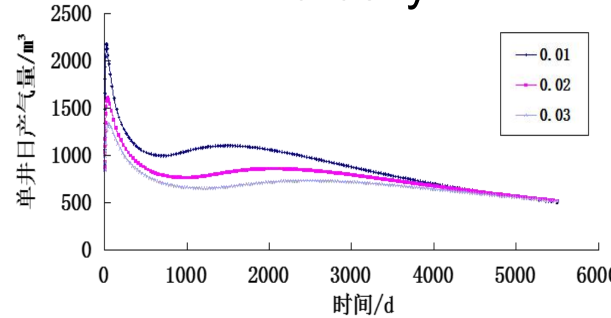
Permeability



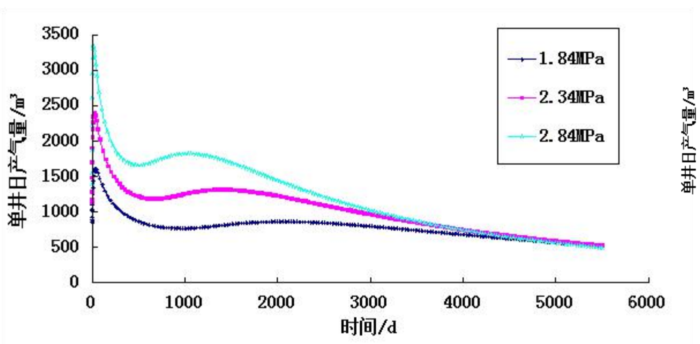
Thickness



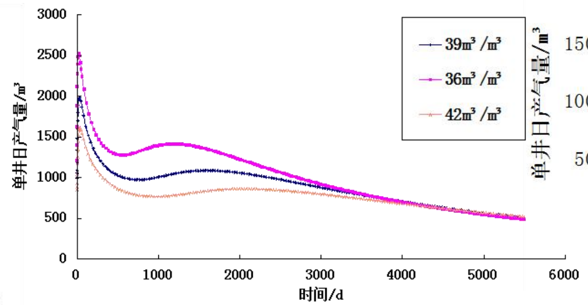
Porosity



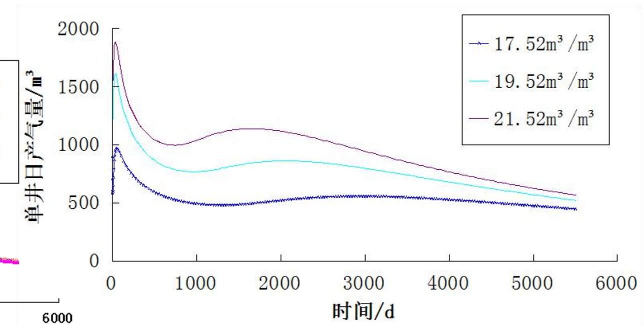
Langmuir pressure



Langmuir volume



Gas content



What Controls the CBM Production-US Case

Table 4.1 - Dataset for base case		
Parameter	**Value**	**Unit**
Thickness	30	*ft*
Fracture cleat spacing	0.042	*ft*
Fracture porosity	0.003	
Fracture permeability	1	*md*
Fracture compressibility	$100E^{-6}$	psi^{-1}
Matrix porosity	0.005	
Matrix permeability	0.1	*md*
Matrix compressibility	$100E^{-6}$	psi^{-1}
Water density.	62.4	lb/ft^3
Water viscosity	0.607	*cp*
Water compressibility	4E-06	*cp*
Coal density	89.5841	lb/ft^3
Langmuir volume	0.23	*gmole/lbm*
Langmuir pressure	725.189	*psi*
Desorption time	10	*Days*
Initial pressure, Fracture	1109.54	*psi*
Initial water saturation, Matrix	0.592	
Initial water saturation, Fracture	0.999	
Reservoir temperature	113	*°F*
Depth	3280	*ft*

P.D. Sinurat, 2010, Texas AM

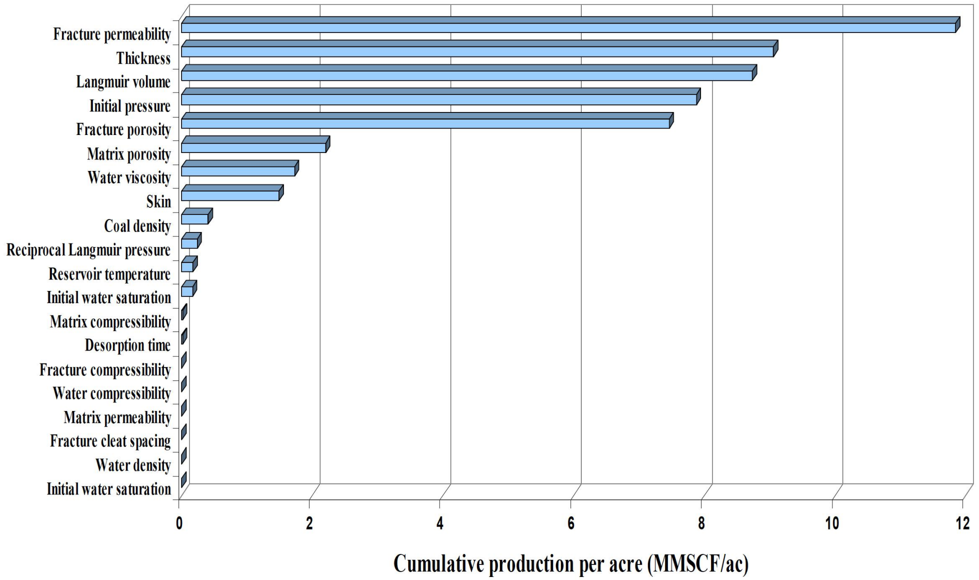
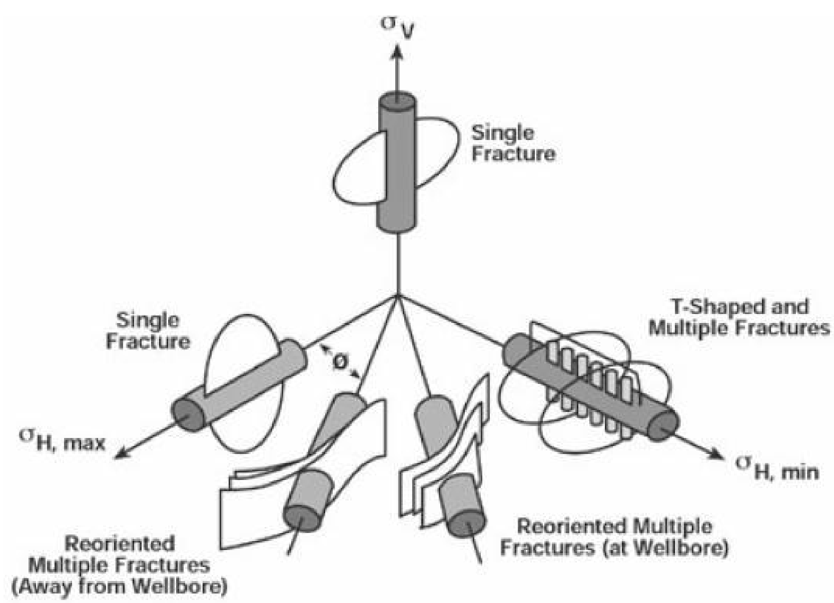
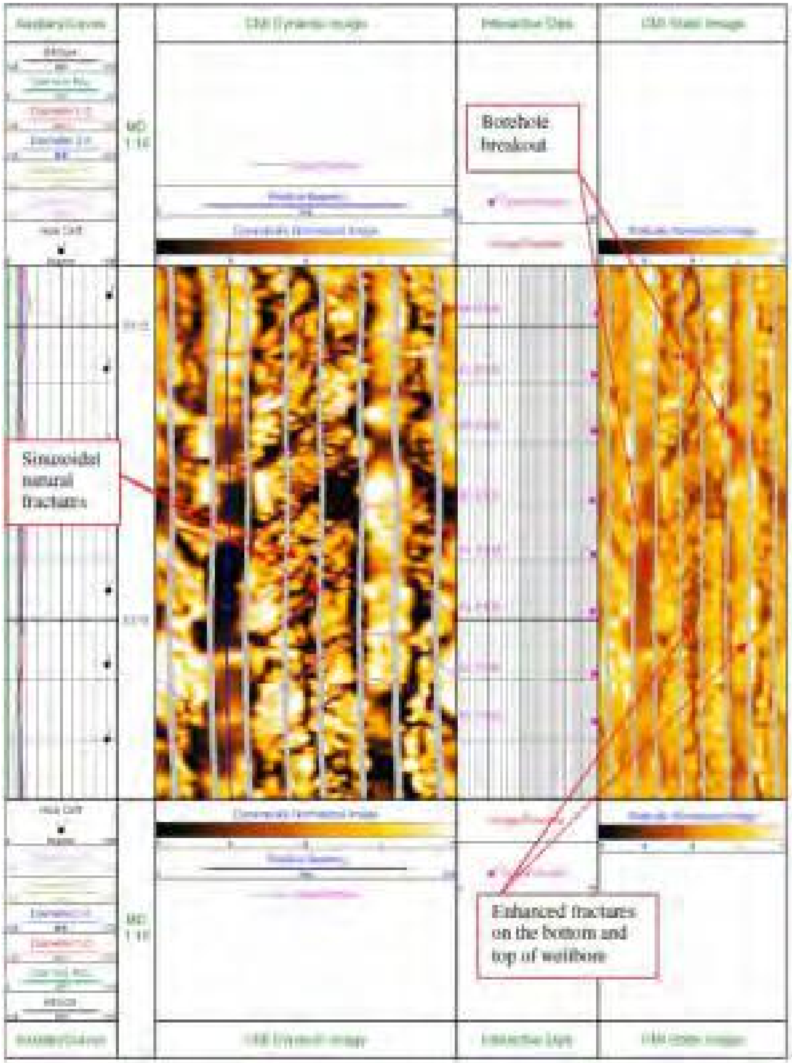


Fig. 4.3 - One-Factor-A-Time sensitivity study result

Well Placement vs Fracture Orientation

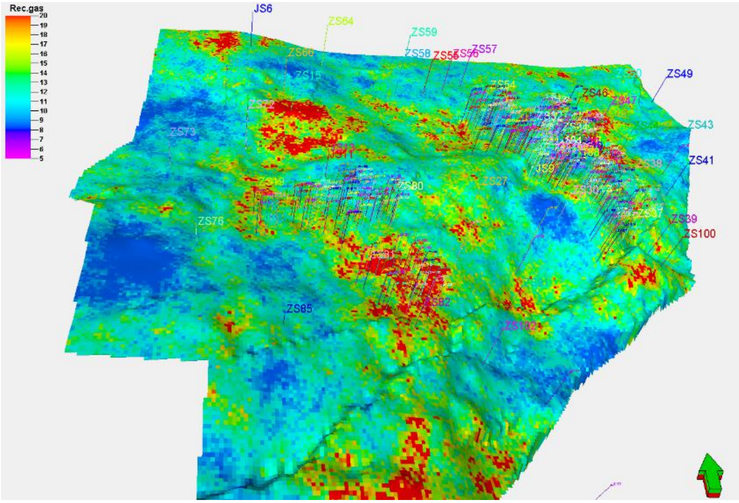
Horizontal well to be drilled in the direction of minimum horizontal stress (minimum permeability), perpendicular to maximum horizontal stress direction.



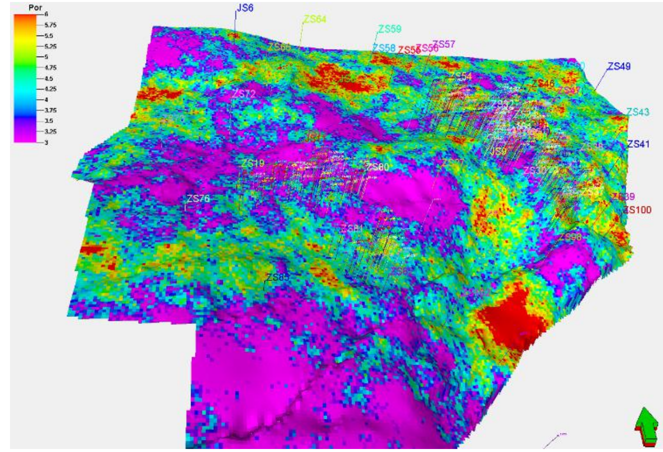


ESSAR ENERGY

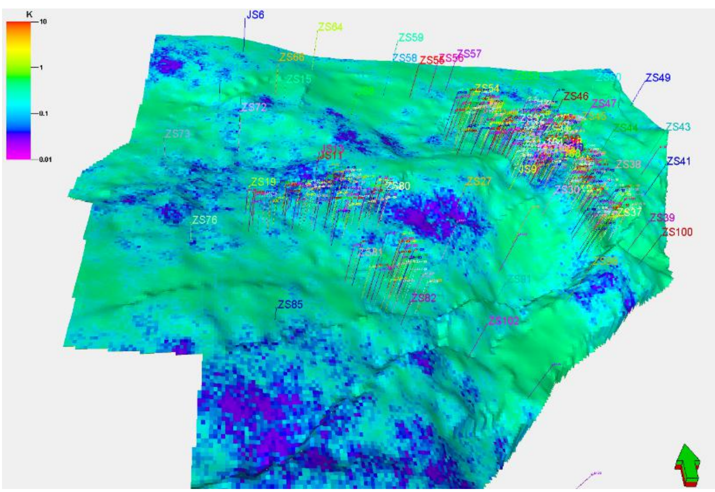
Reservoir Modeling and Simulation for Development



Gas saturation



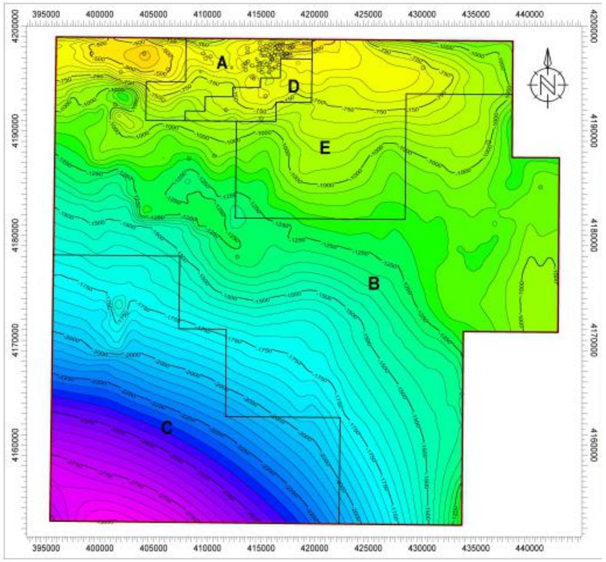
Porosity



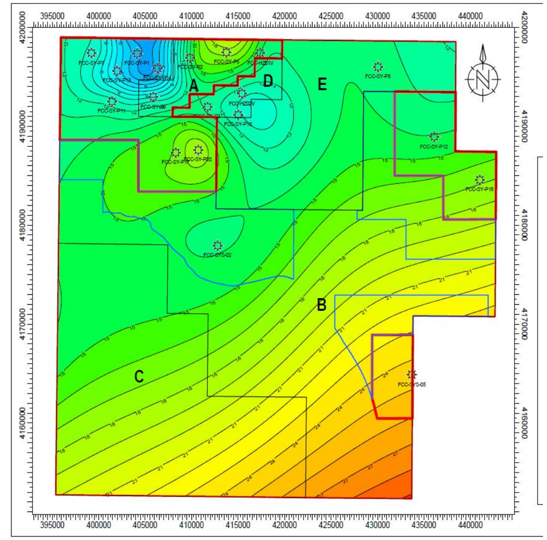
K

Development area:
high gas saturation,
High porosity, high K??

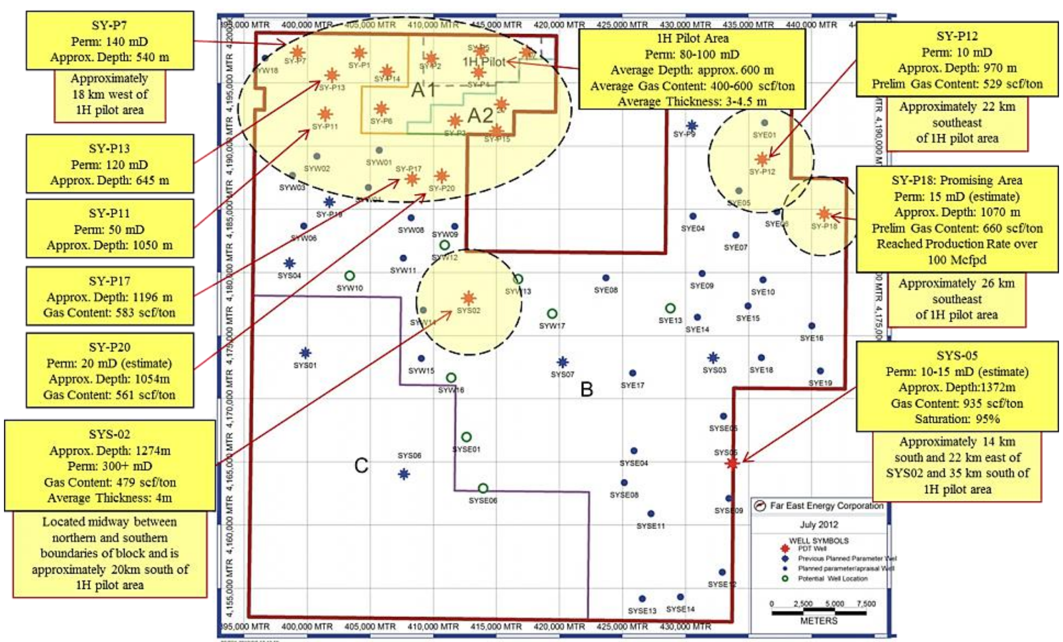
Structure vs Gas Content vs K



Structure

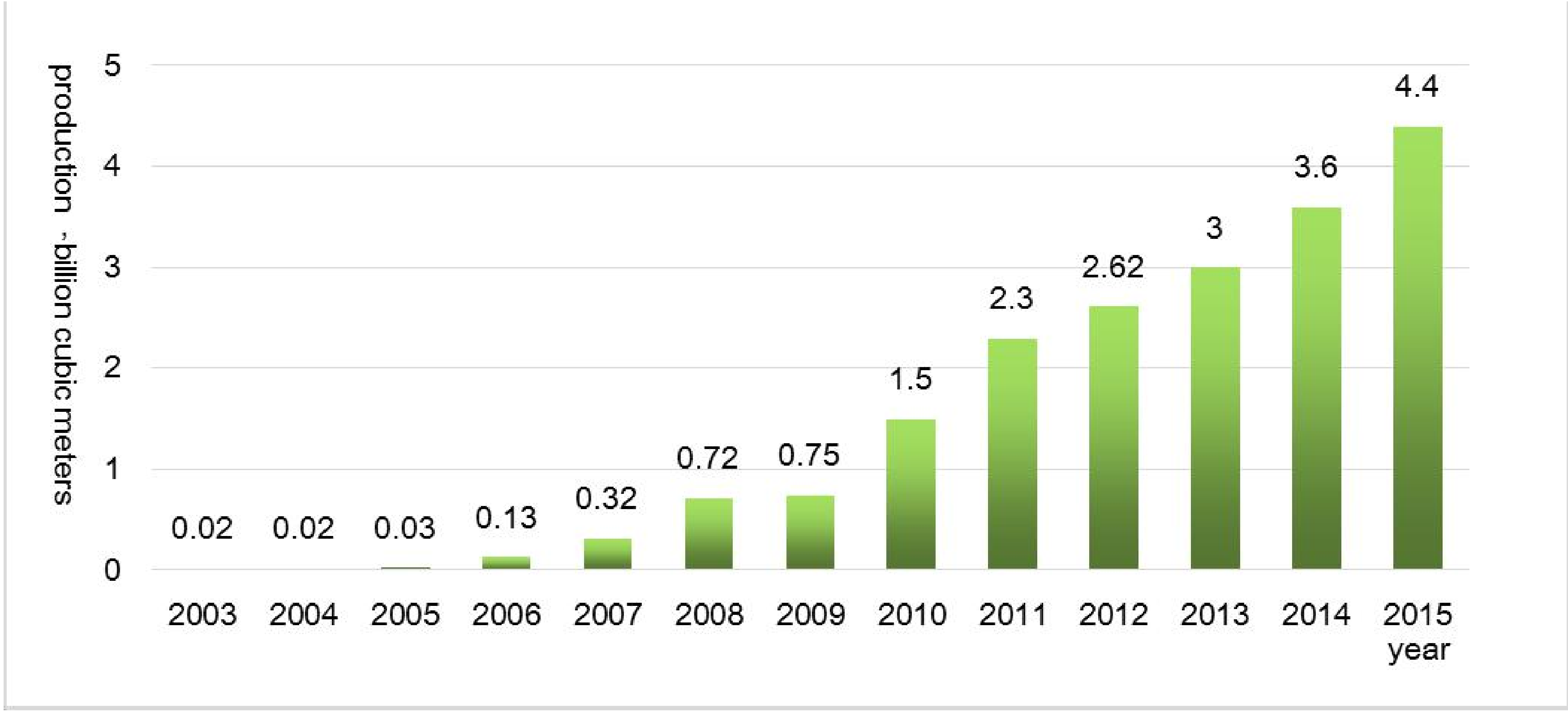


Gas content



What relationship did you find between structure, gas content and permeability?

