Hydrocarbon Migration and Trapping in Unconventional Plays*

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Abstract

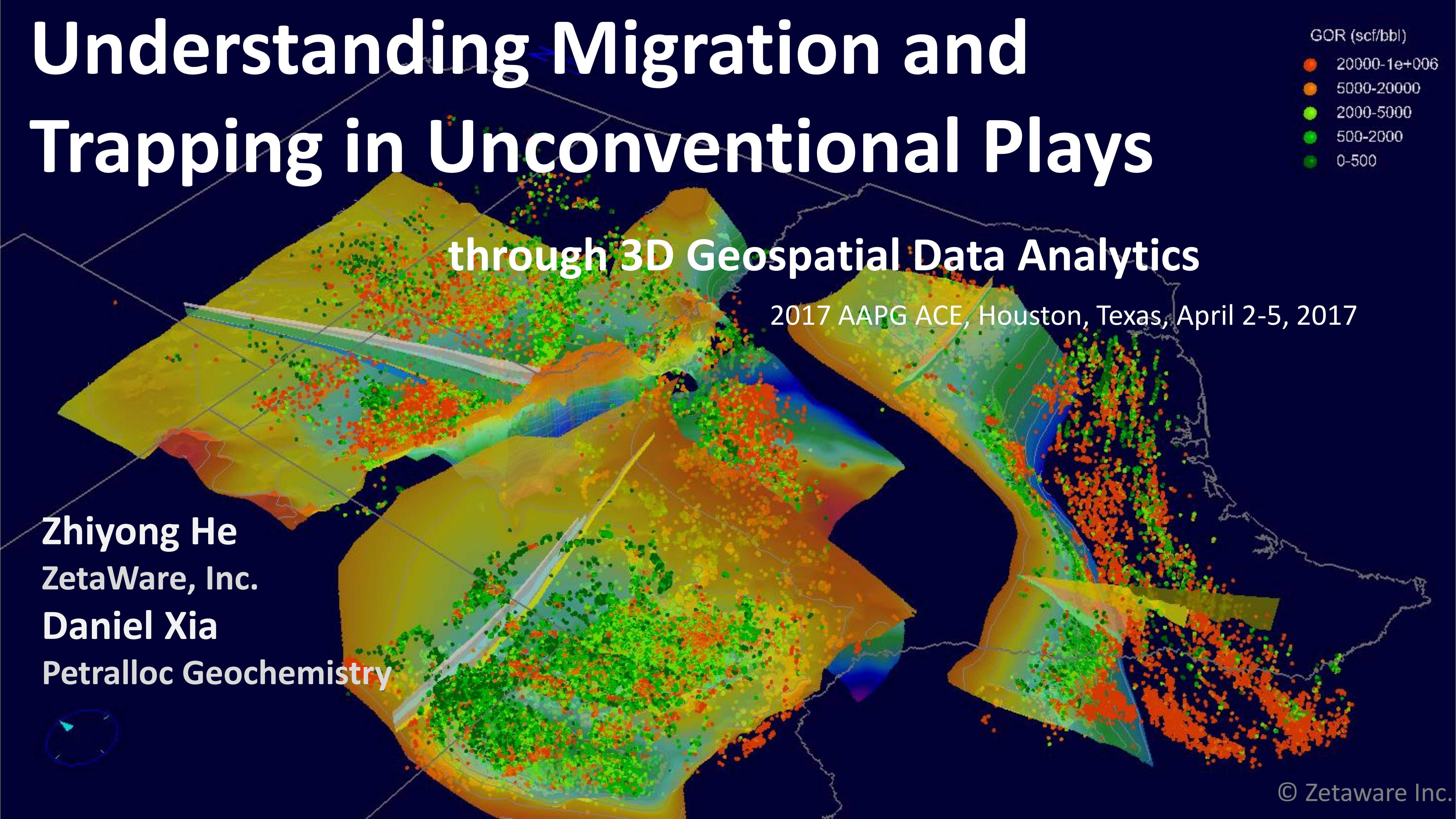
We will show in this presentation a collection of evidence for hydrocarbon migration at various scales in unconventional plays. This includes spatial variations in fluid properties (API, GOR, H_2S) which conform to structure, faults, and depositional facies boundaries, production of higher maturity fluids from low maturity, or immature strata, and production of different fluids from adjacent, or interlaced zones. Mixing and/or interlacing of high maturity and low maturity fluids due to differential migration often results in higher saturation pressure. This can lead to excessive gas production in an oil play or liquids drop out near the well bore in a gas play. Migration distances are estimated to be one to tens of kilometer laterally and hundreds of meters vertically.