CBM Production in China

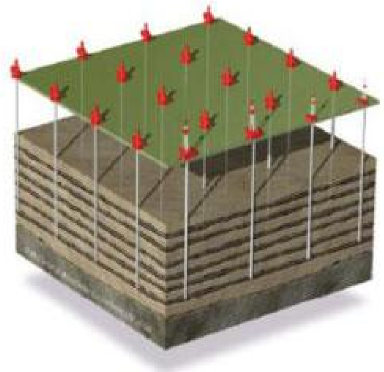


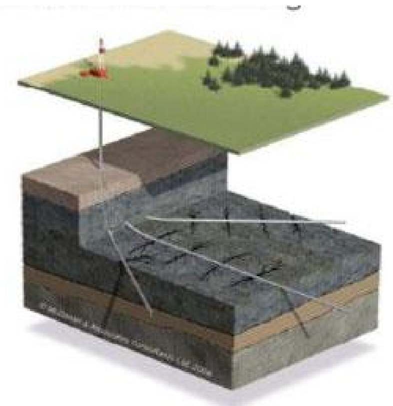
Shale Reservoirs

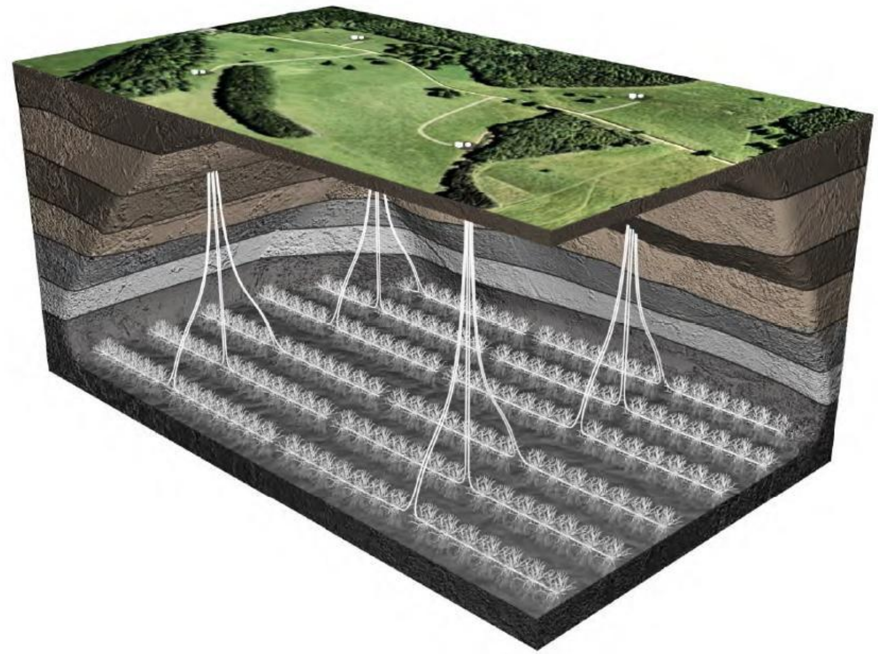
Located on a regional basis
Large area
Extremely low permeability < 0.1 md
Oil and gas are produced in shales and they are the reservoir

Produced by multiple hydraulic fracture treatment of long horizontal wells

Production is typically only for a few years Optimal placement of wells critical
Refracturing is option for increasing production







Stages of Exploration and Development

0 1 2 3 4 5 20

Time (years)

Exploration Tasks

**Stage 1:
Identification of UCG Resource**

Preliminary geological assessment to determine potential for hydrocarbons

**Stage 2:
Early Evaluation Drilling**

Vertical drilling to obtain core samples for reservoir properties along with estimation of resource potential and geographic limits of potential field

**Stage 3:
Pilot Project Drilling**

Early horizontal drilling to evaluate well performance with varying hydraulic fracturing technologies along with continued reservoir testing to determine engineering properties

**Stage 4:
Pilot Production Testing**

Advanced hydraulic fracturing testing and improvements of productivity with reduced expenditure

Pace of development is largely dependent on technical success and market conditions

**Stage 5:
Commercial Development**

↓

Project Reclamation

Key Aspects of Unconventional Play Development

Unconventional Resource Play Strategy is Critical to Success

Understanding the Play

- ➢ **Reservoir Characterization**
- ➢ **Resource Assessment**
- ➢ **Formation Properties & Analogs**

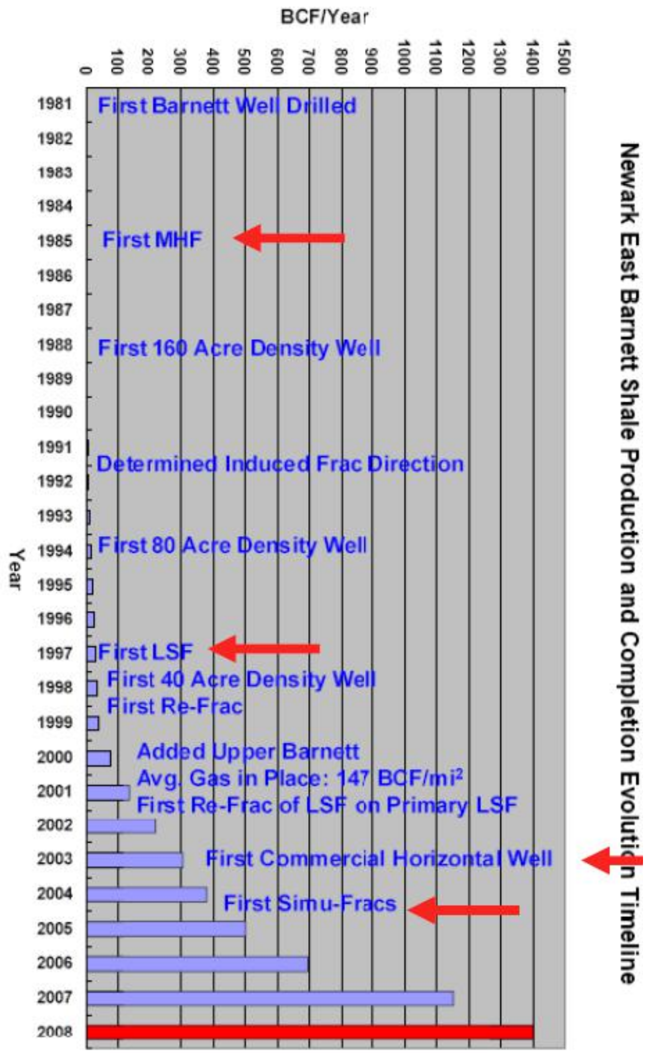
Address The Resource Play Challenges

- ➢ **Which technologies, services or products are most appropriate**
- ➢ **Operational Risk / Cost Assessment**
- ➢ **Field Trials / Pilot**

Build in Efficiency

- ➢ **Scale of operations is usually large**
- ➢ **Remote areas may add significant cost**
- ➢ **Bundling of Services, Concurrent / Continuous Operations**

Evolution of Treatments - Barnett Shale



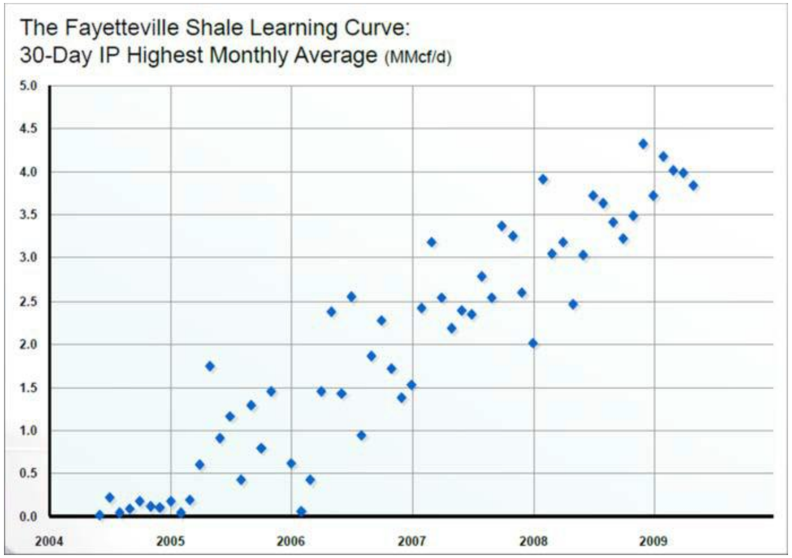
"Progression of shale development has been driven by technology adaptation and innovation in many different shale areas. For example, horizontal wells, multistage fracturing and step-rate increases and slick water fracturing were all tested in the Devonian shale 10 years before being used in the Barnett – the adaptation that made them work in the Barnett was large volume fracs at very high rates."

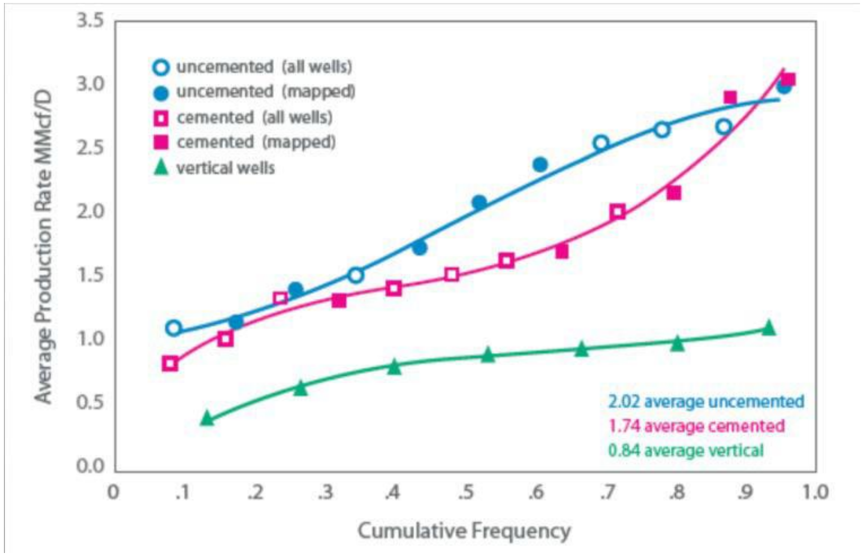
Steinsberger, N., "The Barnett Shale and Evolution of North American Gas Plays," SPE ATW on Unconventional Reservoirs, Barossa Valley, Australia, 2008

Optimization of Reservoir Production

Understanding the Reservoir is Key to Optimizing Production and Reserve Recovery

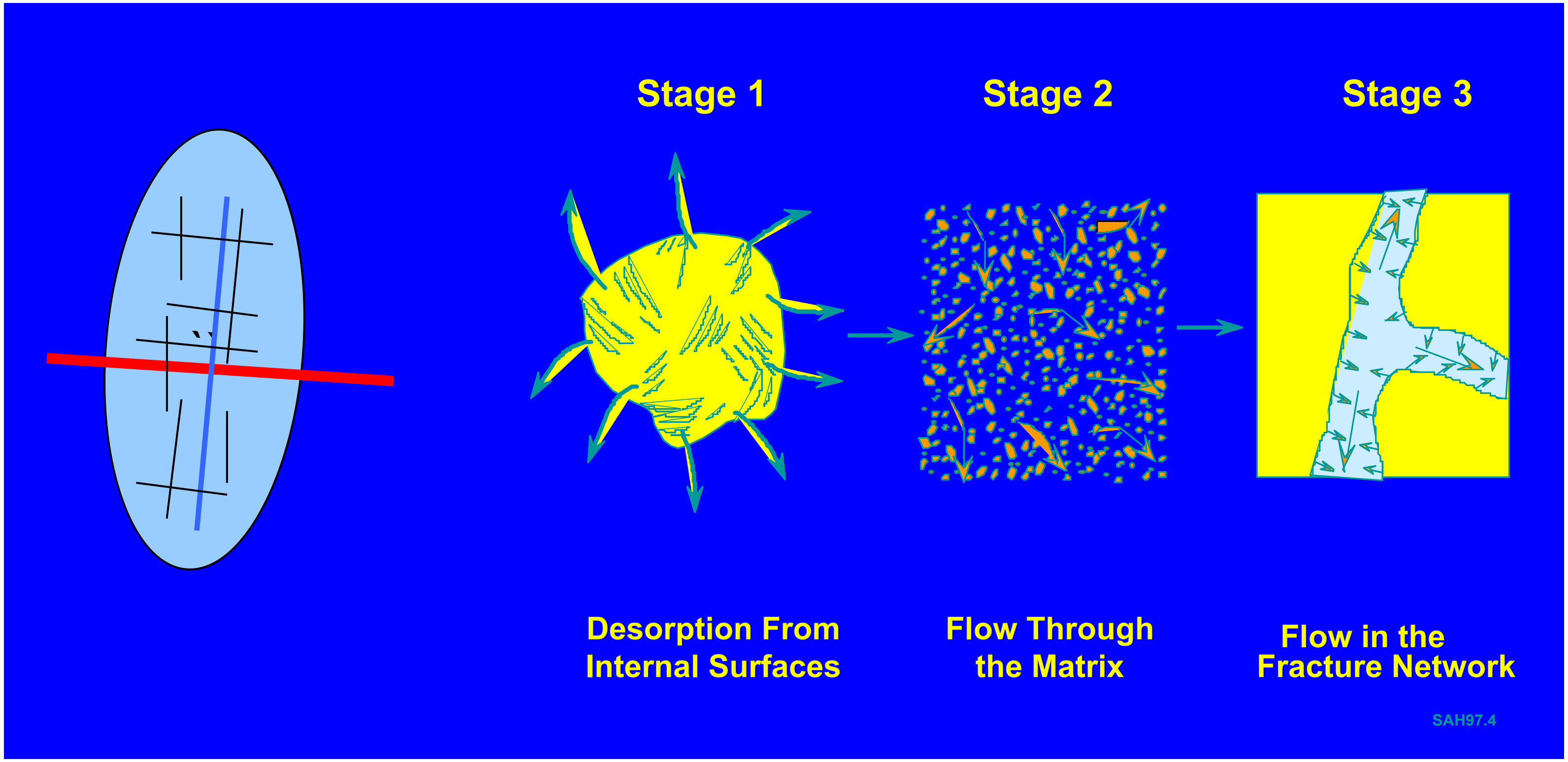
This is achieved through continuous improvements and experimentation in drilling, completion and production techniques





From Southwestern Energy, 2009

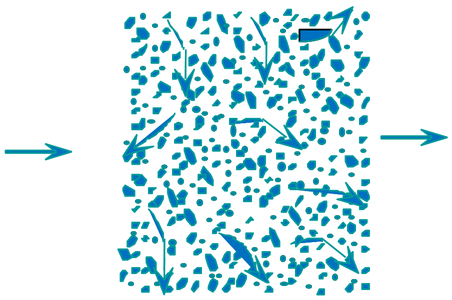
Gas Production Process in Naturally-fractured organic-bearing reservoirs



Triple Porosity Gas Storage

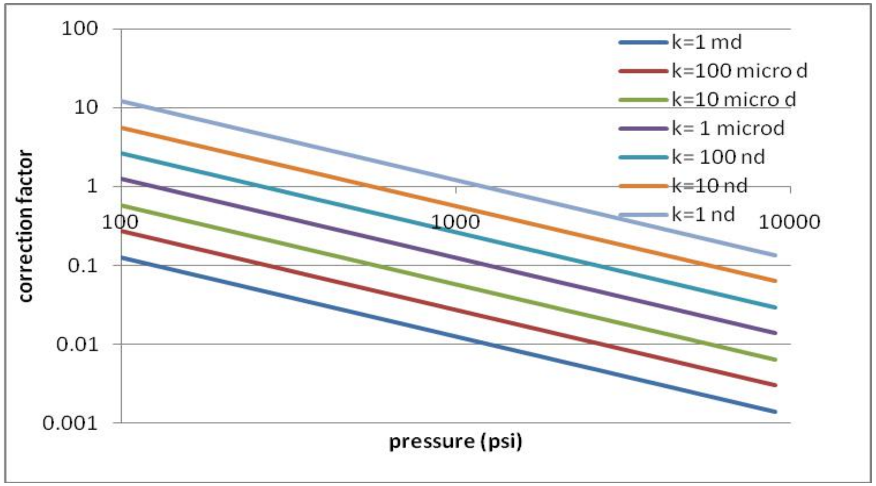
- Micro- (<2 nm) and Meso-Porosity (< 50 nm)
  - Gas Storage by *Adsorption*
  - Mass Transfer by Diffusion
- Macro-Porosity
  - Gas Storage by *Solution and Compression*
  - Mass Transfer by Diffusion and Darcy Flow
- Natural or Induced Fractures
  - Gas Storage by *Solution and Compression*
  - Mass Transfer by Darcy Flow

Flow through the matrix



- permeability: 1nd to 400 nd
- diffusion or
- Darcy flow or
- Modified Darcy flow
    - Klinkenberg effect
- Two-phase flow effects

$$k_g = k_l\left(1 + \frac{b}{\overline{p}}\right)$$



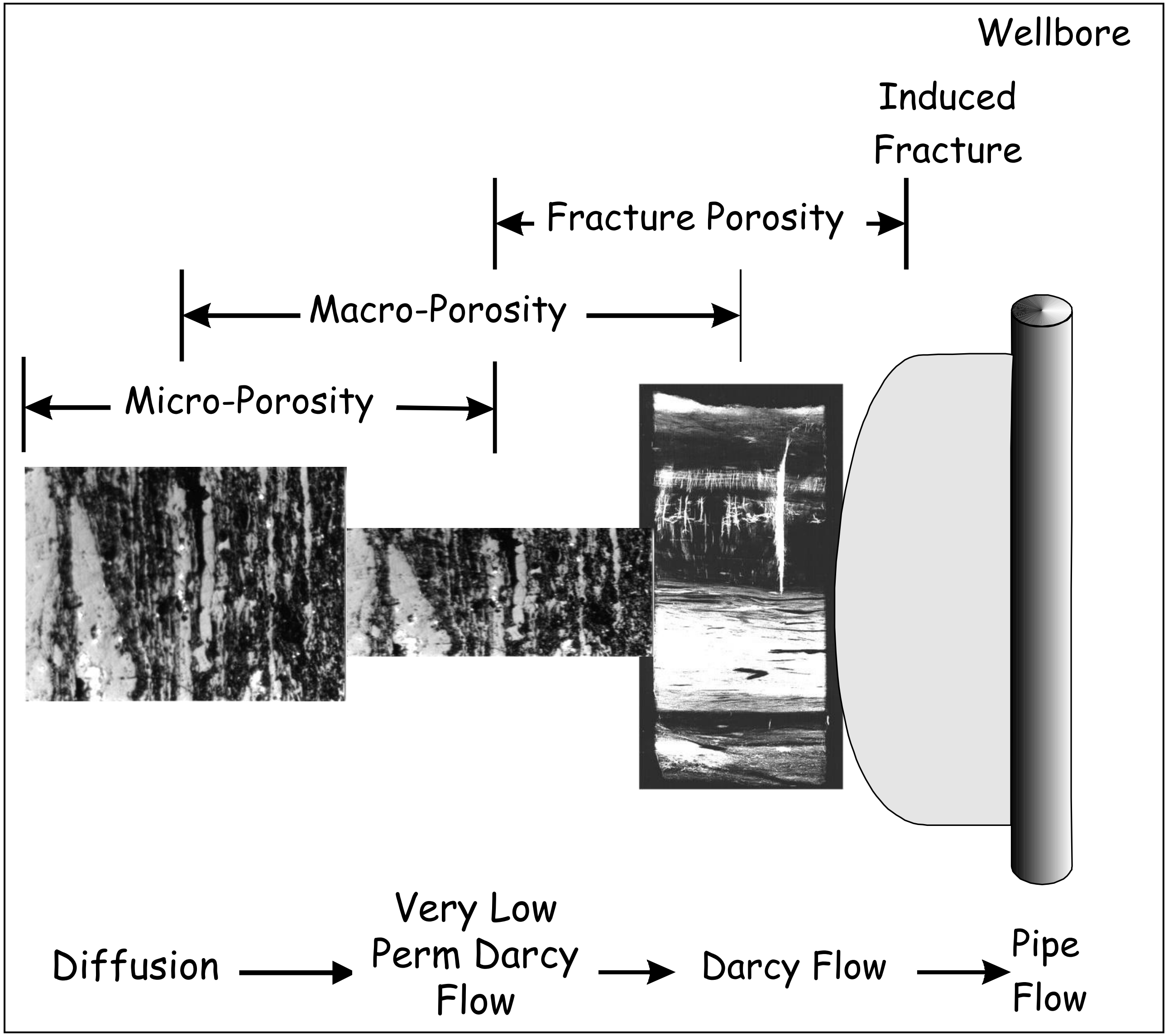
→ changes in pressure or concentration diffuse through the matrix

Diffusion Types

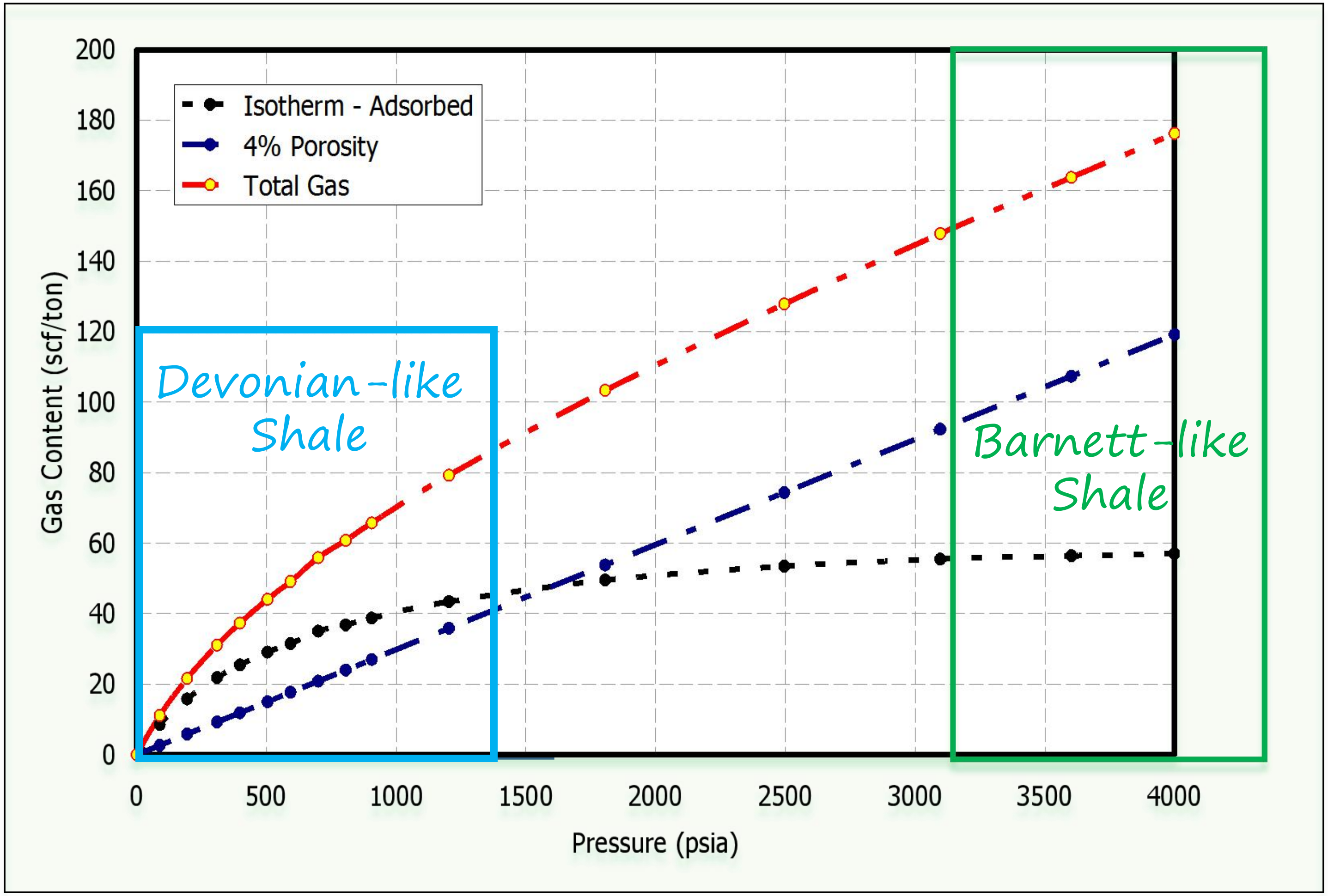
- *Bulk Diffusion*
  - Molecular concentration smoothing
  - Similar to classic iodine spreading experiment
- *Knudsen Diffusion*
  - Dominated by molecule-wall interactions (slip flow)
  - Molecules move from sorbed to free to sorbed phases
- *Surface Diffusion*
  - Molecules remain in sorbed gas phase

Shale Flow Schematic

Shale
Flow
Schematic



Gas In Place



Isotherm - Adsorbed
4% Porosity
Total Gas
Devonian-like Shale
Barnett-like Shale
Gas Content (scf/ton)
Pressure (psia)
200
180
160
140
120
100
80
60
40
20
0
0
500
1000
1500
2000
2500
3000
3500
4000

Shallow Gas Shales
Devonian, Antrim and New Albany

- Shallow, low pressure
- Most gas content is adsorbed on pore walls, about 20%-30% as free gas in pores
- Desorbtion is a major production process
- Matrix permeability is very low, ~0.1 nD.: non-Darcy effects are likely to be important
- Substantial open natural fracture system, closely-spaced, with large surface area and possibly initially water-saturated.

Deeper Gas Shales
Barnett,……, Haynesville,….

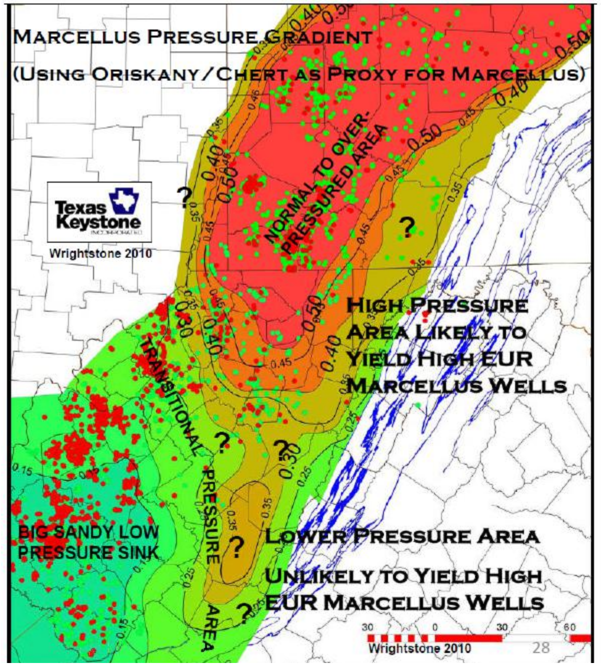
- Higher pressure
- Most gas content is stored as free gas in pores, less than 50% adsorbed on pore walls,
- Desorbtion is a minor production process except at late time.
- Matrix permeability is low, ~100 nD.
- Substantial natural fracture system, initially mineralized.

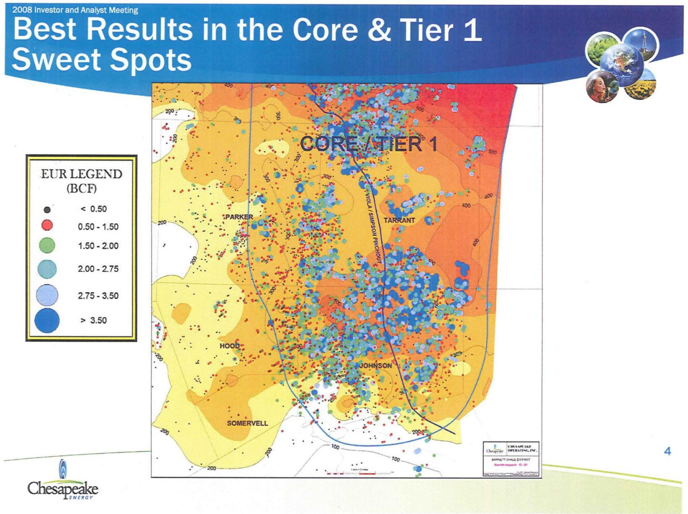
Sweet Spots – Best Production Rates

Mapping a "sweet spot" in a shale play reduces the risk of economic failure.

<u>Critical Variables?</u>

- Pore Pressure
- Gas in Place
- TOC
- Maturation
- Depth of Burial
- Natural Fractures
- Shale Thickness
- Pore or Reservoir Pressure
- porosity
- permeability
- texture
- Structures





What controls shale gas production?

Fundamental

- Deposition/burial history
- diagenesis
- Kerogen type
- mineralogy
- Uplift
- Structural evolution
- hydrocarbon expulsion, retention
- Geomechanics

- Rock-fluid interactions

→

Indirect determinants

- maturity, Ro
- TOC (current and original)
- depth
- pressure gradient
- play thickness
- natural fractures
- water saturation

Drilling, Completion and Stimulation

Production Strategy

→

Direct determinants

- matrix permeability
- matrix porosity
- reservoir pressure
- reservoir temperature
- adsorption parameters: C1, P1

- productive fracture surface area
- fracture spacing
- drawdown

→

productivity

Ideas of What to Look For In a Gas Shale?

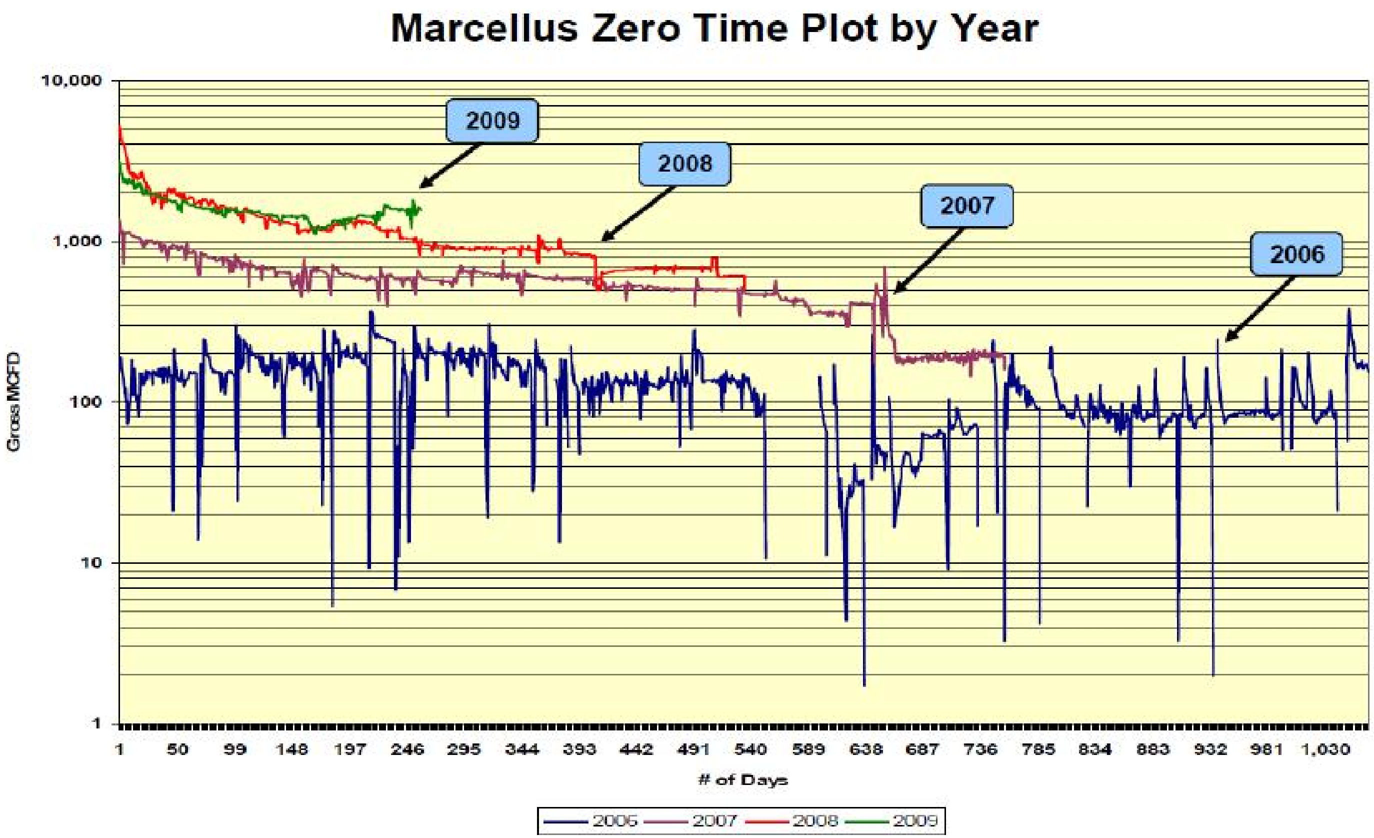
Characteristic	Core Producing Area Range	Minimum for Development	Importance
TOC	3 to >10	>0.5	High
% Silica and/or calcite	>40%?	>25%	Mod/High
Maturity, Vitrinite Reflection, %	1.0 to >2, >1.4 for dry gas	1.4	High
Shale thickness, ft	100 to >1000	>>100 ft	High
Gas in Place, bcf/sq mile	30 to 350	>25	High
Matrix Permeability, md	E-4 to 0.001 md	>0.00005 md	Low
Matrix Porosity (effective)	<2 TO >8%	>4%	High
Depth of pay	400 to 17000	3000 to 12000?	Mod/High
Modulus of Elasticity	3MM to >9MM	Depends on frac barriers	High
Nat. Frac Presence	Yes, open during production	Same	High
Boundaries for Frac	Yes	Absence requires special fracs	Mod/High
Gas Content scf/ton	<30 to >300	>80	High
Gas % in pore	>50%	>30%	High
Gas % adsorbed	<50%	<70%	Moderate
Typical prod rates, scf/d	0.3 to >5 mmscf/d	1.5 to >2MM	Highest
Water saturation	0.1 to <0.35	<0.25	High
Oil Saturation	Low	<0.1	High
Horizontal well length, ft	500 to >4000 ft	>1500 ft	High
Horiz direction rel to frac dir.	Transverse	Between 60 and 135^o	High
Fracture needs	Rubblize the zone	Rubblize the zone	High
Dewatering (frac cleanup) Time	0.1 to 1 months	0.1 to 2 months	Moderate
Decline Rates	50% 1st yr	65% 1st yr	Mod/High
Est. Ultimate Recovery, EUR	>1 to 3 bcf	1 to 2 bcf	Moderate

Technologies That Made a Difference

- **Slickwater Fracturing** using 1 to 3 or more million gallons of water – with friction reducer (less polymer damage, increased penetration and surface area)
- **Horizontal Wells** replacing vertical wells for production. Newer horizontals with over 3000 m reach - either cased and cemented or open-hole and **isolated** with packers
- **Multi-Stage Fracturing Treatments:** Numerous (10 to 40) fracture stages per well develop very large fracture-to-formation contact areas and higher gas rates

Impact of Technology on Production

Marcellus Average Normalized Production Data by Drilling Program Year



Frac Development

Range Marcellus Shale Fracs

Bigger Jobs and Lower Costs – Better Well Results

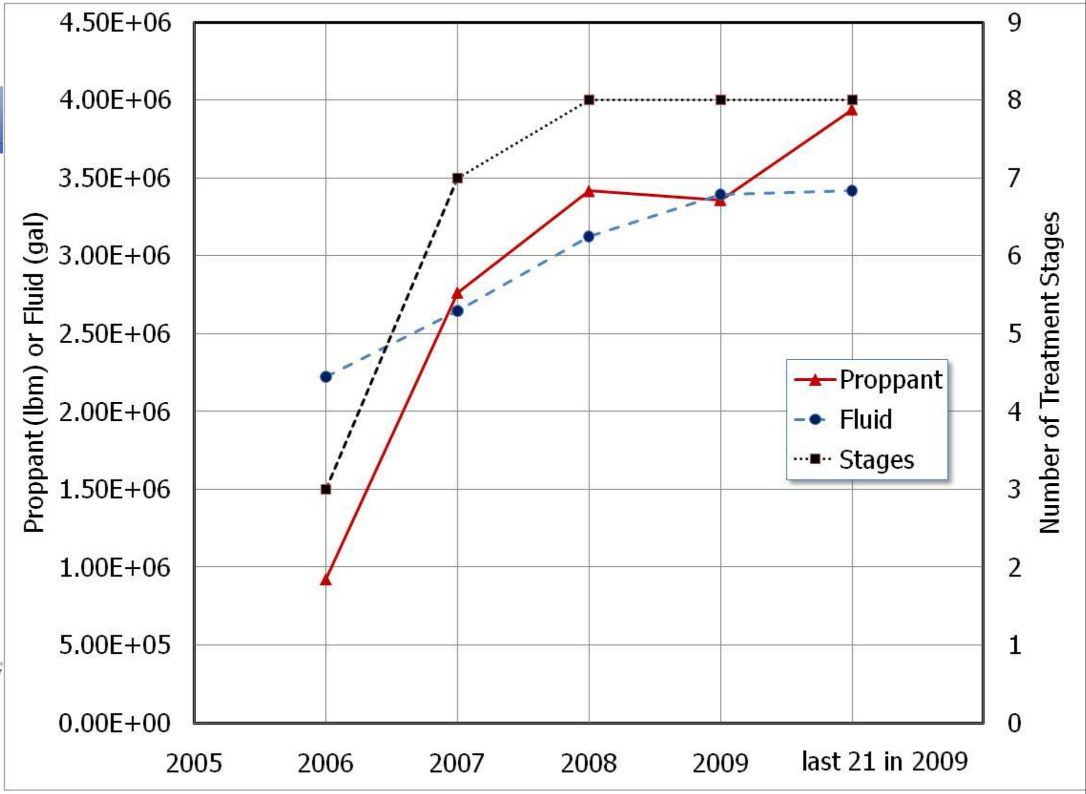
	Proppant, lbs.	Fluid, gallons	Stages
2006	923,000	2,225,000	3
2007	2,765,000	2,646,000	7
2008	3,418,000	3,127,000	8
2009	3,361,000	3,397,000	8
2009 – Last 21	3,943,000	3,419,000	8

Recycling Almost All Of Our Water – Better Environmental Results

Experimenting With Longer Laterals and More Stages

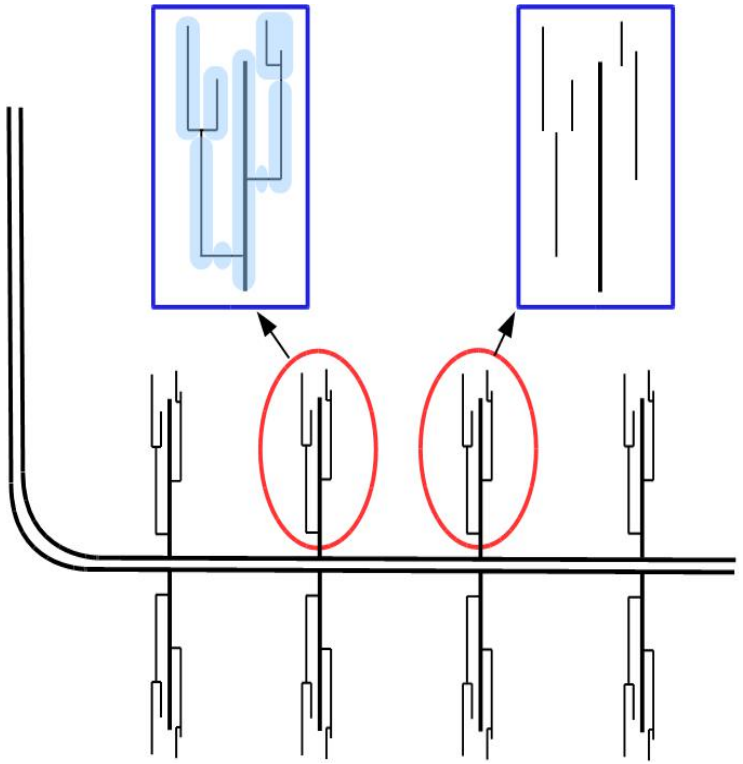
Range Resources

Developing Unconventional Gas - East | October 19, 2009 | 17



How much surface area do we create?

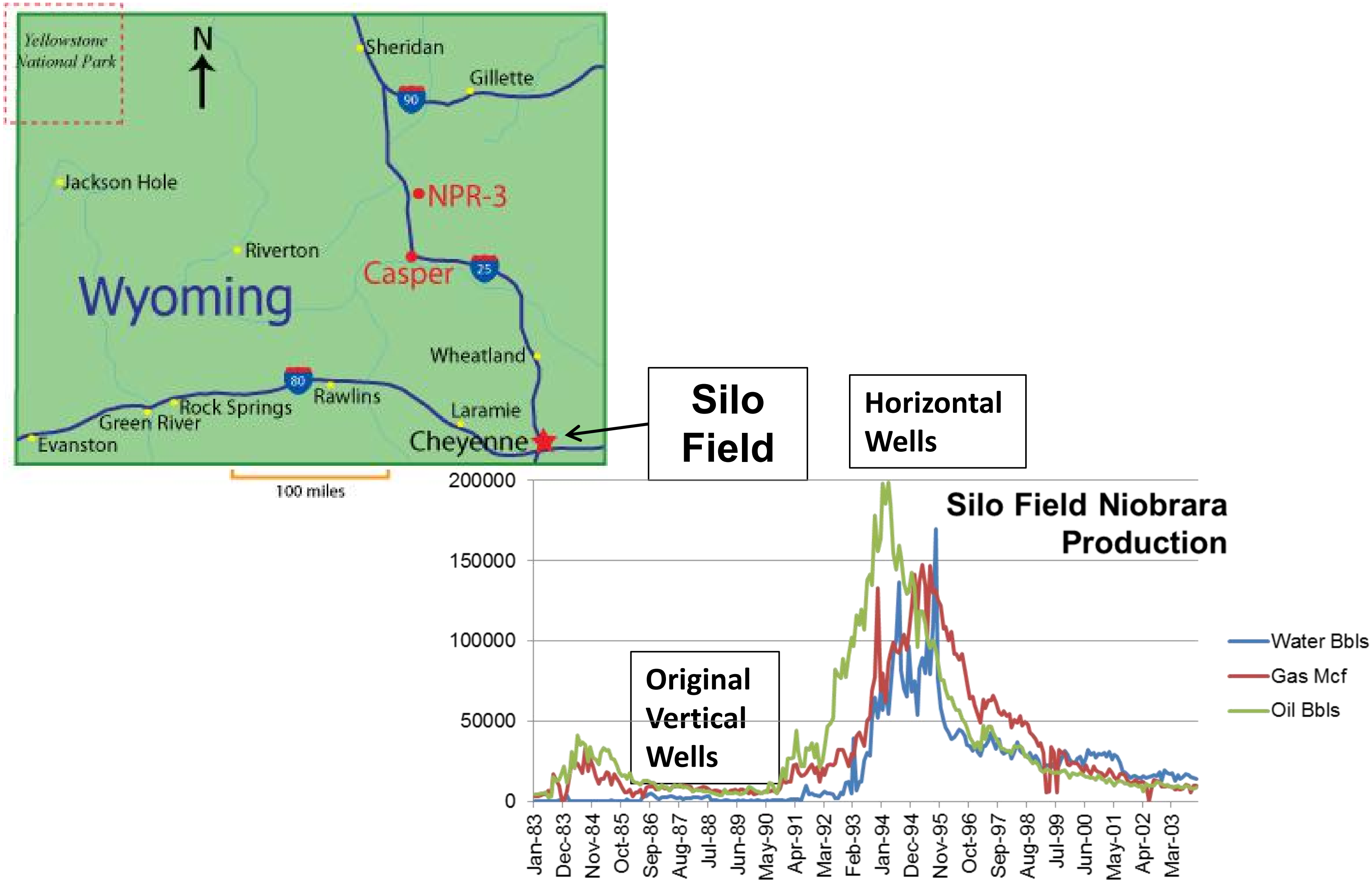
- Fracture model: network of "mineralized" natural fractures opened up during pumping and filled with frac fluid
- Frac width governed by stresses, fluid pressure, frac toughness, "leakoff", pump rate.
- Mass balance
  - Liquid: Frac surface area ~ 100m sq ft
  - Proppant: Propped frac surface area ~ 2-3 m sq ft



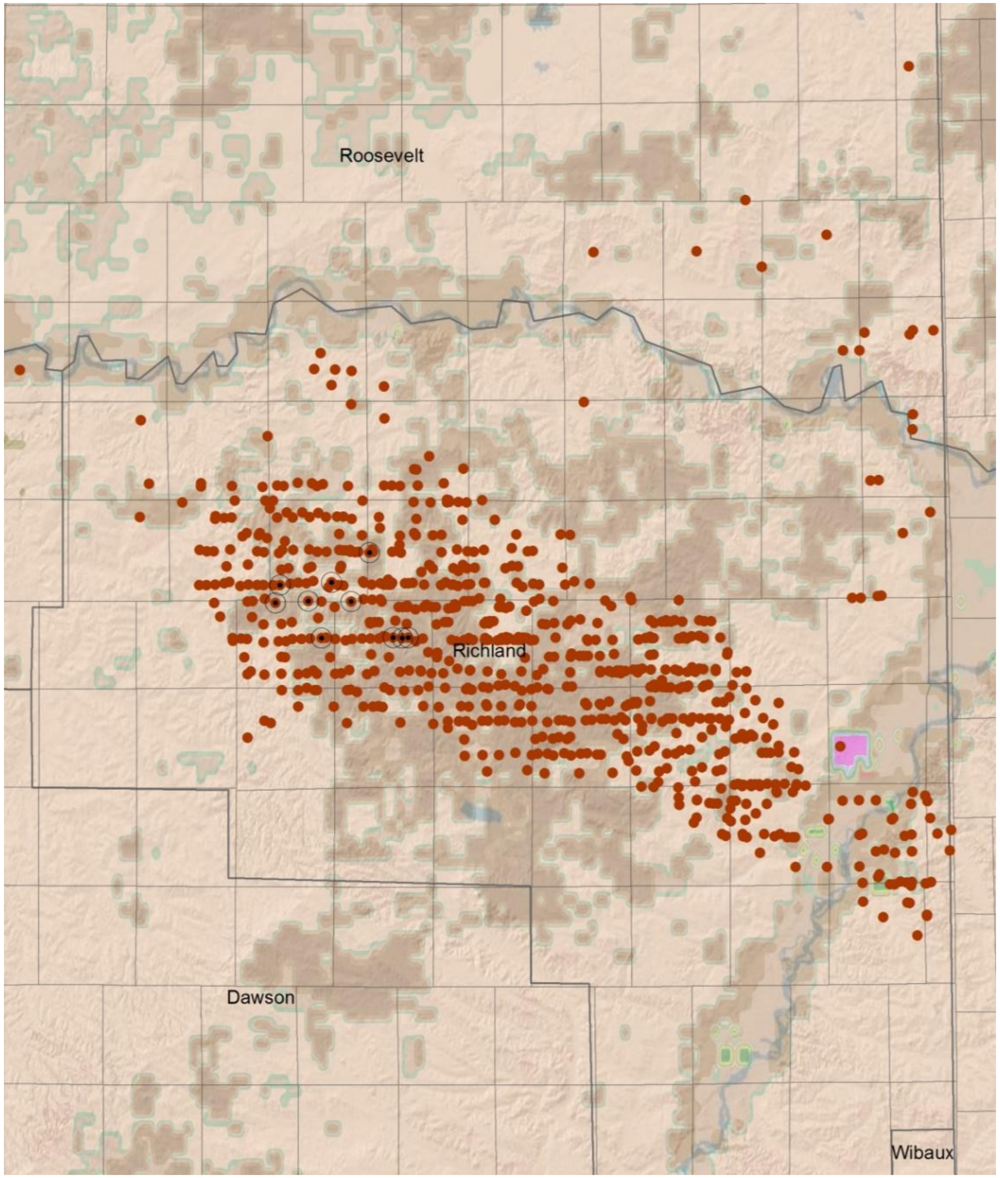
The Next Technologies for Shales

- **Fracture Complexity:** Increasing contact area of shale with the frac by increasing fracture complexity - could start as many as 30 to 70 primary fractures then produce highly developed complex fracture network with substantial contact areas. OR GO SMALLER
- **Avoid Orphaned Fractures:** Improving placement and longevity of the small fractures: Although improvements in fracture complexity open small fractures, it may not mean that cracks remain open or a viable flow path
- **Evolving Shale Gas Production Techniques:** Flowback of frac load water, determining levels of production backpressures via a choke to maximize reserve recovery or prevent formation instability, and to recover adsorbed gas while still keeping wells unloaded
- **Environmental:** Developing methods of treating and reusing frac flowback water: sharply cut dependence on fresh water for slickwater fracturing