Traditional sweet spot predictions have been mainly focused on source rock maturity. This may have led to incorrect predictions due to lack of consideration of migration as a factor. Companies who acquired leases based on maturity estimates alone have sometimes found themselves producing more gas than expected, and sometimes even dry gas from rocks currently in the “oil window”. We will also demonstrate that seals are very important and are a required element for unconventional plays to be successful. Homogeneous shales without sealing intervals will not retain sufficient hydrocarbons, even where maturity, TOC, porosity, and clay content, etc. are favorable. Exploration for unconventional plays therefore also needs to investigate structure, depositional environments and potential sealing units. In other words, the same evaluation criteria apply to conventional and unconventional plays, just at smaller scales in the latter case. In our examples, we analyzed data from ~ 2 million wells to recognize and demonstrate regional migration patterns in several basins.

Understanding Migration and Trapping in Unconventional Plays

through 3D Geospatial Data Analytics

2017 AAPG ACE, Houston, Texas, April 2-5, 2017



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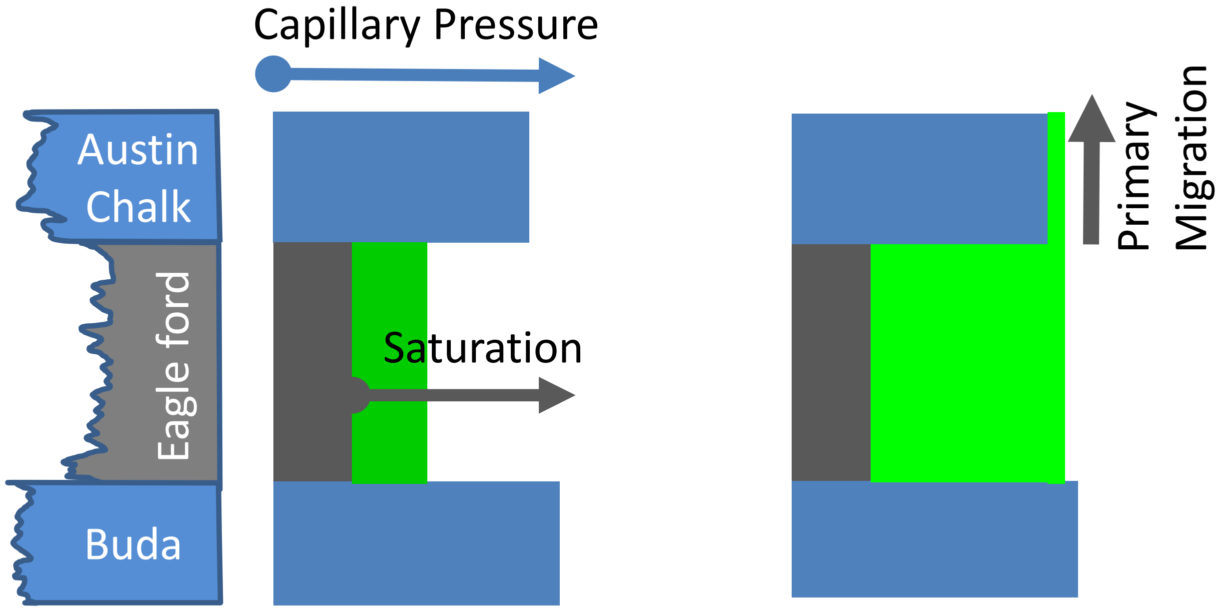
Introduction

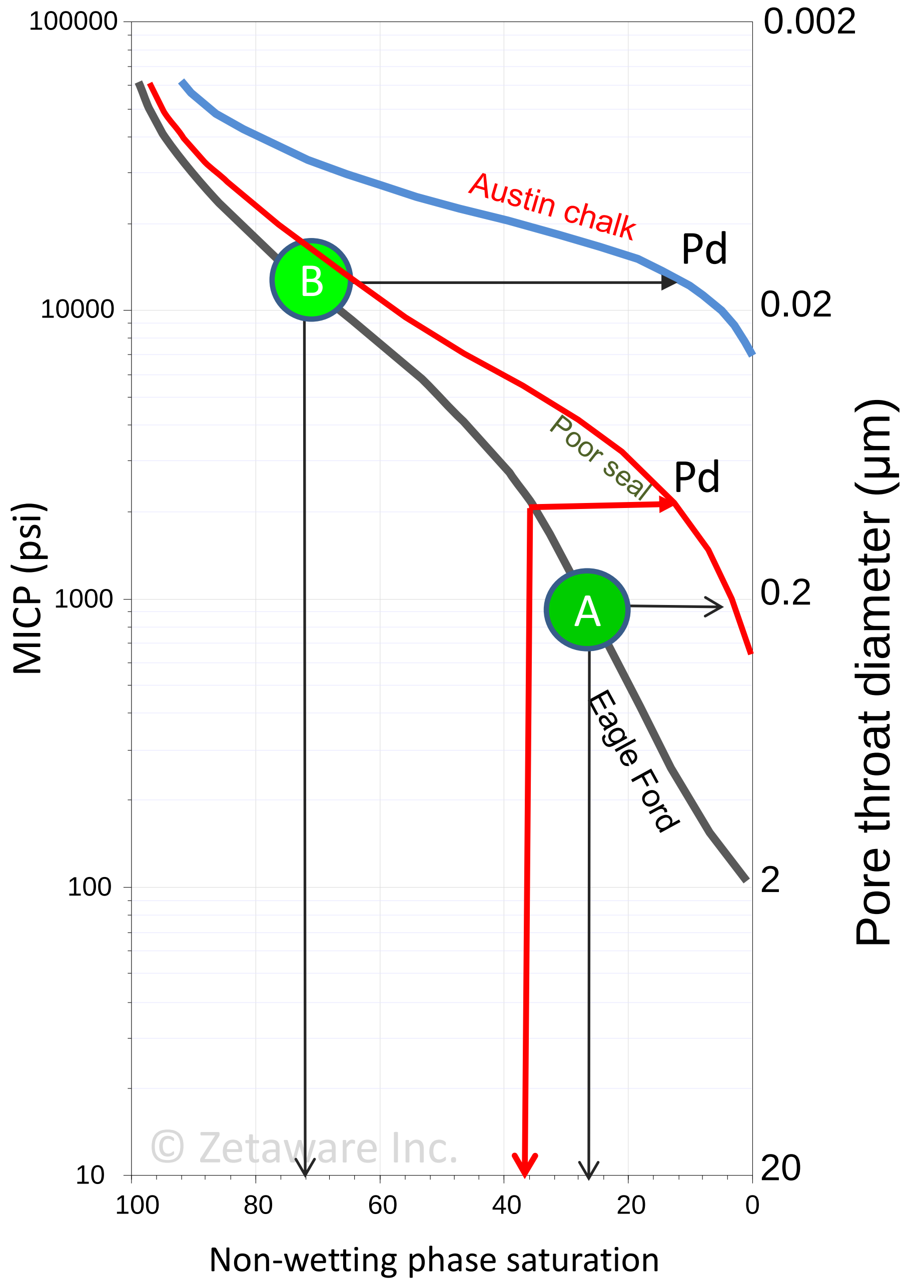
- Seals are required for trapping hydrocarbons, in both conventional and unconventional plays.
- Capillary displacement pressure of the seals control HC saturation in the reservoirs, as well as pressure, probably the two most important parameters in shale plays.
- This study utilized “Big data” (from ~2 million wells) to geospatially visualize and analyze the regional petroleum system behavior - migration patterns, regional seals, phase separation etc., ie “Geospatial Petroleum System Analytics - GPSA”
- 3D visualization of such data in the context of the geological framework is essential as many of the important patterns are stratigraphic and follows geological controls such as faults and facies boundaries.
- The results led to the understanding of several aspects of petroleum system in the region, previous unrecognized and or unappreciated.