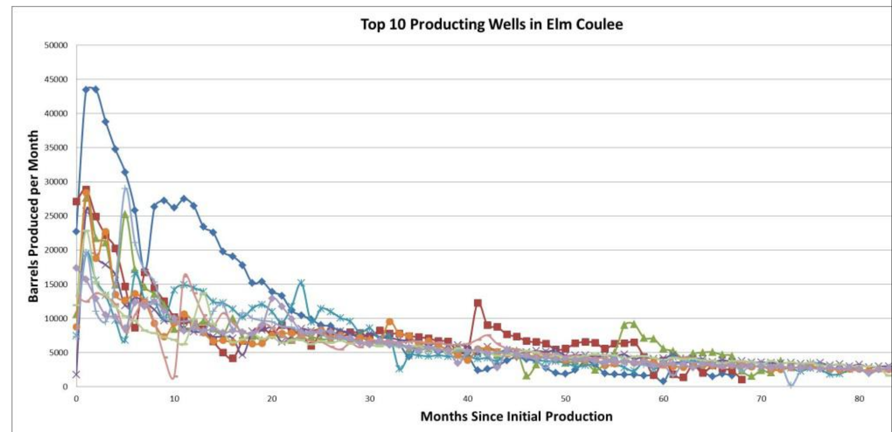
Niobrara Example: Silo Field, Wyoming

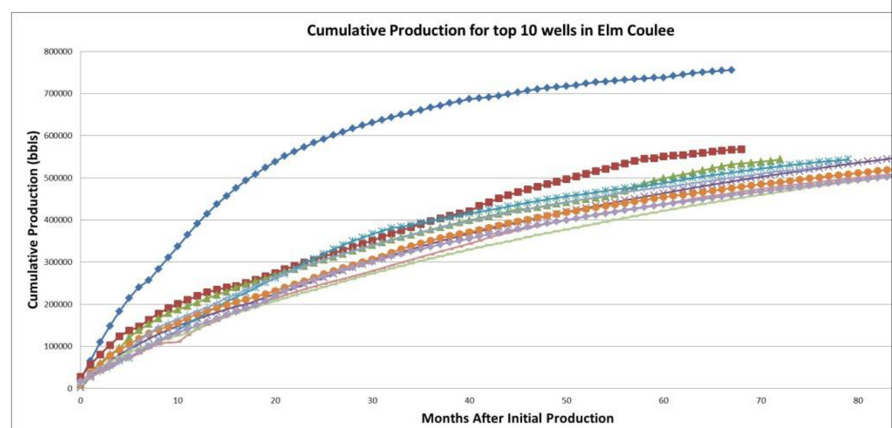


Bakken Elm Coulee Production

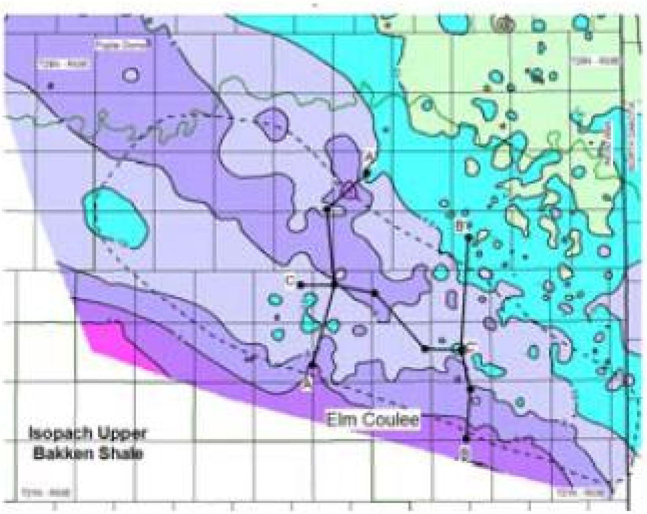


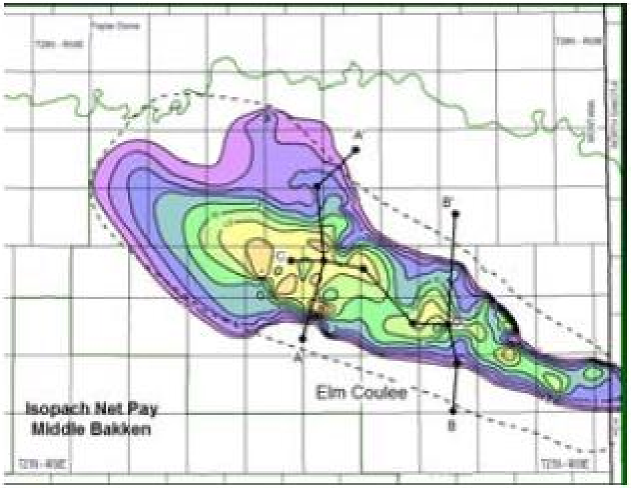
Top Ten wells (cumulative)

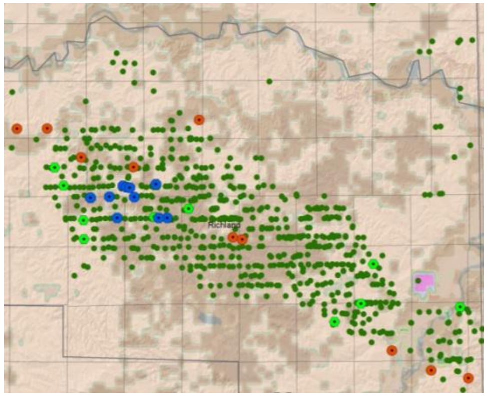


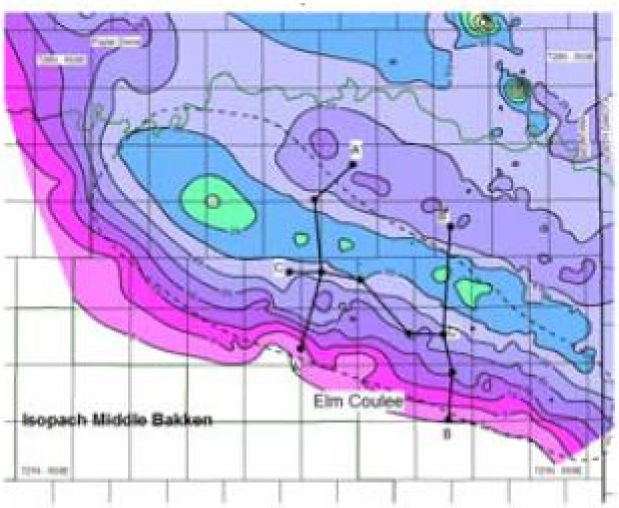


Summary of Elm Coulee Field





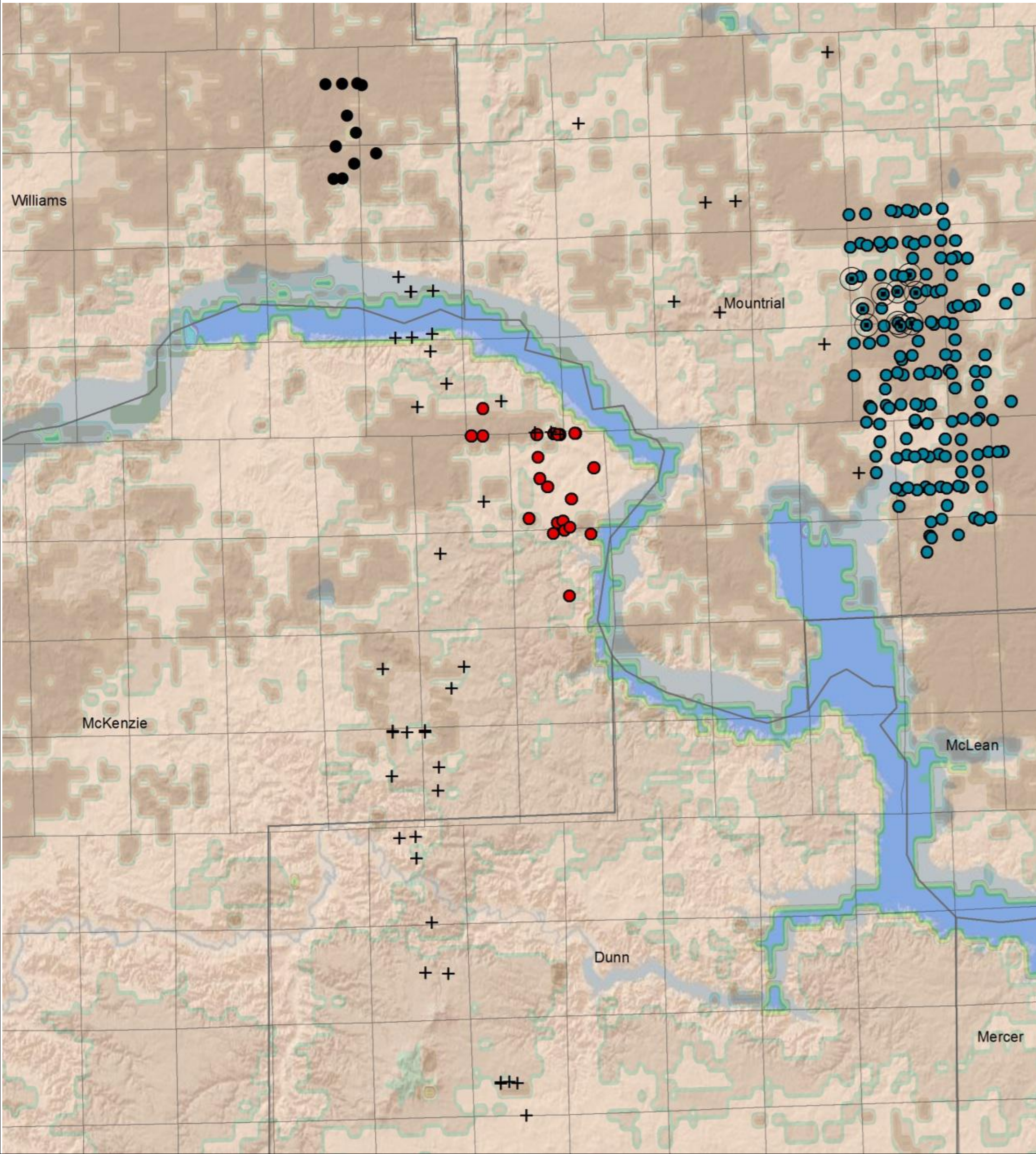




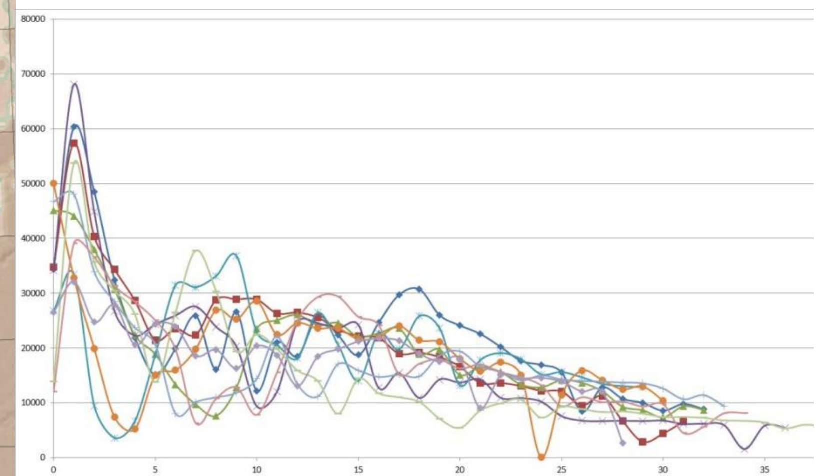
The main reservoir in Elm Coulee is the middle member which has low matrix porosity and permeability and is found at depths of 8500 to 10500 ft. The current field limits cover approximately 450 mi^2. The porosities range from 3 to 9% and permeabilities average 0.04 md...The middle Bakken is interpreted to be a dolomitized carbonate-shoal deposit based on subsurface mapping and dolomite lithology. The main production is interpreted to come from matrix permeability in the field area. Occasional vertical and horizontal fractures are noted in cores. The vertical pay ranges in thickness from 8 to 14 ft. The Bakken is slightly overpressured with a pressure gradient of 0.53 psi/ft. Horizontal wells are drilled on 640 to 1280 acre spacing units…The upper Bakken shale probably also contributes to the overall production in the field.

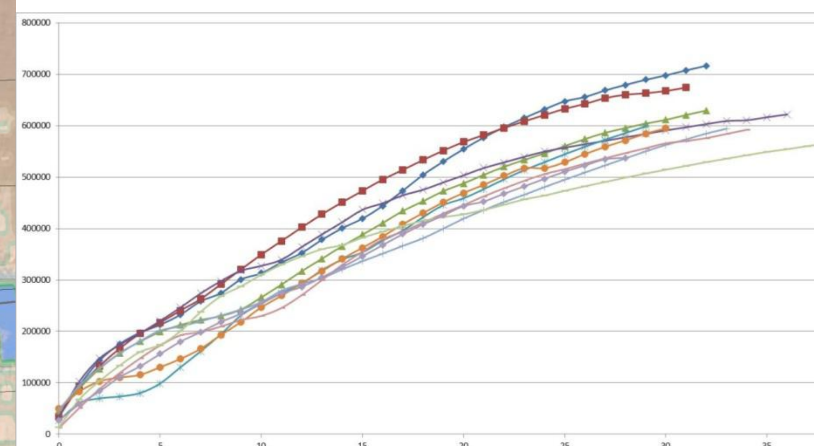
Source: Sonnenberg, Steven, 2010, Petroleum Geology of the Giant Elm Coulee Field, Williston Basin; Search and Discovery Article #20096; Posted December 14, 2010; *Adapted from poster presentation at AAPG Annual Convention and Exhibition, New Orleans, Louisiana, April 11-15, 2010*

Bakken Parshall Production



Top Ten wells (cumulative)





Relationships at Parshall Field

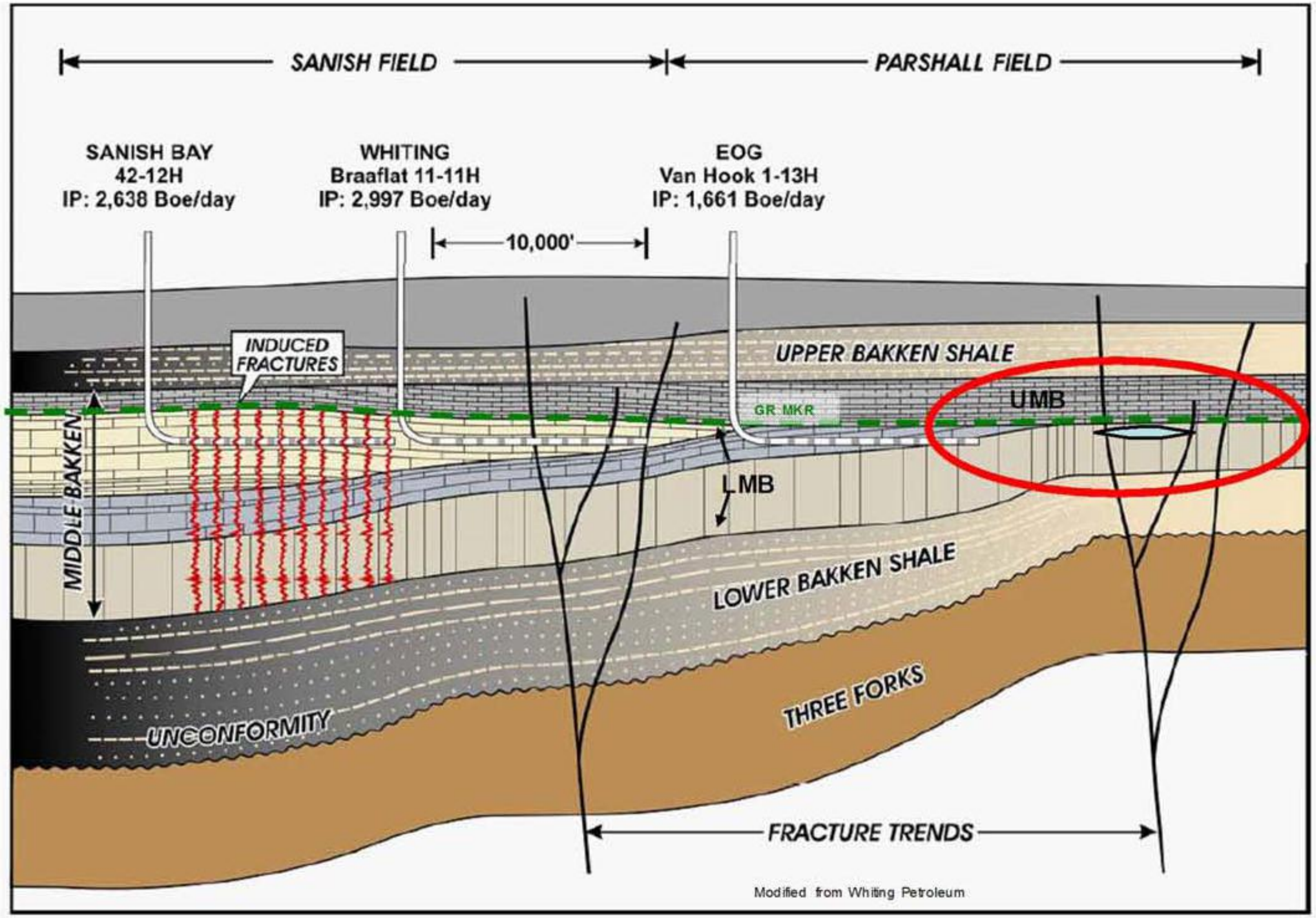


Figure 15. West-to-east schematic cross-section showing position and stratigraphy of the Bakken formations across Sanish and Parshall fields. The gamma-ray marker (green line) represents a sequence boundary that creates significant stratigraphic differences in the two fields, with Parshall Field having a much thinner middle Bakken interval. The upper middle Bakken (UMB) and lower middle Bakken (LMB) intervals are indicated. Modified from Whiting (2011).