Seals Control HC Saturation & Pressure



A 26% Saturation
900 psi MICP
56 psi Po-Pw

B 73% Saturation
13,000 psi MICP
800 psi Po-Pw



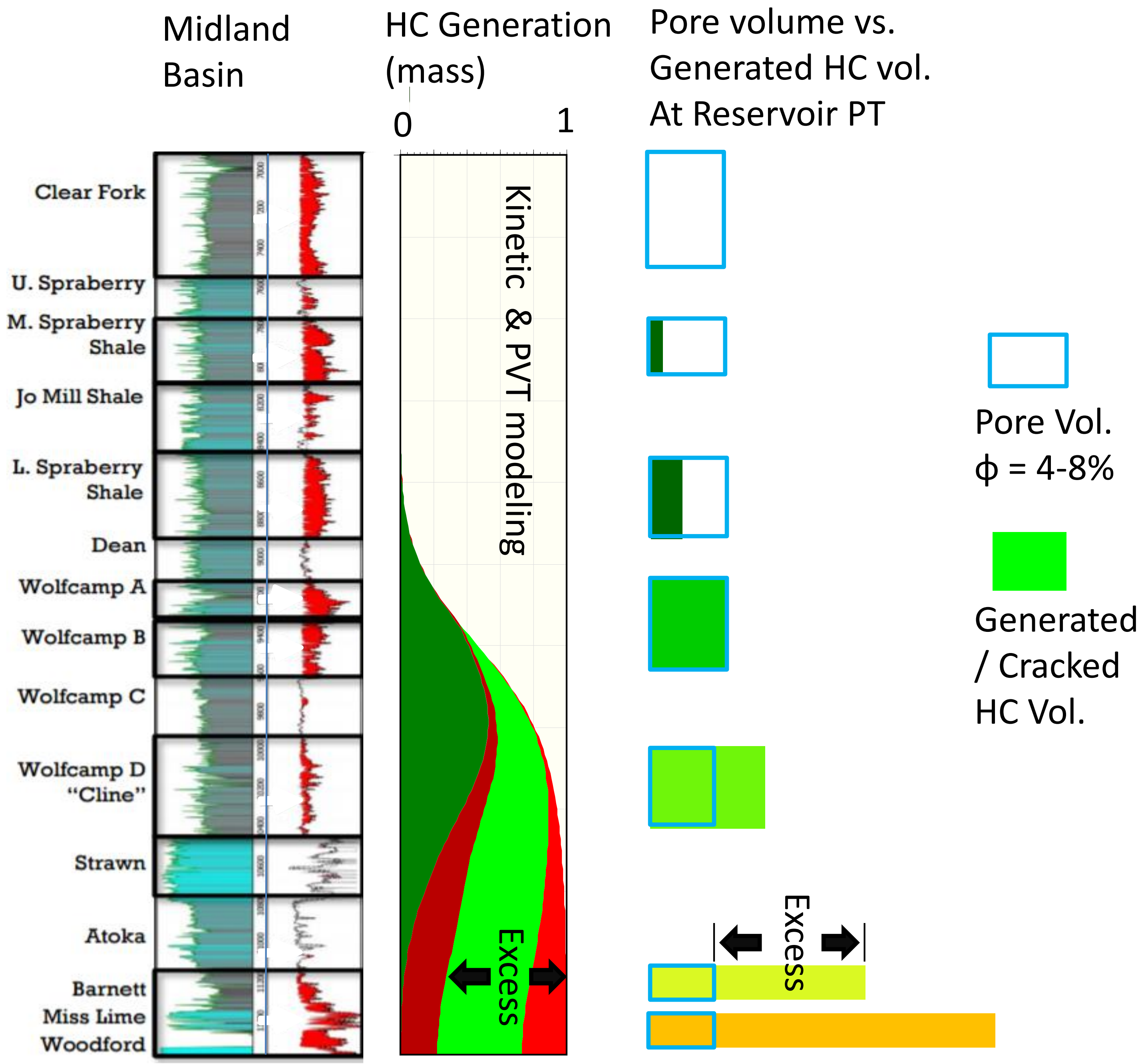
HC generation causes saturation and in turn capillary pressure (Po-Pw) to increase. Primary migration occurs when capillary pressure reaches the displacement pressure (Pd) of the seal. Higher Pd means higher retained saturation, as well as higher reservoir pressure. This is a generalized/idealized model – most systems are more heterogeneous but the principles are the same.

Migration in the Stacked Shale Plays:

At higher maturity, generated HC volume at reservoir PT conditions is 3-5 times the available pore volume as HC density decreases from 0.6-0.8 g/cc (low to moderate GOR oil) to 0.1 to 0.2 g/cc (for gas condensates). The excess volume of HC is forced to migrate up stratigraphy and/or up dip.

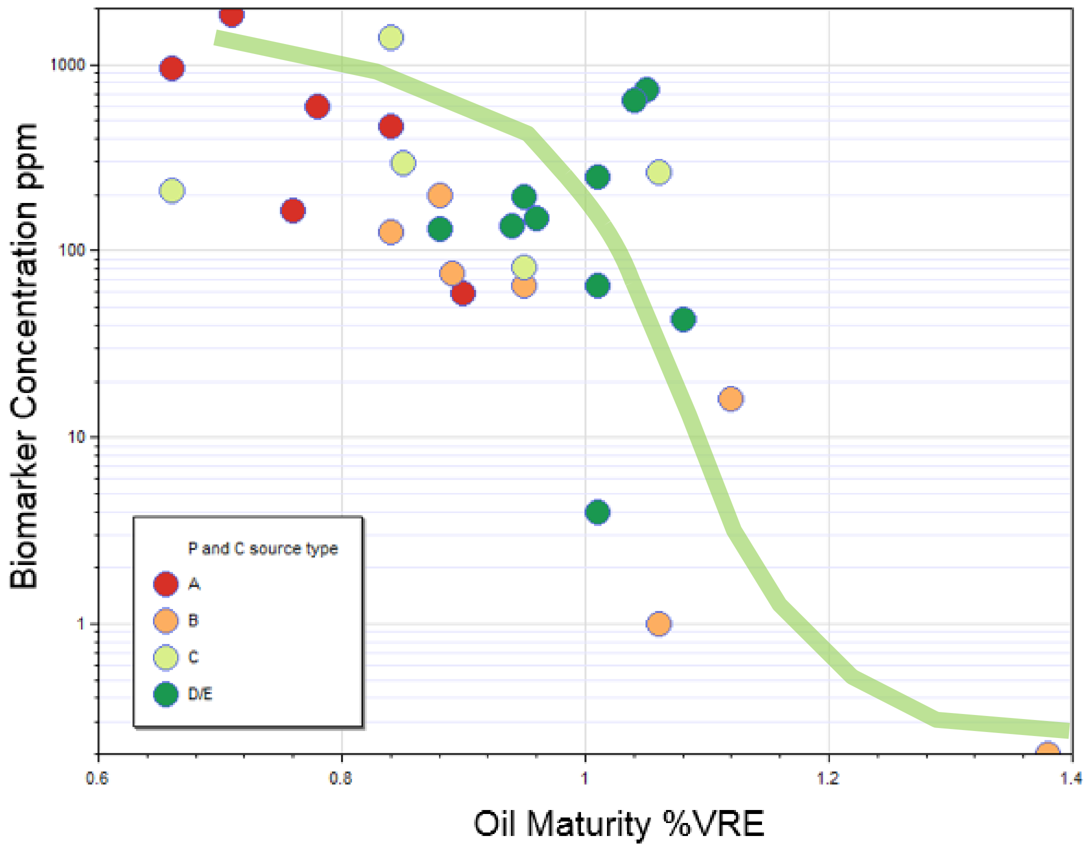
For example, the Wolfcamp may contain a mixed fluid of local generated oil and gas condensate from deeper source rocks (Barnett, Woodford etc.).

Spraberry/Bone Spring/Clear fork reservoirs are filled mostly with migrated fluid.



Effects of Mixing Oil with Gas Condensate in Subsurface

When locally generated low maturity oil is mixed with equal volume of migrated gas condensate in subsurface conditions, GOR more than doubles, but oil API gravity increases only by about 10%. Biomarkers & ratios are not affected at all. Incompatible GOR and API gravity is a sign of mixing. This can result in higher bubble point pressure and cause in-situ phase separation – and production of gas in oil maturity formations.