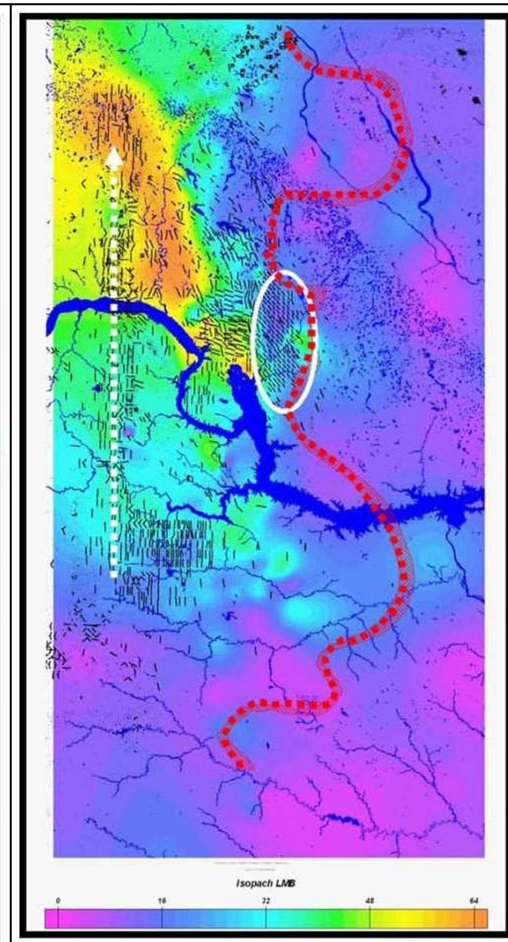
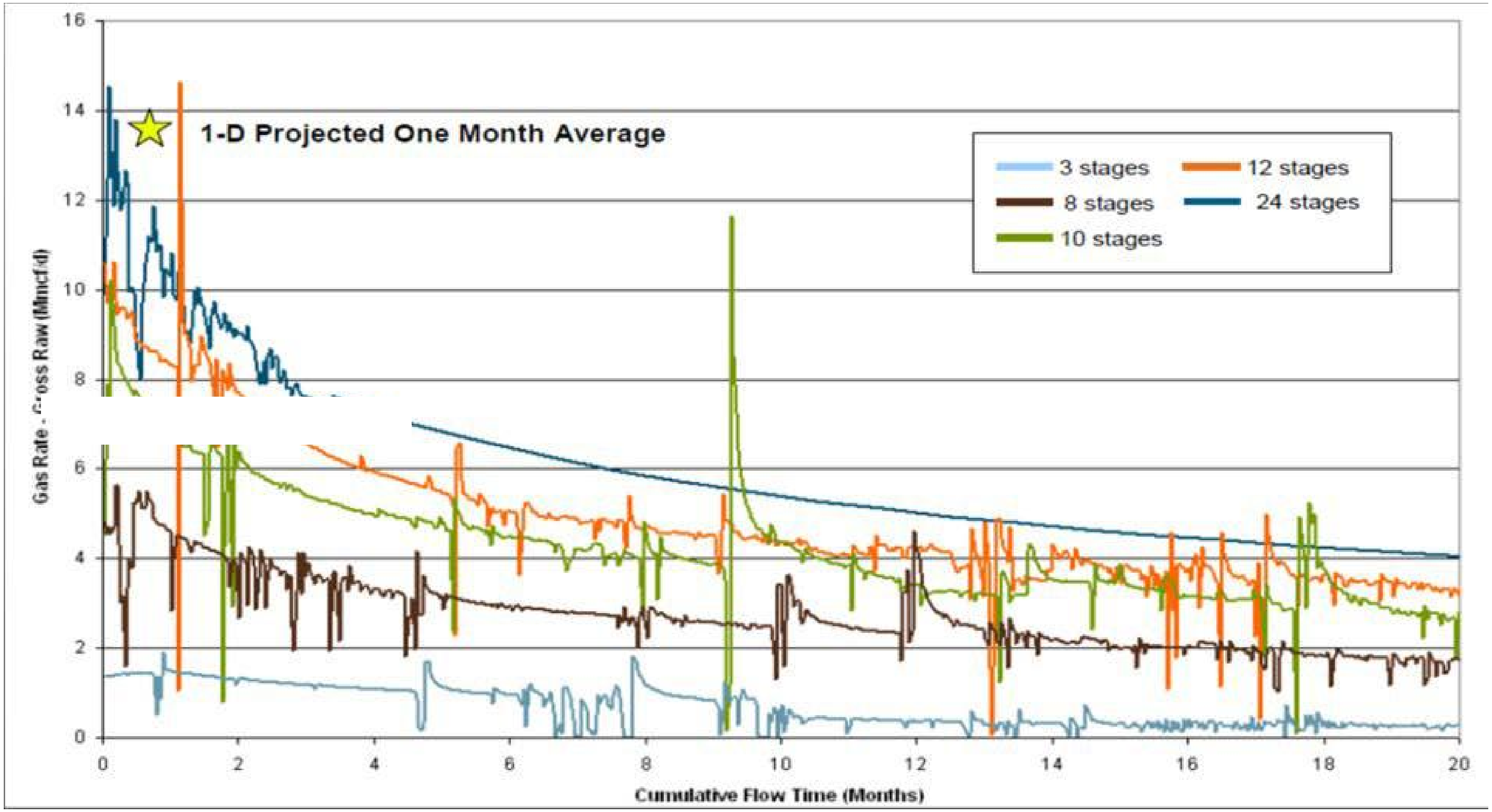


Figure 16. Isopach map of the lower middle Bakken interval (LMB). The Nesson Anticline is shown with a white dashed arrow. The Tmax 426°C contour is shown as a red dotted line. Parshall Field is indicated by a white oval. The depocenter (orange) for the LMB is along the eastern edge and tip of the northern Nesson Anticline.

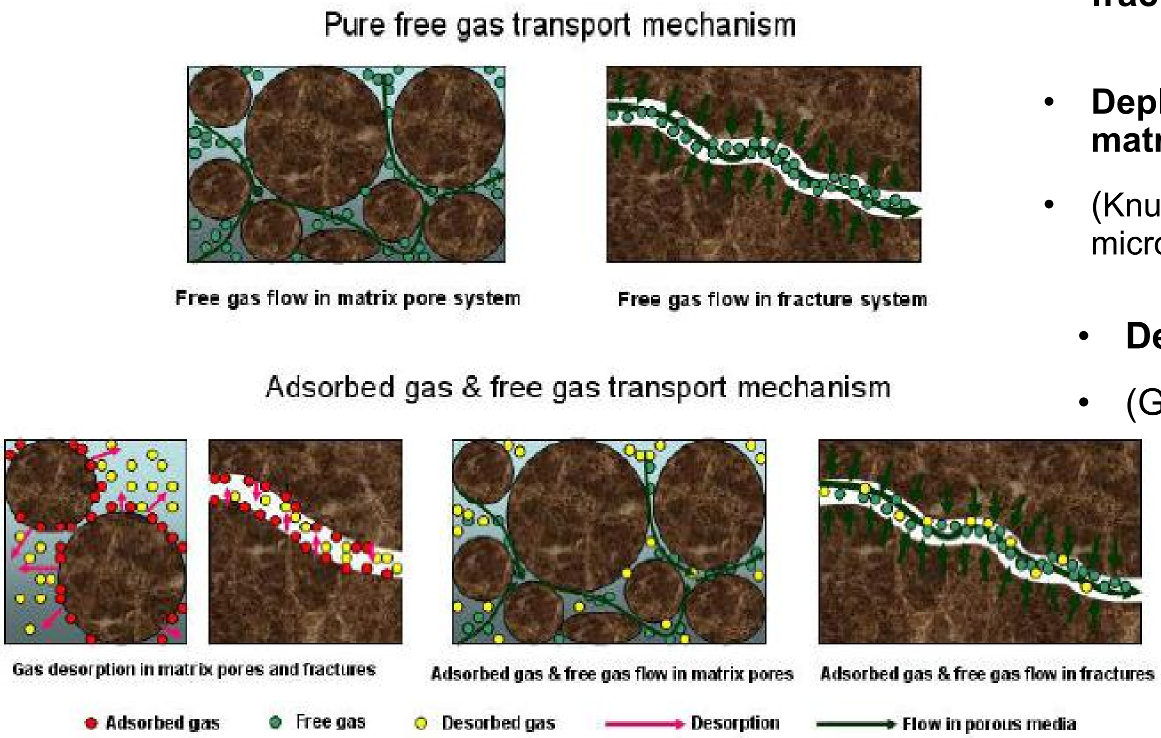
Source: Grau, et al, 2011, Characterization of the Bakken Reservoir at Parshall Field and East of the Nesson Anticline, North Dakota, in The Bakken–Three Forks Petroleum System in the Williston Basin, John W. Robinson, Julie A. LeFever, Stephanie B. Gaswirth, eds. Denver, Colo.: Rocky Mountain Association of Geologists, 2011.

What determines economic production

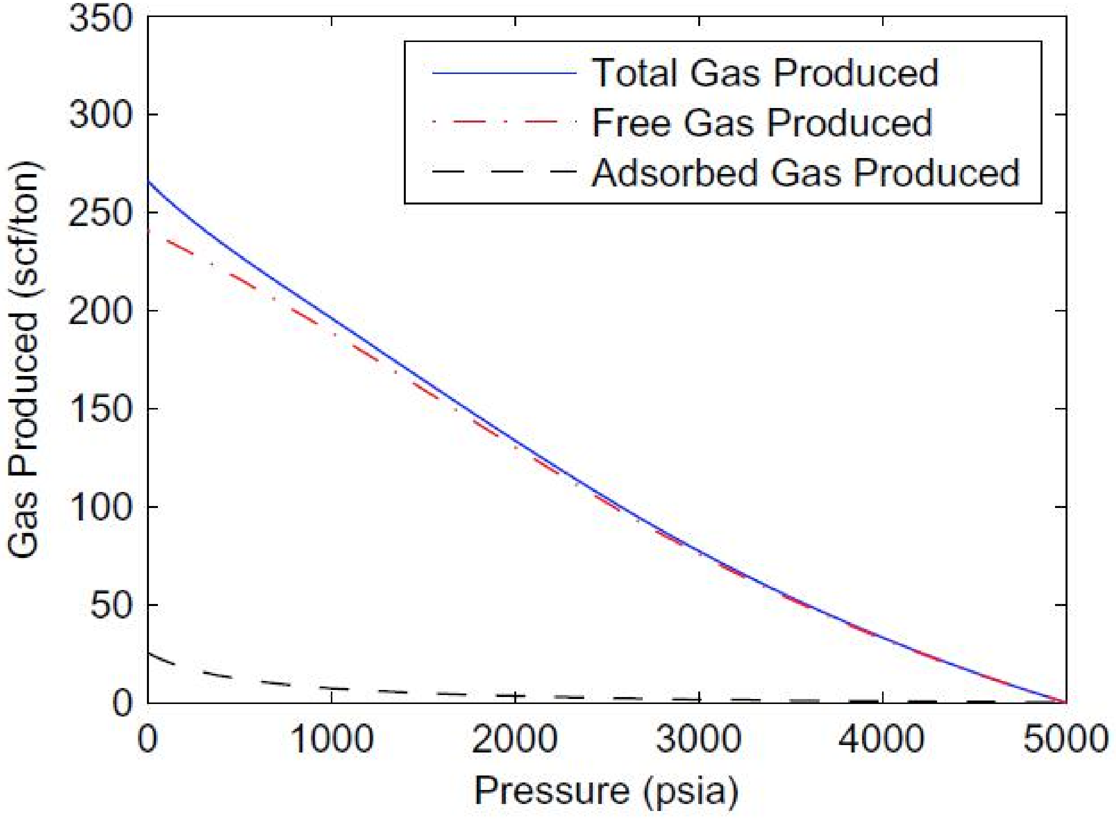


from Encana, 2011

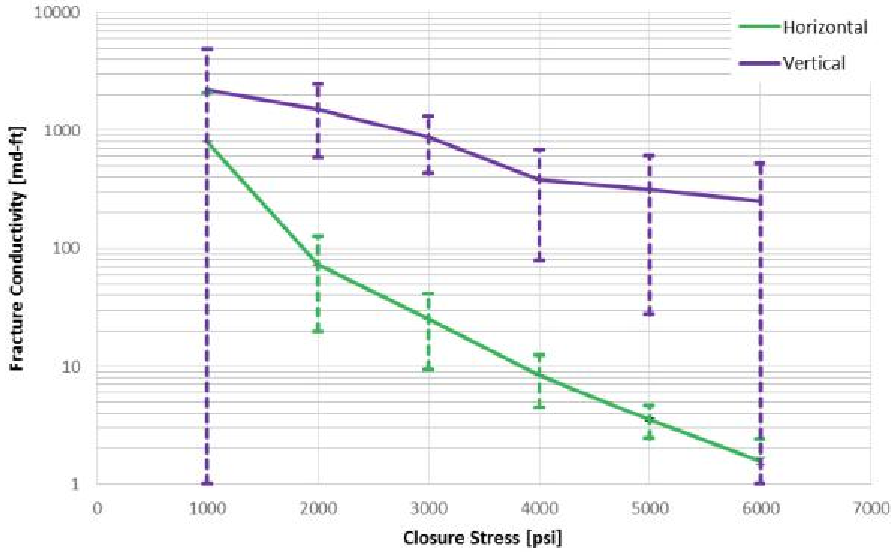
- Gas Production Mechanisms

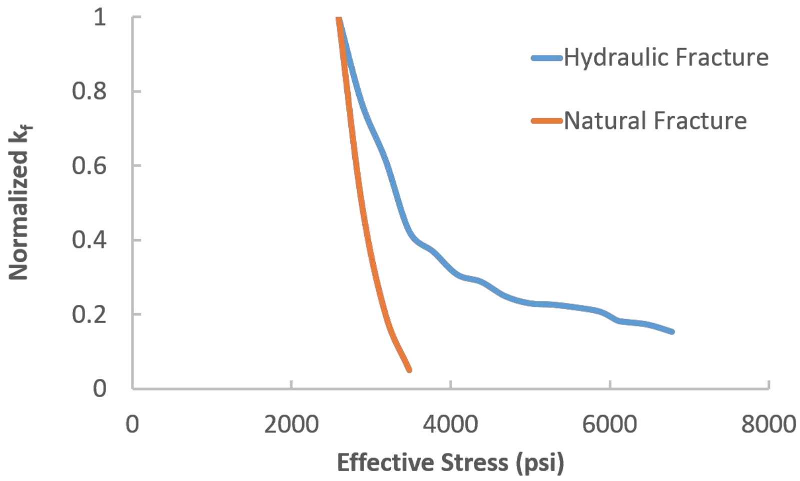


- **Depletion of free gas stored in the fracture network** (Darcy Flow)
- **Depletion of free gas stored in the matrix**
- (Knudsen diffusion and slip flow in micropores)
  - **Desorption of Adsorbed Gas**
  - (Gas diffusion)



Eect of desorption on gas production in Marcellus shale (from Heller and Zoback）





Fracture conductivity as a function of eective stress in Marcellus shale (from McGinley et al）

Table 3.1: Marcellus and Barnett Reservoir Parameters

Reservoir Property	*Marcellus*	*Barnett*
Pressure	4726 psi	3800 psi
Temperature	175°F	180°F
Matrix Porosity, ϕ_m	6%	4%
Matrix Permeability, k_m	0.0006 md	0.0001 md
Langmuir Volume	28.3 scf/ton	88 scf/ton
Langmuir Pressure	556.2 psi	440 psi
Minimum Well BHP	535 psi	1000 psi
Simulation Time	10 years	10 years

Table 2.1: Reservoir Properties for the Full-Physics Marcellus Model

Reservoir Property	*Value*
Grid Dimension	106 × 53 × 1
Grid Cell Dimension	100 × 100 × 162 ft
Reservoir Depth	8593 ft
Initial Reservoir Pressure	4726 psi
Matrix Porosity, ϕ_m	6%
Matrix Permeability, k_m	0.0006 md
Fracture Half Length, x_f	500 ft

Jamal Cherry, 2016, Stanford

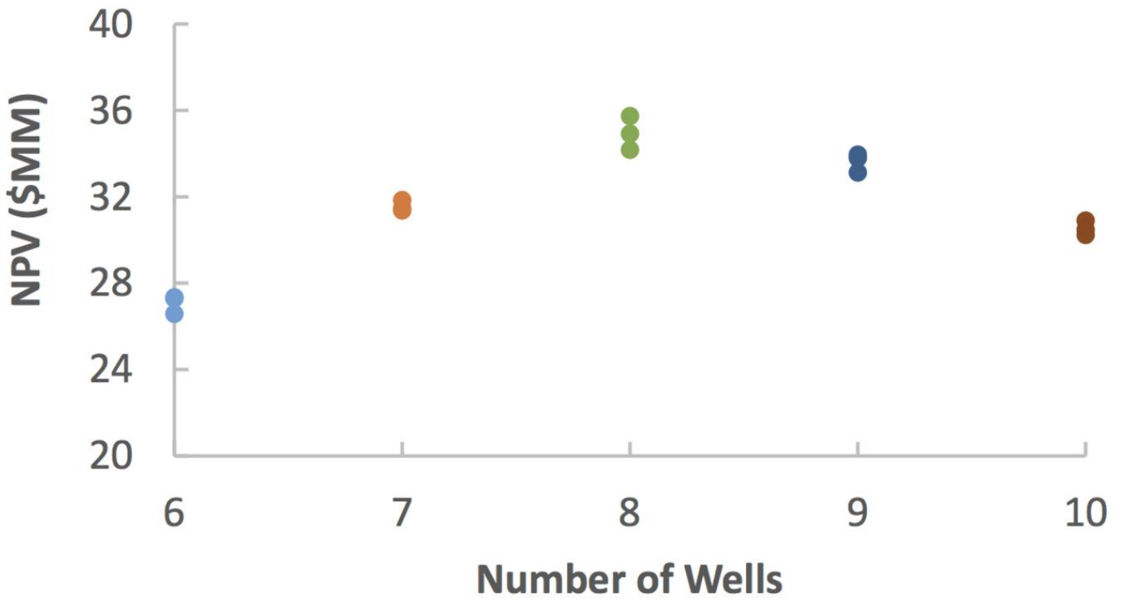
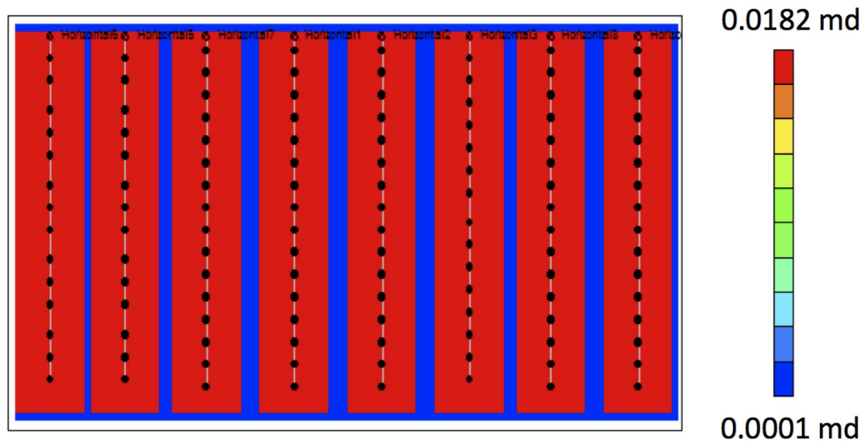
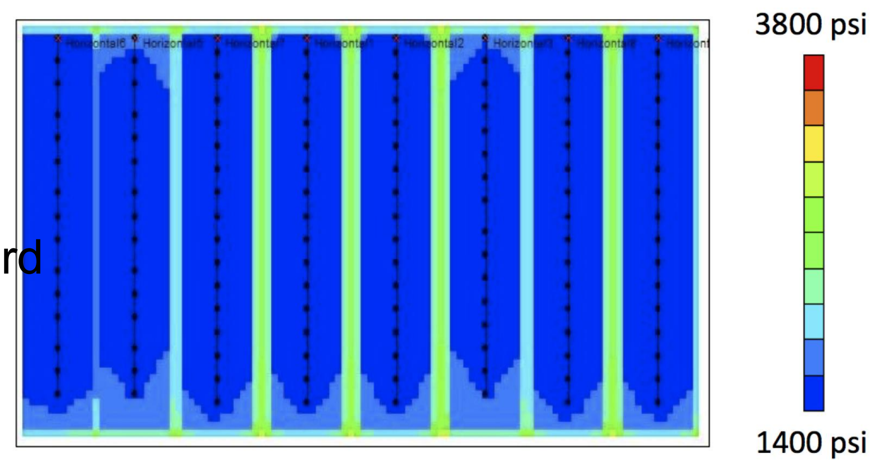


Fig. 3.5: NPVs for optimal configurations at each well count

Jamal Cherry, 2016, Stanford



(a) Permeability map



Jamal Cherry, 2016, Stanford

(b) Final pressure map

Fig. 3.7: Permeability and pressure map of the best optimum from the variable well count case

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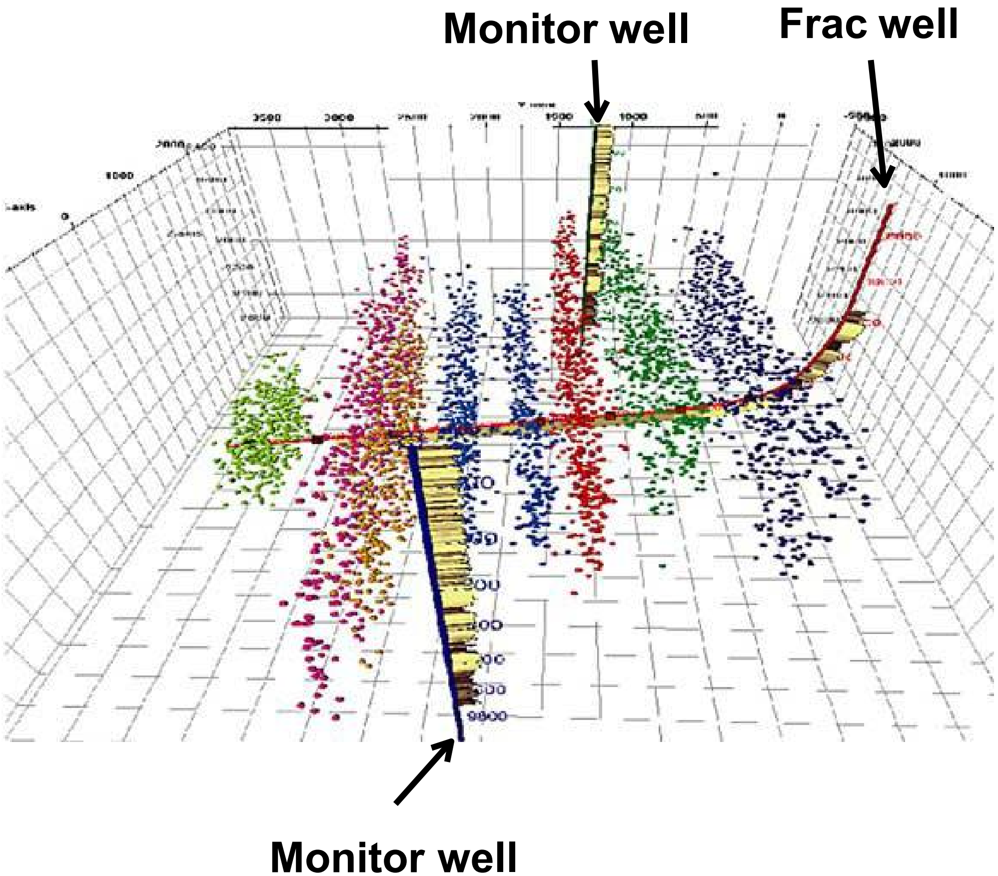
Key Success Factors for Hydraulic Fracturing

- Prediction of fracture direction, length and height
  - Regional stress maps
  - Experience in area
  - Completion design
- Monitoring of fracture creation
  - Fluid volumes, proppant placed
  - Microseismic monitoring (borehole and surface)
  - Tilt monitoring
  - Flow noise (via fiber optics)
- Evaluation of fracture performance
  - Production logs
  - Tracer measurements
  - Flow noise

Microseismic Monitoring of Hydraulic Fracturing

- Geophones in a monitor well(s)
- Listen during each frac stage
- Locate the events
- Modify program to ensure you don't frac out of zone



https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/archive/prmrndrstndngshlgs2009/prmrndrstndngshlgs2009-eng.html