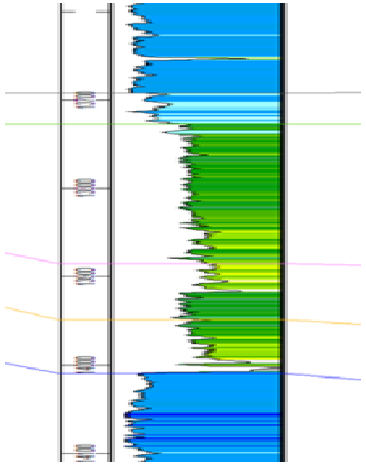
	GOR (scf/bbl)	API Gravity	BM Maturity % VRE
Local Oil	1000	35	0.8
Gas condensate	10000	55	1.2
Mixed:	2700	39	0.8

Observations:

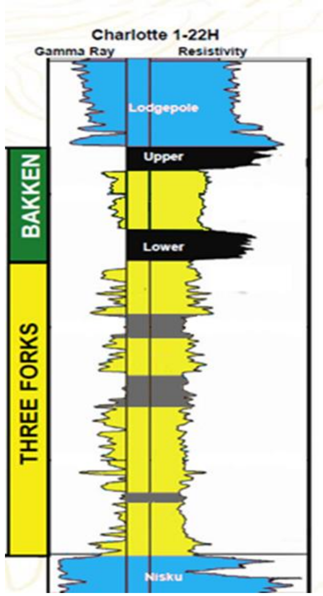
- API gravity reflects source rock maturity trend better than GOR.
- Produced GOR typically higher than maturity model “predicts”.

Reservoir and Seal Pairs for Major US Liquid Plays

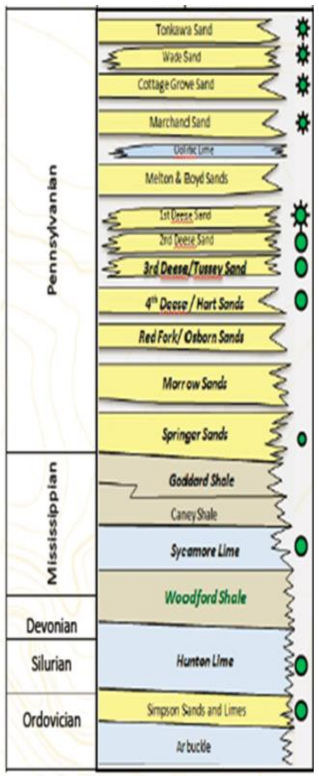
Eagle Ford



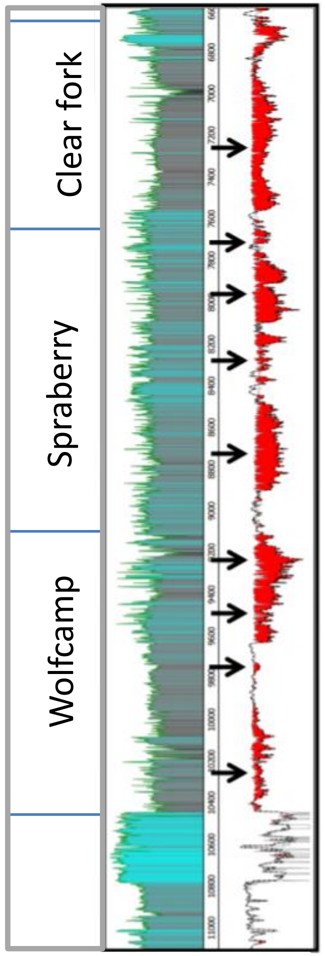
Bakken



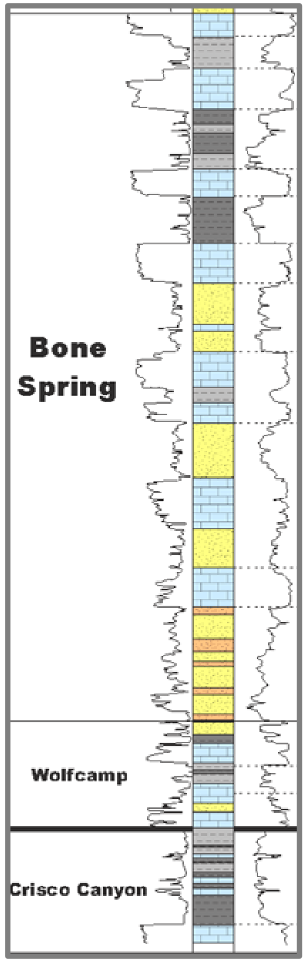
Woodford



Midland



Delaware



Typical shale plays are interbedded limestone, shale, and siltstones. Pay (reservoir) can be within, above, below or in between the source intervals.

Sources: Pioneer, Matador, Continental Resources, ShaleExperts.com, Ajit K. Sahoo et al

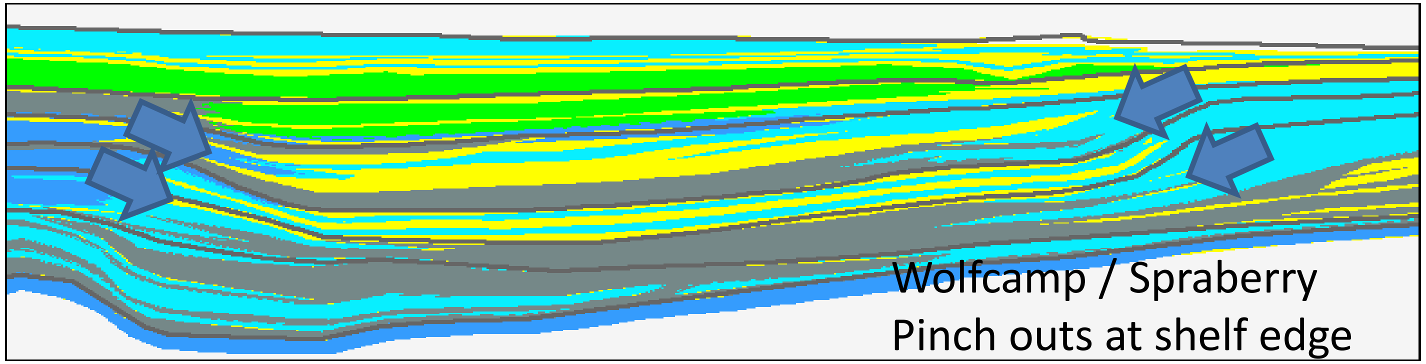
Top and Bottom Seals of Major Shale Plays

	Reservoir	Top Seal	Bottom Seal
Eagle Ford shale	Eagle Ford marl	Austin Chalk	Buda limestone
Marcellus shale	Siliceous shale	Tully limestone	Onondaga limestone
Bakken	Middle Bakken, Tree forks siltstones.	Lodgepole limestone	Nisku limestone
Woodford	Siliceous shale	Mississippi/Osage limestone	Hunton limestone
Meramec	Calcareous shale	Chester shale/lime	Osage limestone
Barnett	Siliceous shale	Marble falls/Forestburg limestone	Chappel/Viola limestone
Haynesville	Marls	Interbedded limestones	Smackover lime
Niobrara	Marls/sands/chalk	Interbedded shales/Chalk	Fort Hays limestone
Spraberry, Bone Springs	Sandstone & siltstones	Interbedded limestone	Interbedded limestone
Wolfcamp	Marls, silts	Interbedded limestone	Interbedded limestone

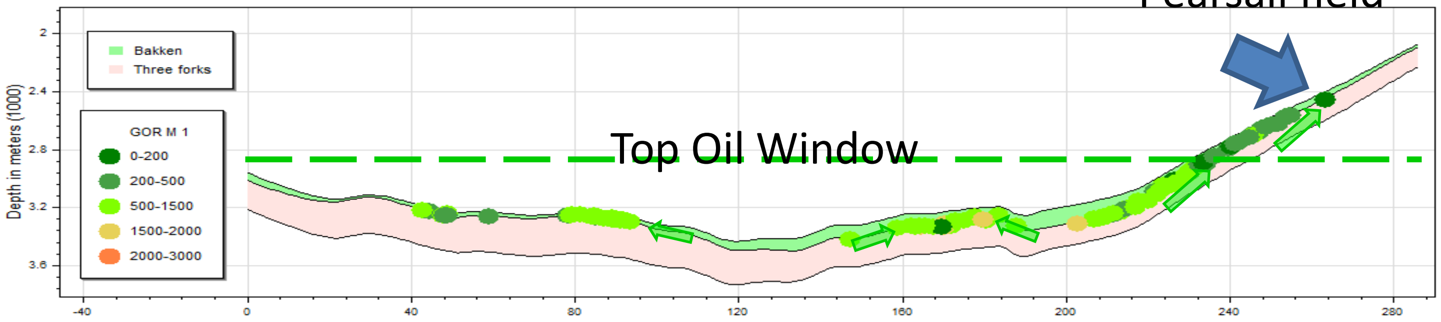
The general observation is that majority of working shale plays are marl/shale/silt reservoirs sandwiched in between limestone units. Limestones are likely (not necessarily exclusively) the master seals for these plays?