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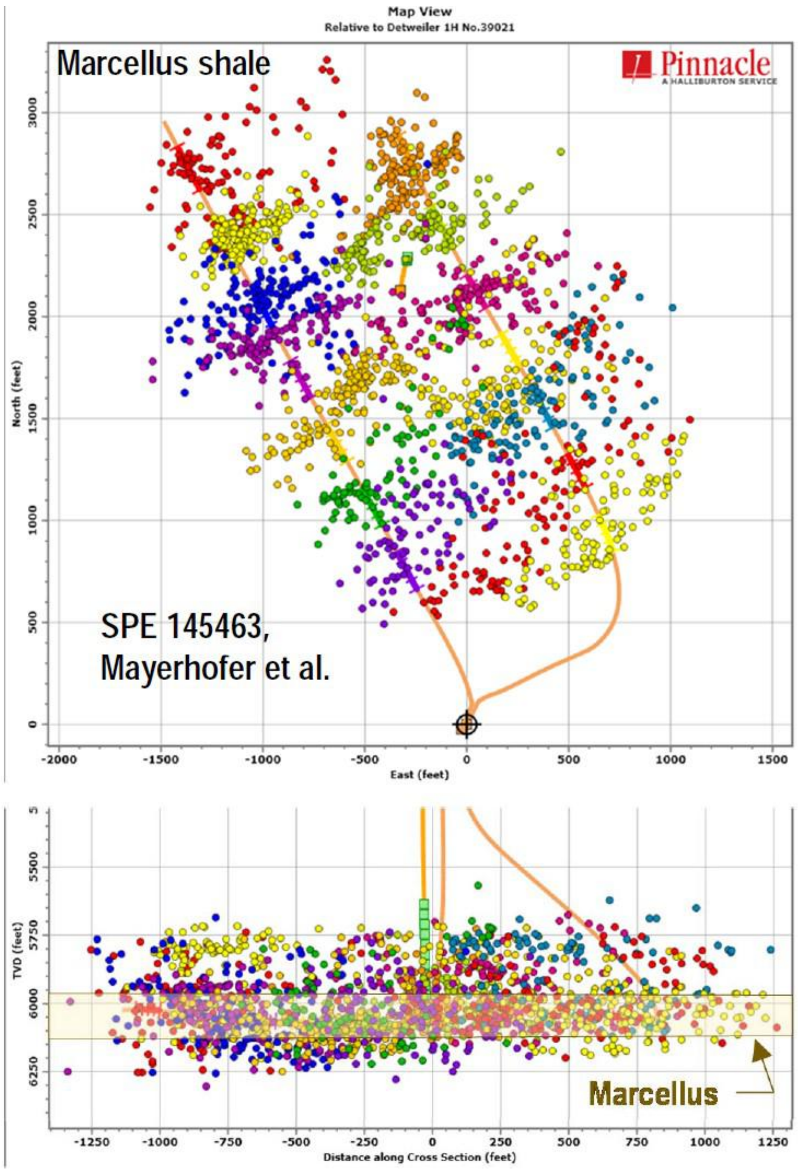
Microseismic monitoring is a valuable tool for optimizing

- Well layout (trajectory)
- Well spacing
- Stage lengths
- Perf clusters and/or valves & packers
- Stimulation design
- Fracture height and length
- Complexity
- SRV



N. Warpinski

• Frac Process

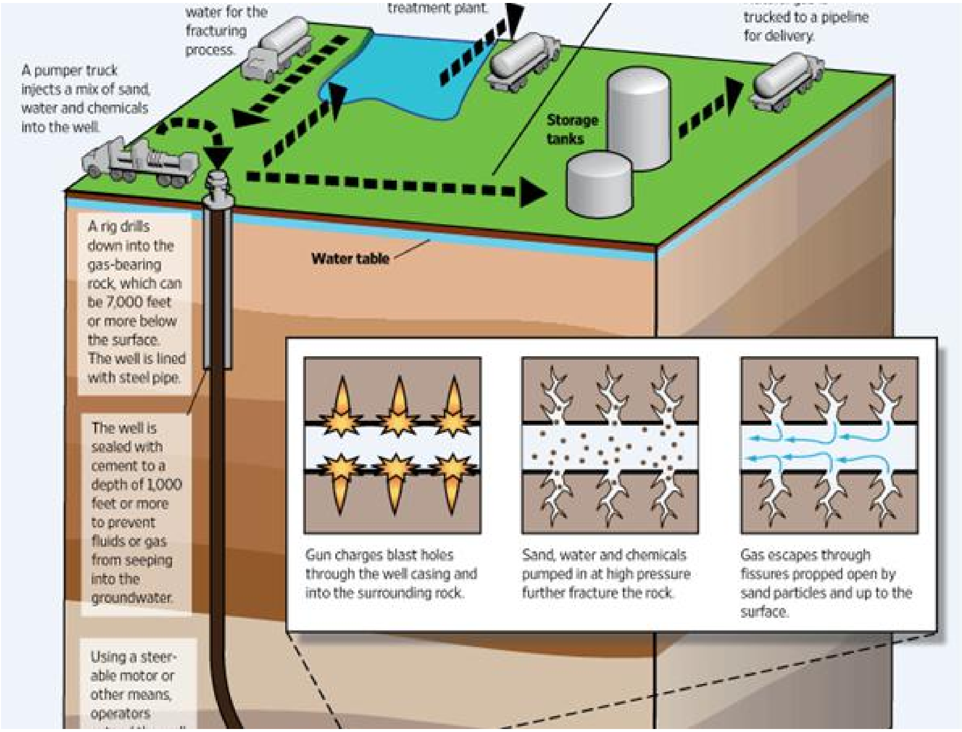
1. Pad injection

2. Increased prop concentrations

3. Flush

4. Pressure bled off

5. Recovery of injected fluids



• Frac Parameters

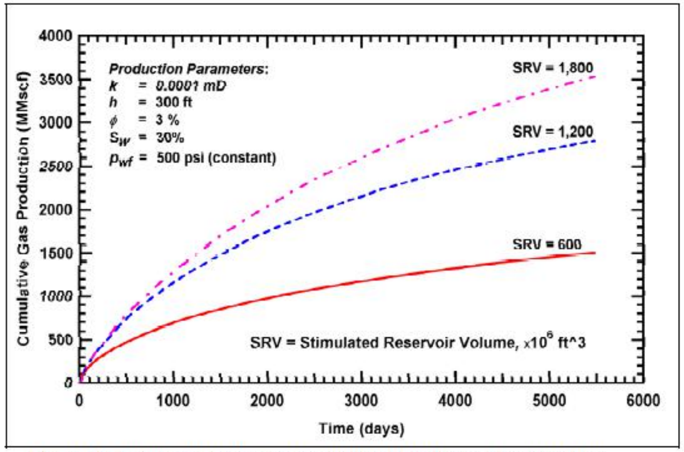


Figure 8: Impact of network size on cumulative gas production

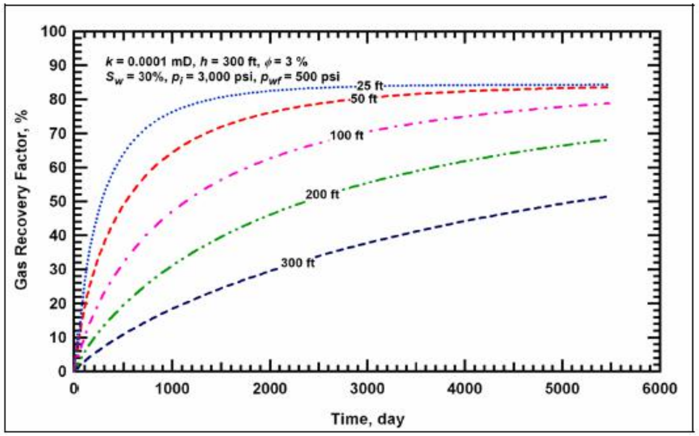


Figure 12: Impact of fracture spacing on gas recovery factor (100 nano-darcy shale permeability)

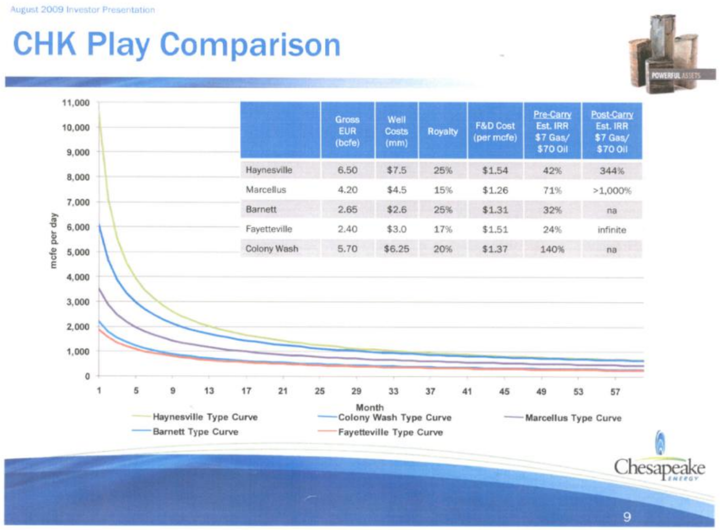
Frac Network Size

Higher SRV results in better well performance.

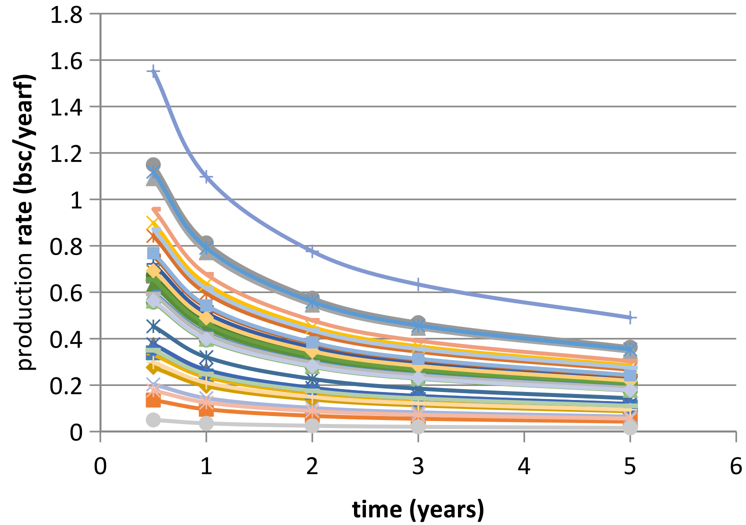
Frac Network Density

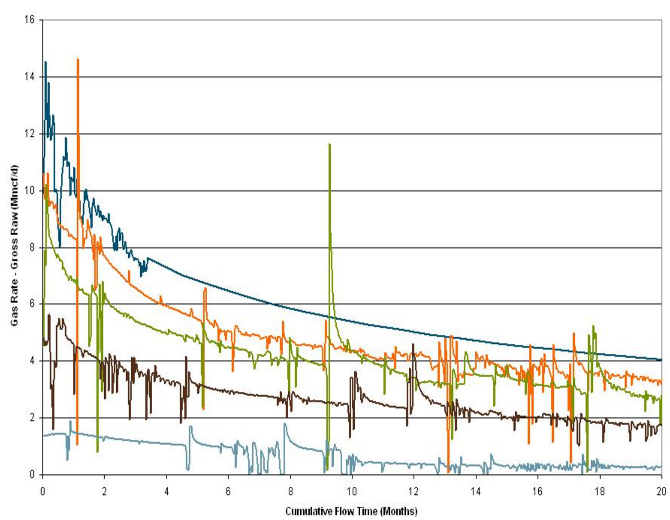
Small frac spacing results in better well performance

Shale Gas Production Data

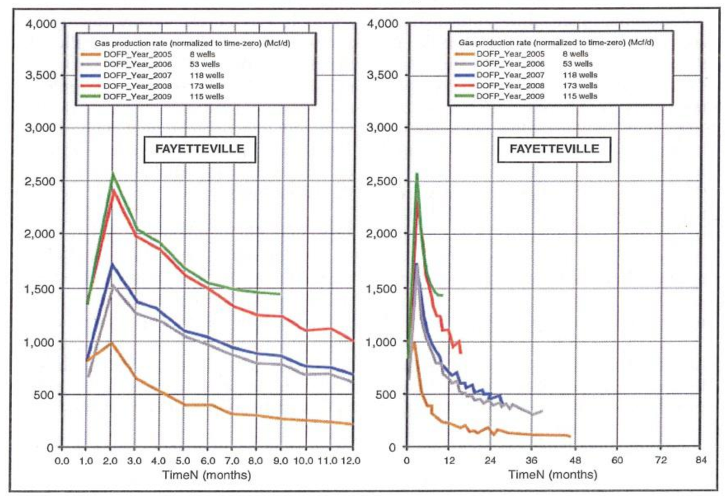


	Gross EUR (bcfe)	Well Costs (mm)	Royalty	F&D Cost (per mcfe)	Pre-Carry Est. IRR $7 Gas/ $70 Oil	Post-Carry Est. IRR $7 Gas/ $70 Oil
Haynesville	6.50	$7.5	25%	$1.54	42%	344%
Marcellus	4.20	$4.5	15%	$1.26	71%	>1,000%
Barnett	2.65	$2.6	25%	$1.31	32%	na
Fayetteville	2.40	$3.0	17%	$1.51	24%	infinite
Colony Wash	5.70	$6.25	20%	$1.37	140%	na



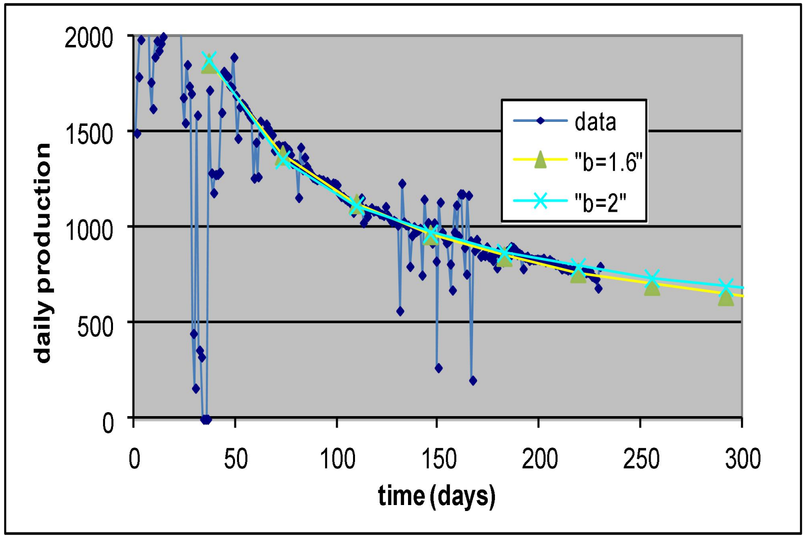


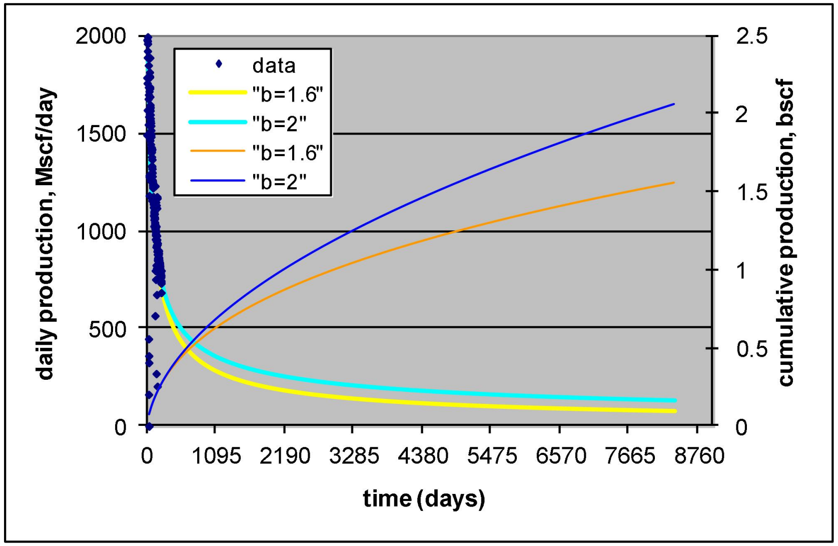
Fayetteville Shale First-Year and Total Production Rates Color-Coded by Year



Baihly et al (SPE 135555)

Conventional Production Analysis Techniques:





Data Analysis techniques

1. Conventional Decline Analysis—Arps $$q = \frac{q_i}{(1+bD_i t)^{1/b}} \quad for \quad 0<b<1$$

Semi-analytic solution

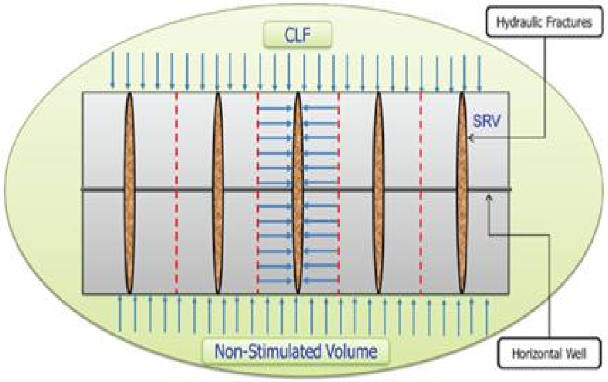
Theory suggests that for a substantial period of time cumulative production and production approximated by

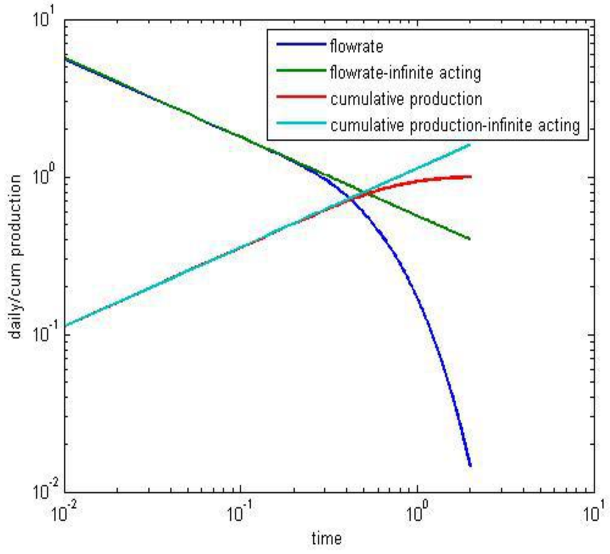
$$Q = C_p \sqrt{t}, \quad q = \tfrac{1}{2} \frac{C_p}{\sqrt{t}}$$

where C_p depends on

- Pressures (bhfp, pore or reservoir pressure)
- Reservoir quality/ GIP (permeability, porosity)
- Gas properties (viscosity, compressibility, equation of state)
- Productive fracture surface area

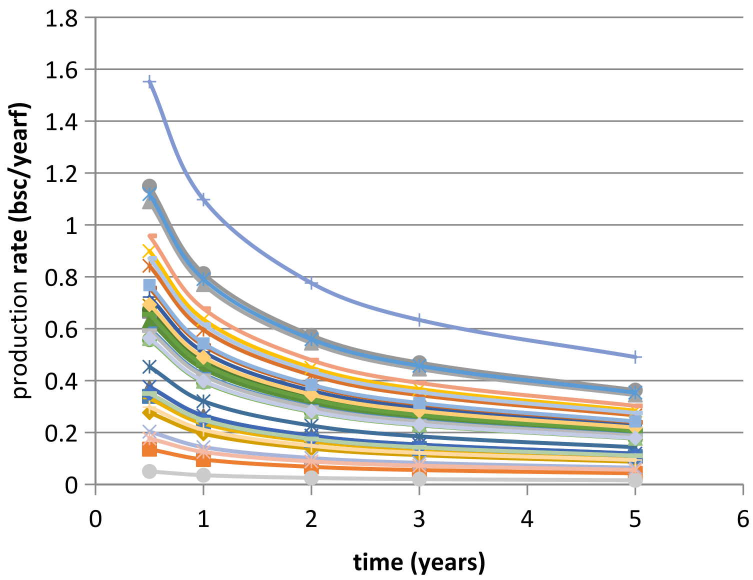
$$C_p = A \frac{\left(p_r^2 - p_w^2\right)}{p_s} \sqrt{\frac{c \phi_m k_m}{\pi \mu}}$$



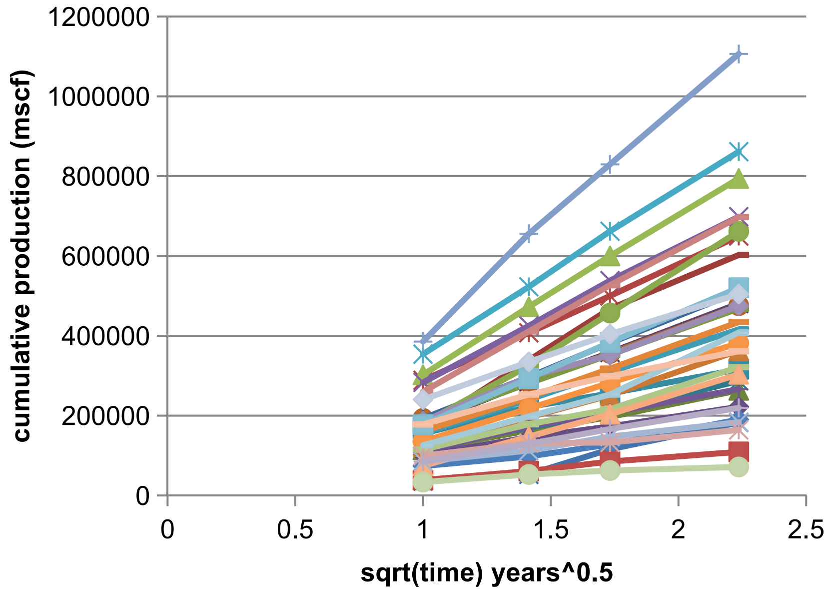


New Production Data Analysis Method

OLD

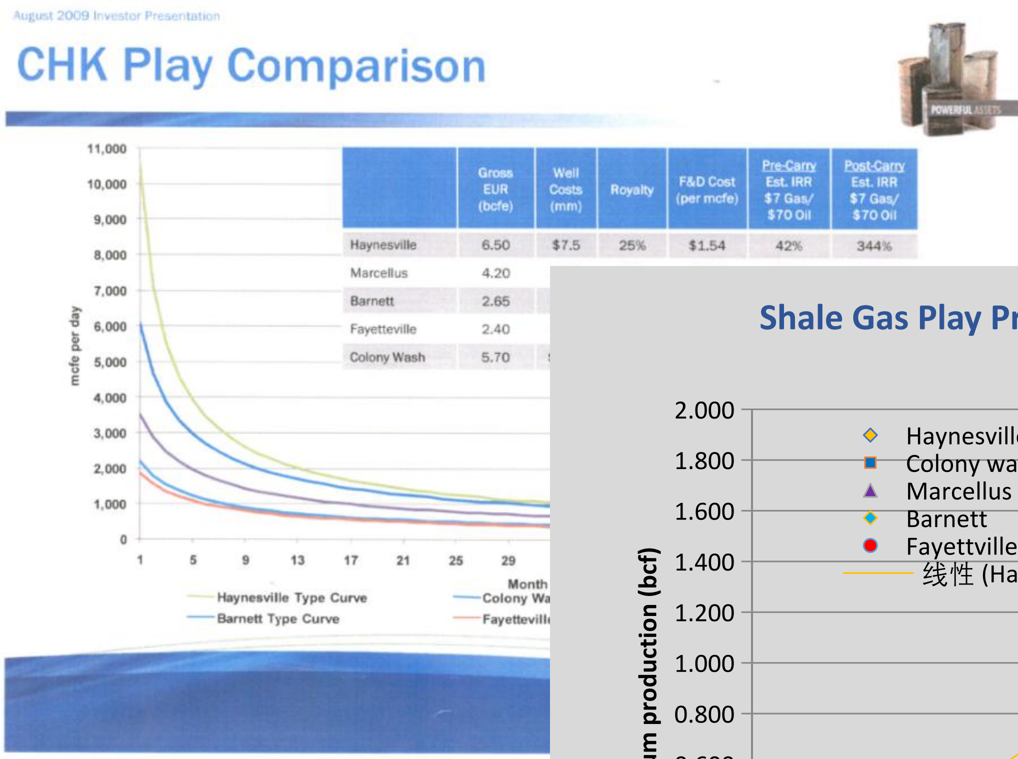


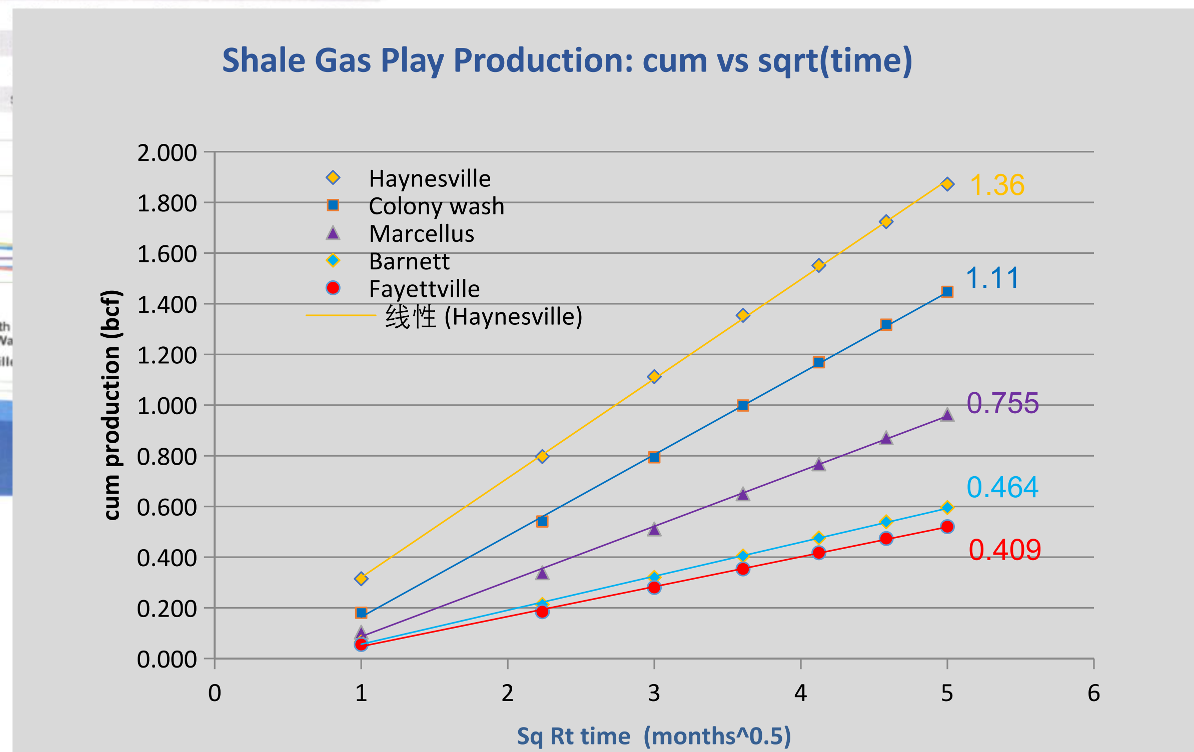
NEW



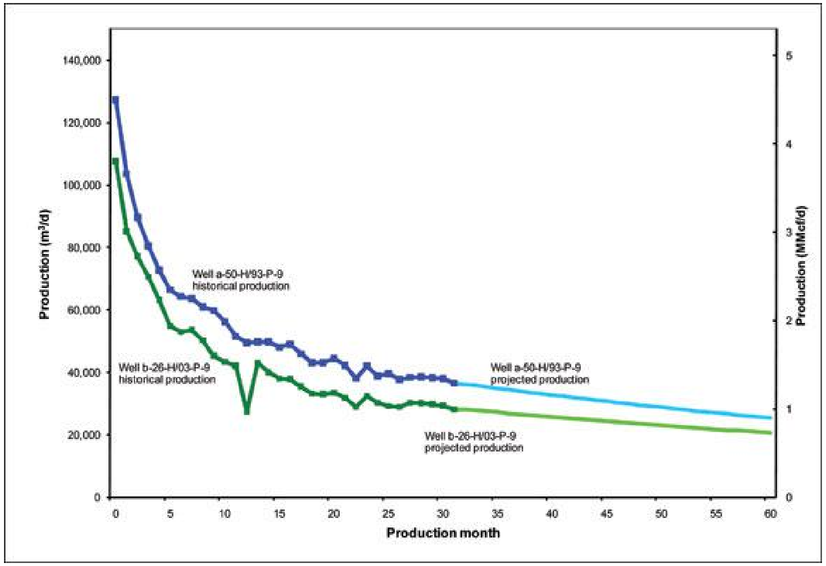
- Production data analysis is efficient and effective
- Anticipates and explains non-uniqueness of conventional history matching
- Slope of the line is the best metric of well productivity
- Solution is valid for many years of production
- Provides a rational basis for evaluating the production drivers, quantifying “what makes a good well”, assessing play-by-play variations and estimating productive fracture surface area.

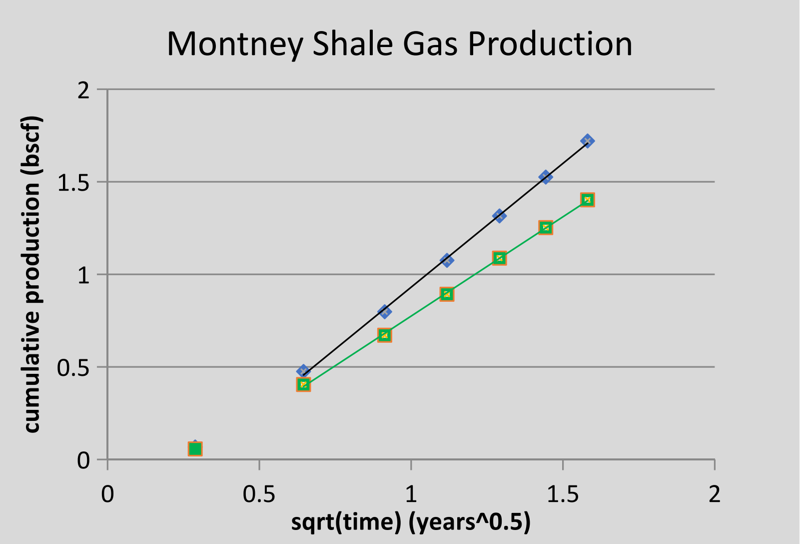
Play-by-play Production Comparison

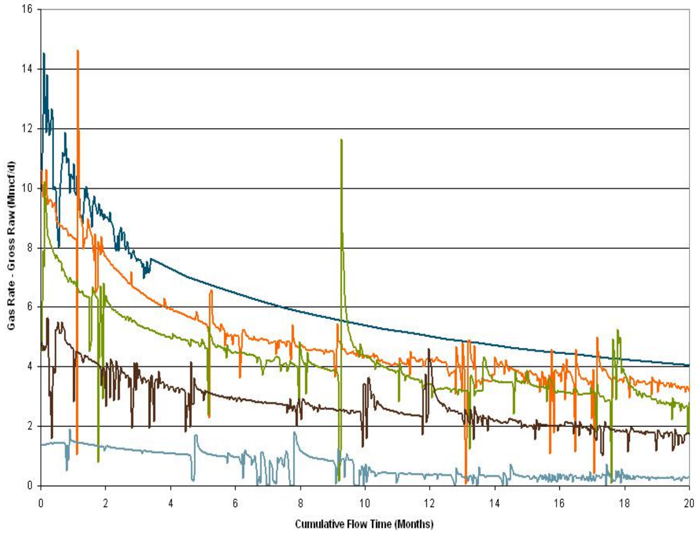


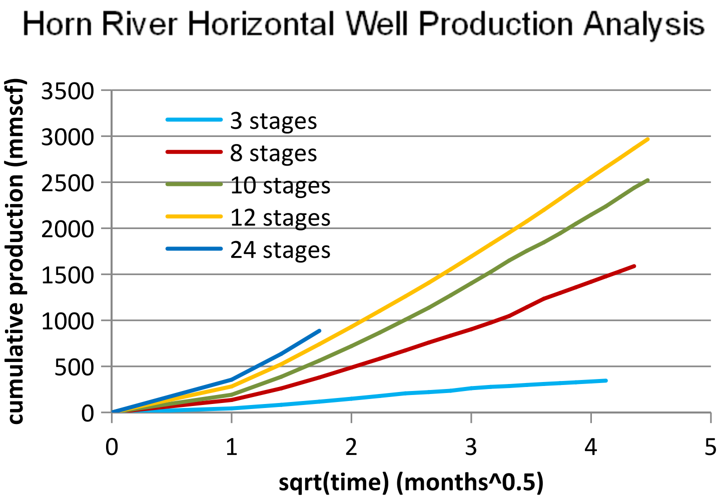


Shale Gas Production Data Analysis

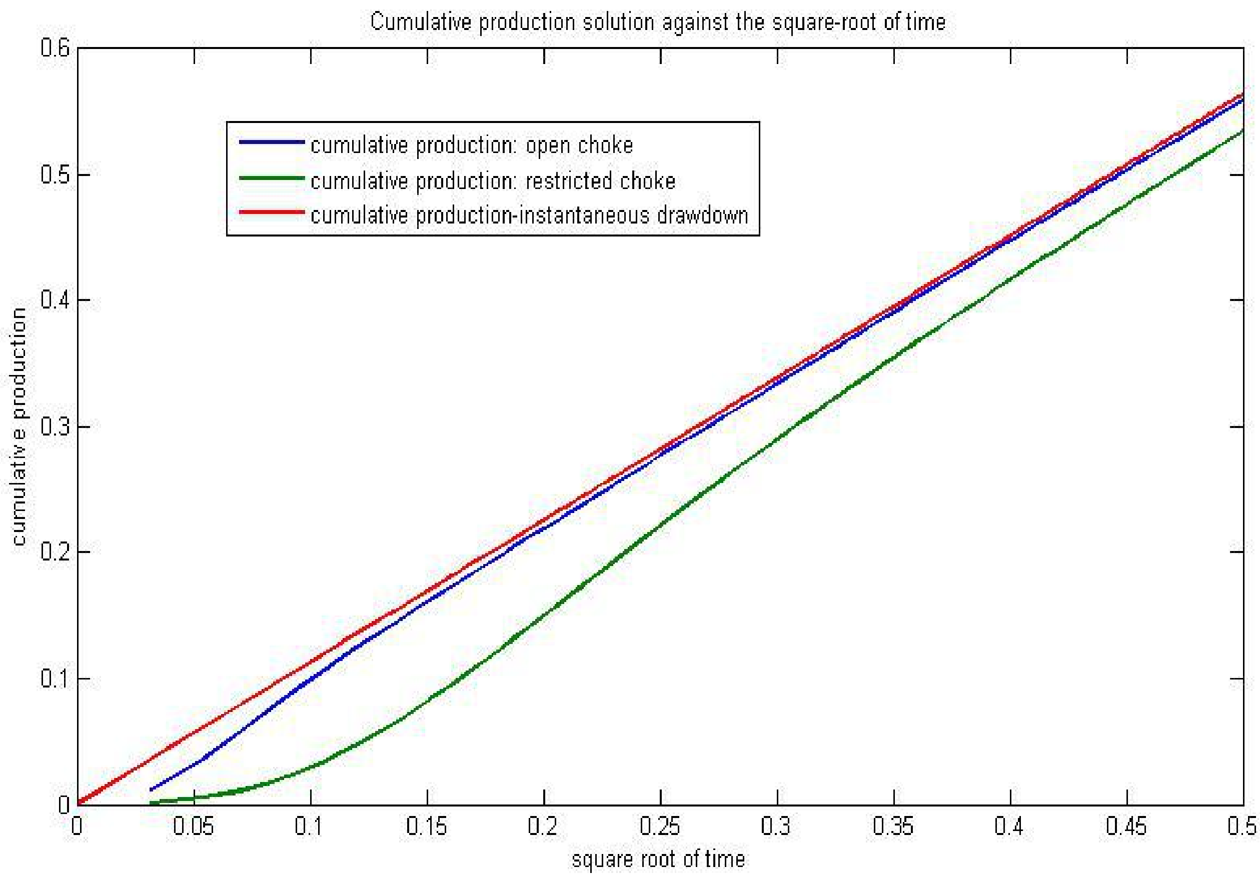






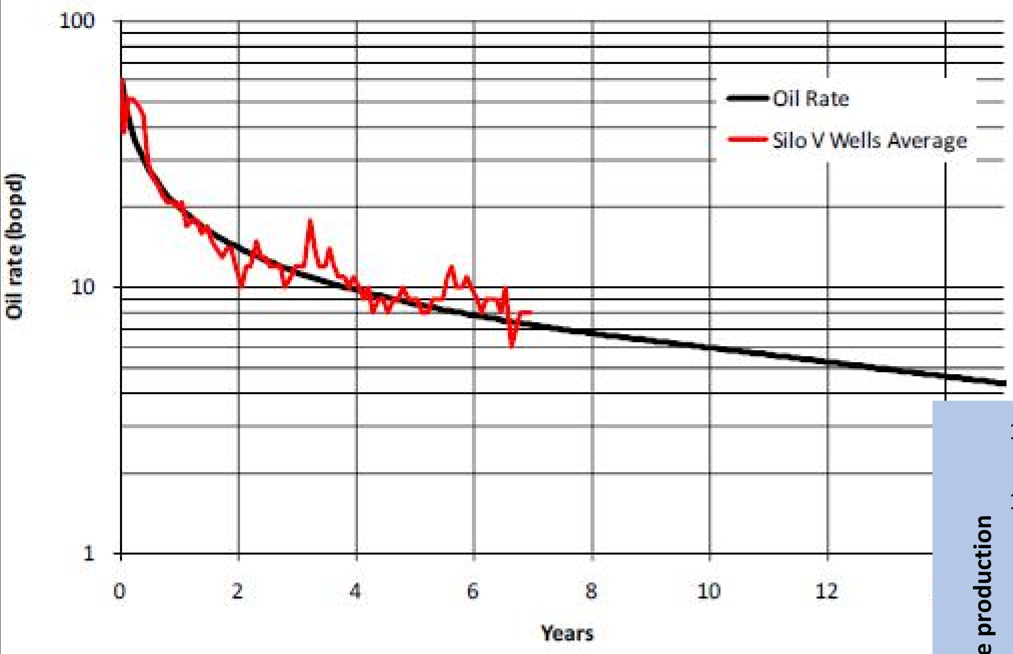


Impact of Clean-up Period

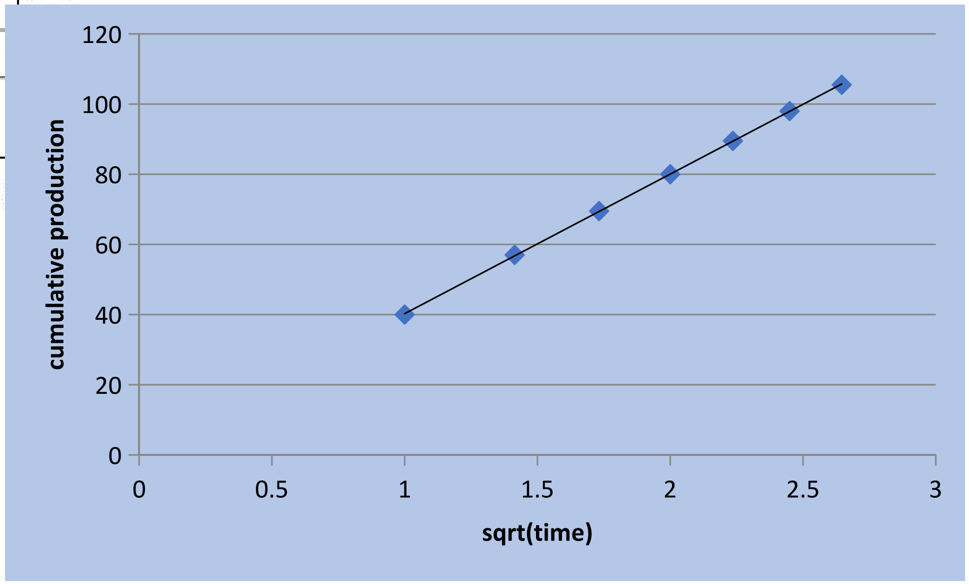


Oil Production Data

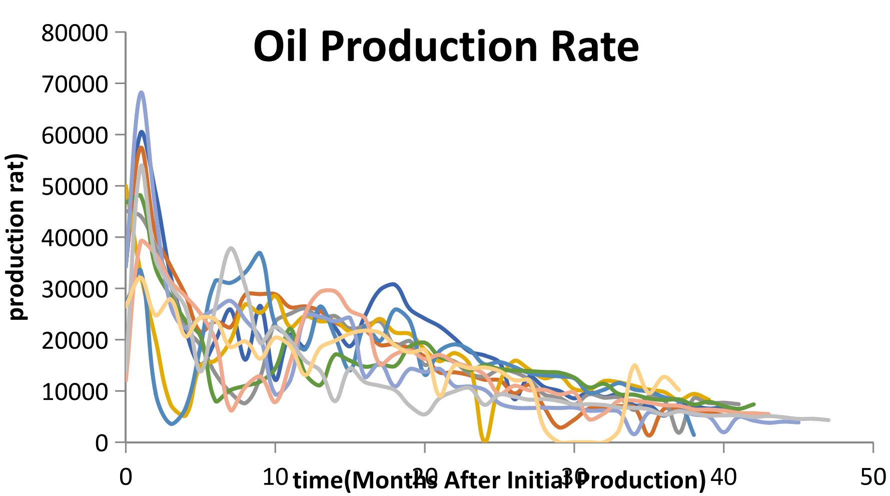
- Silo field, Niobrara
- Single-phase ?

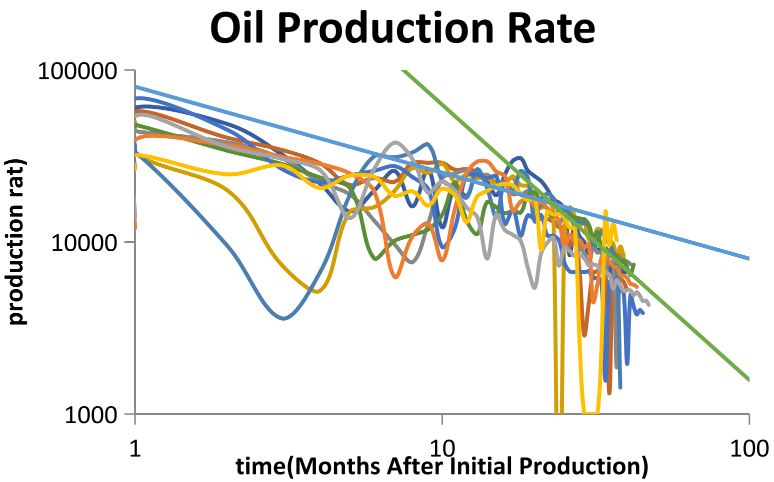


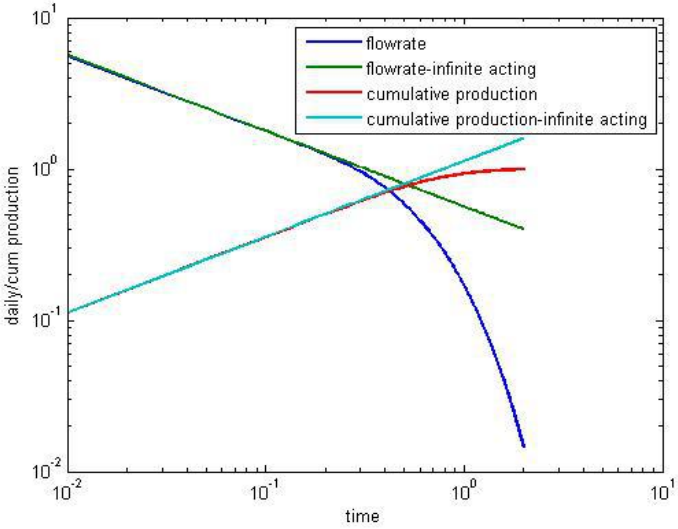
Steep decline
b=2

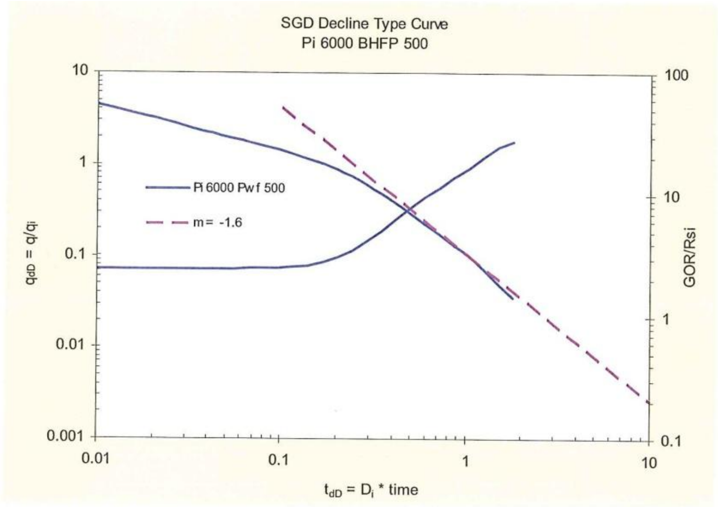


Oil Production Data-Parshall field



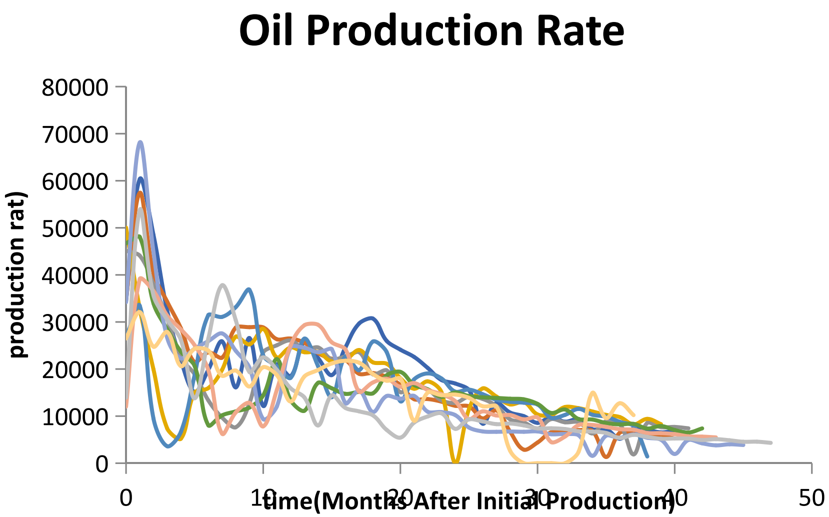


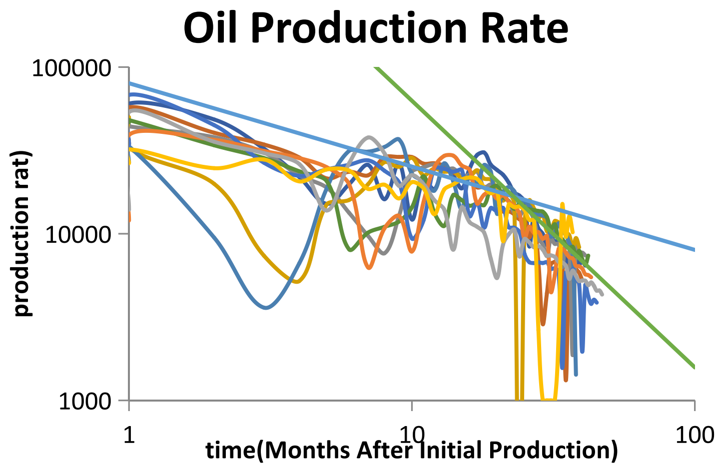


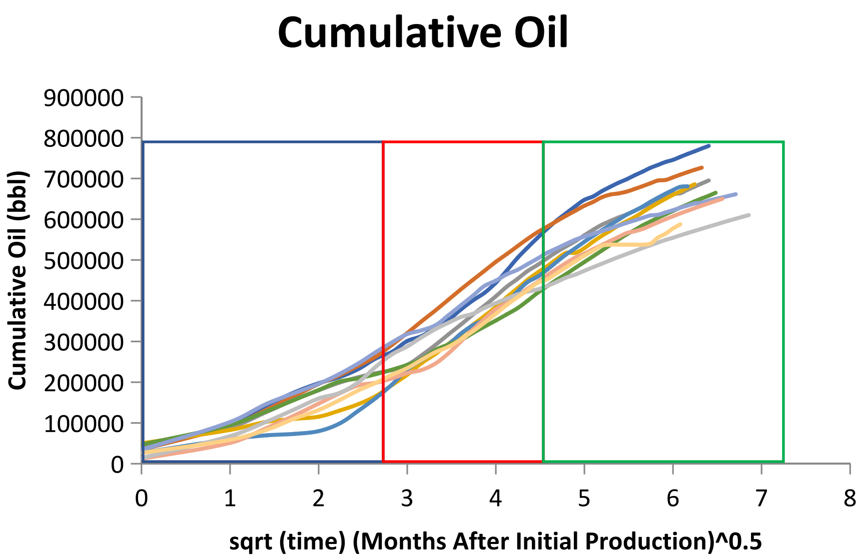


Gonzales and Callard, SPE 142382

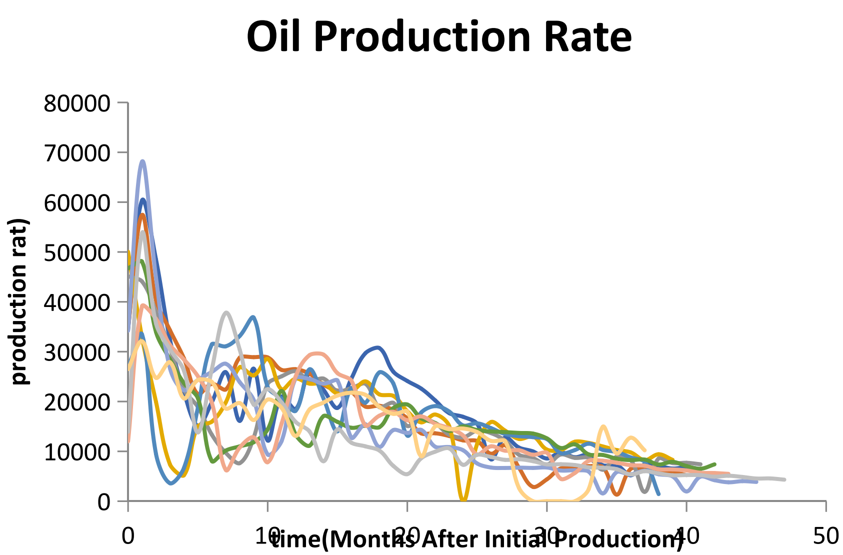
Oil Production Data

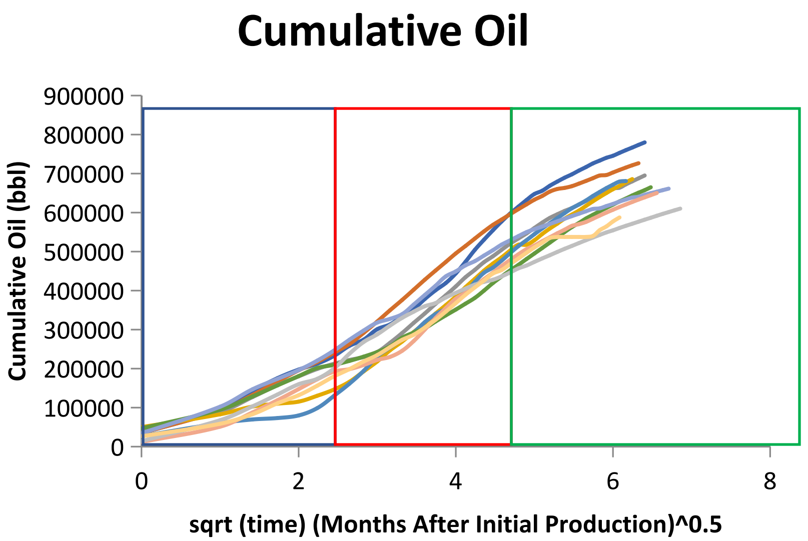


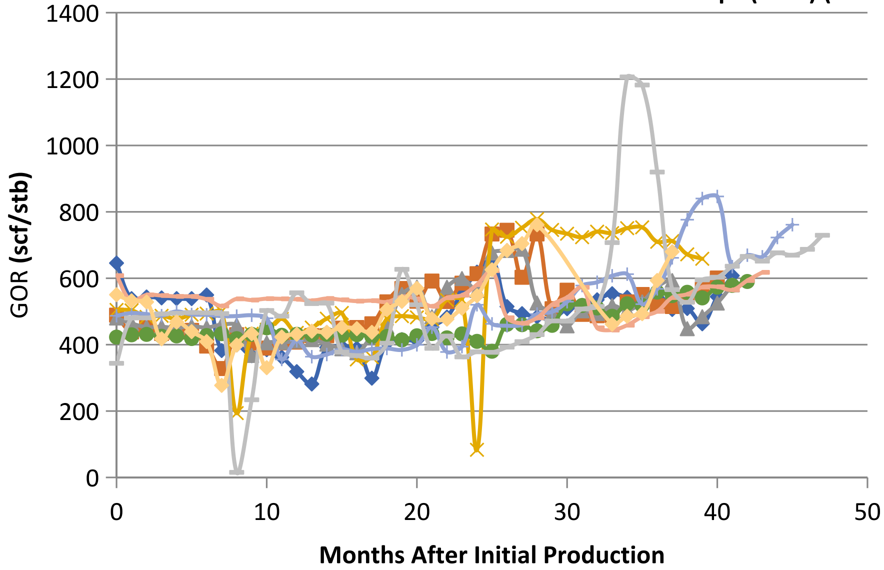




Oil Production Data



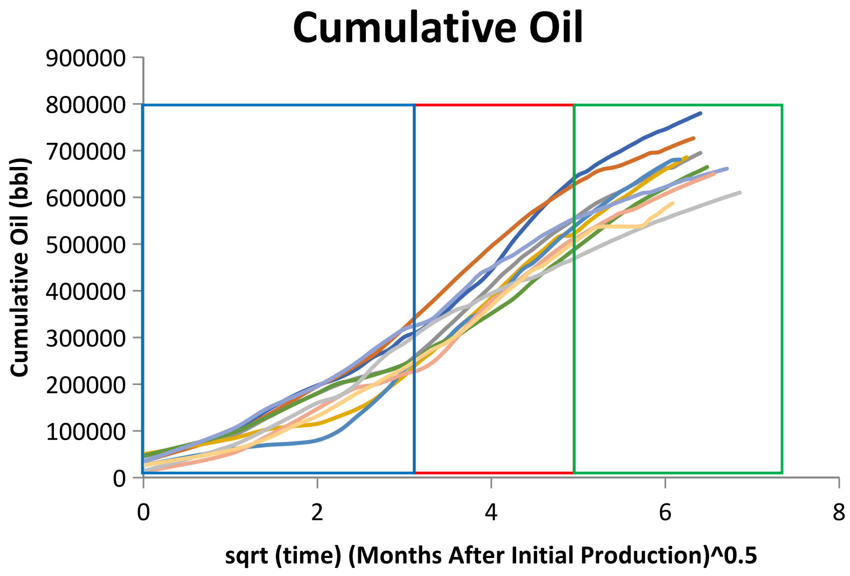




Oil Production Analysis

So far we have identified three main flow periods

1. *Linear flow into fractures, but impacted by variable drawdown*
2. *'conventional" root time period where GOR is constant, free gas in reservoir is immobile.*
3. *Emergence of two-phase flow leads to a reduction in relative permeability and a concomitant reduction in production rate.*



Key Factors

- *Reservoir pressure*
  - higher pressure provides energy to drive oil out of the reservoir.
  - maintaining reservoir pressure above the bubble point (pressure at which dissolved gas separates from oil) increases the recovery of oil.
- *Gas - oil ratio (GOR)*
  - above the bubble point, GOR is constant, well produces as single-phase.
  - below the bubble point, GOR increases rapidly, free gas competes with oil for flow and may hinder, not help, oil production.

Is "Tight Oil" Development and Growth Sustainable?

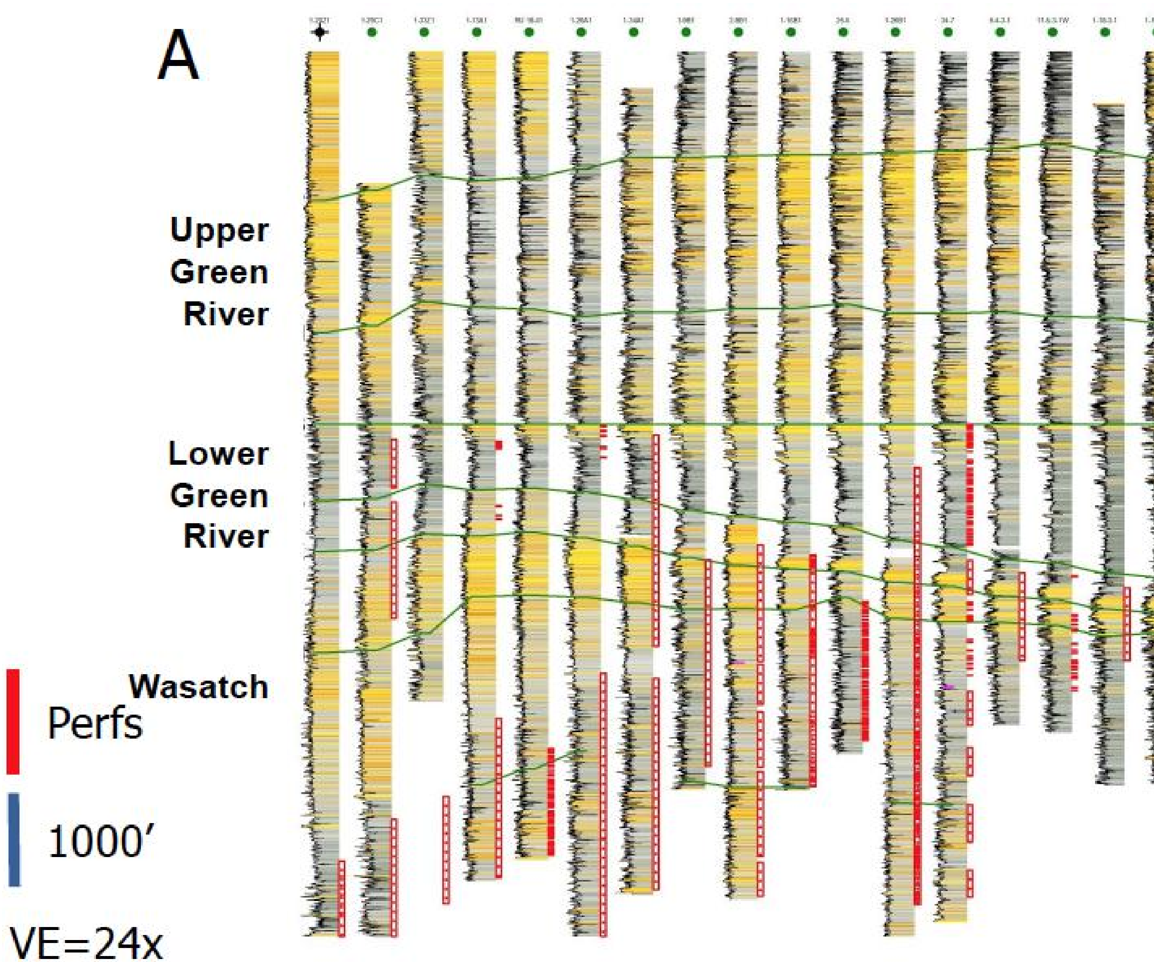
With the rebound in rig utilization and well drilling, oil-field service companies have begun to increase rig day-rates and frac costs. Use of more intensive development practices, such as longer laterals, greater number of frac stages, and higher volumes of proppant, will also raise well D&C costs.

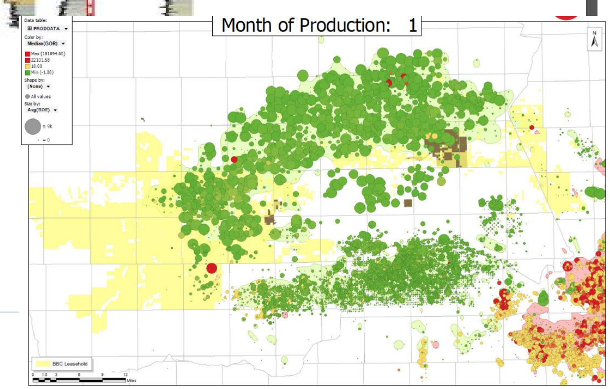
In contrast, improving efficiencies in days to drill a well, greater use of lower cost sand, and more competitive procurement of services will continue to help hold down these costs.

The question is - - *How will the combination of increased oil-field service costs, more intensive development practices, and improving well productivities drive future, say Year 2025, "tight oil" "break-even" costs?*

To address this, we again used five "tight oil" plays, one from each of the major "tight oil" basins. (These five plays are a sample from a larger set of 85 geologically distinct plays in these five "tight oil" basins.)

For Lacustrine- Hybrid Plays

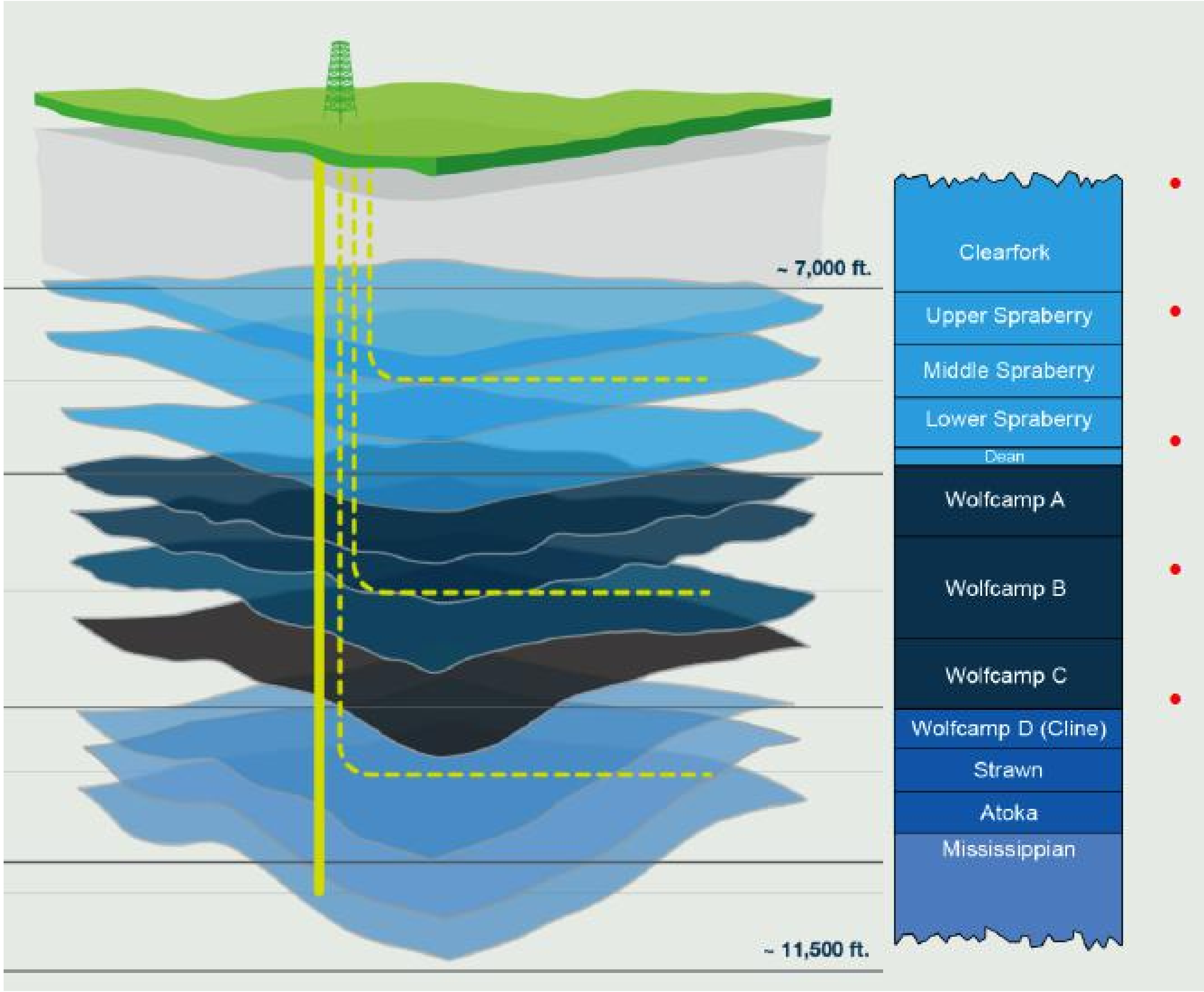




Uinta Basin in Utah

J. Rosink, 2013

Suggestions for China
Hybrid Pays Development



- Permian, Willinston Basins
-
-
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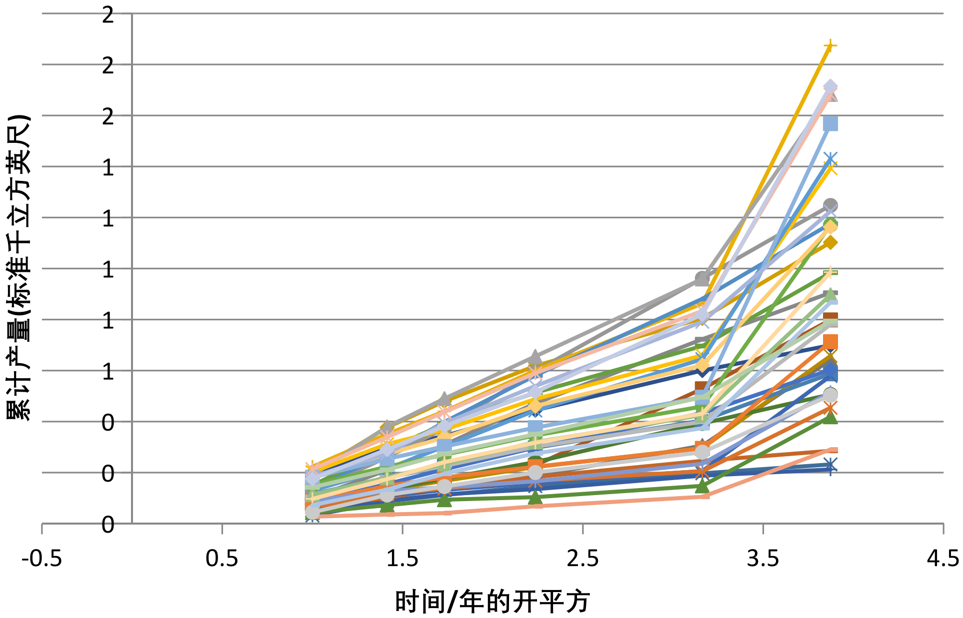
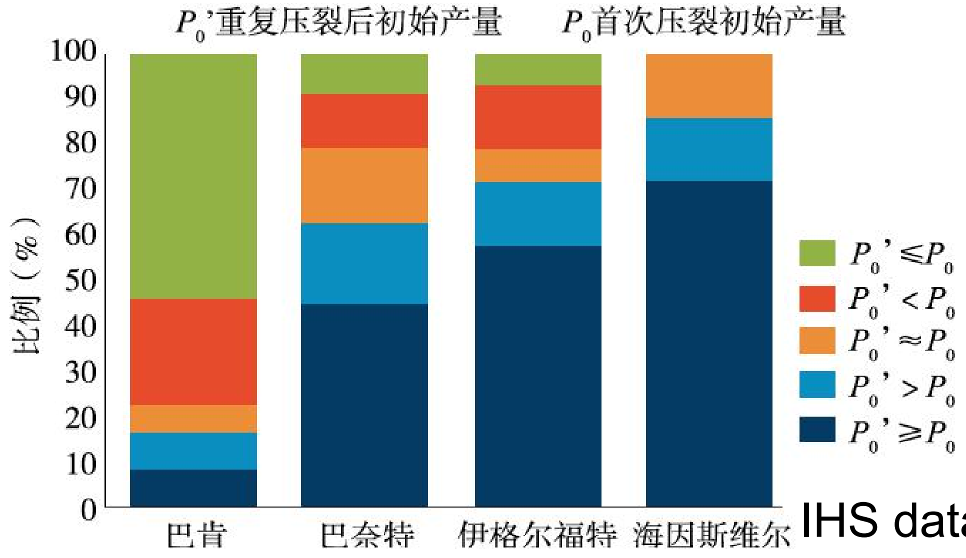
Refracturing



Barnett



IHS data

Learnings

- CBM, Tight Gas, Shale Gas, and Geothermal Energy are primary unconventional clean energy resources
- Geology + Engineering-Key for unconventional resources
- Organic rich shale-past source rocks to current reservoirs
- Geothermal energy-mainly direct use now. Power generation from conventional hydrothermal system, EGS experiment is ongoing