Examples of Lateral Seals/Trapping

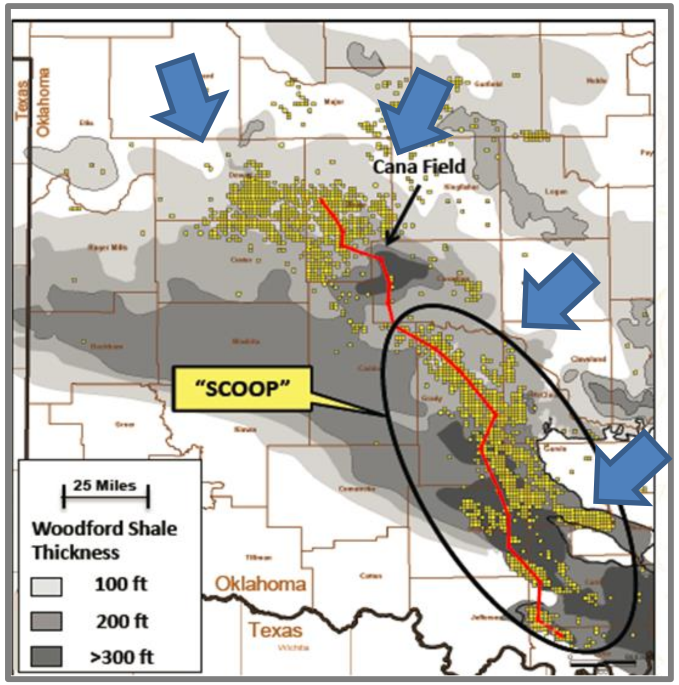
Midland Basin

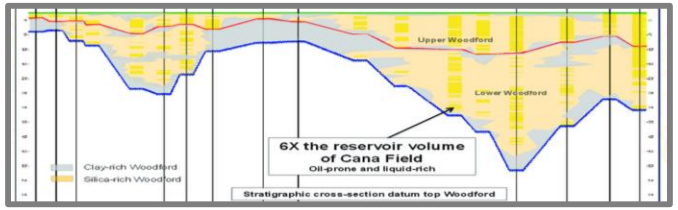


Williston Basin



A geological definition of unconventional plays may be simply “stratigraphic traps”, that require fracking to be economical?



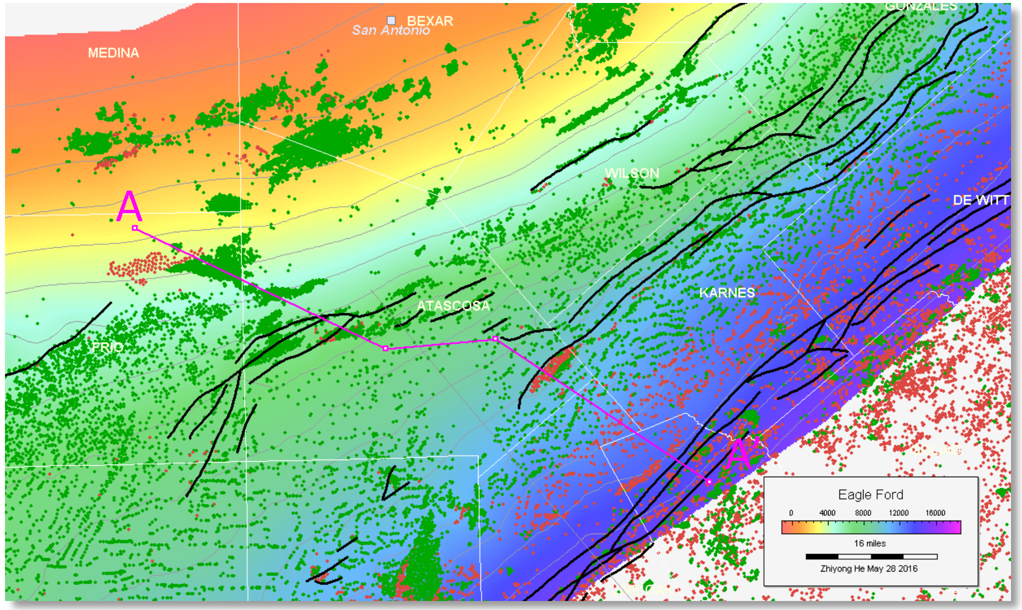


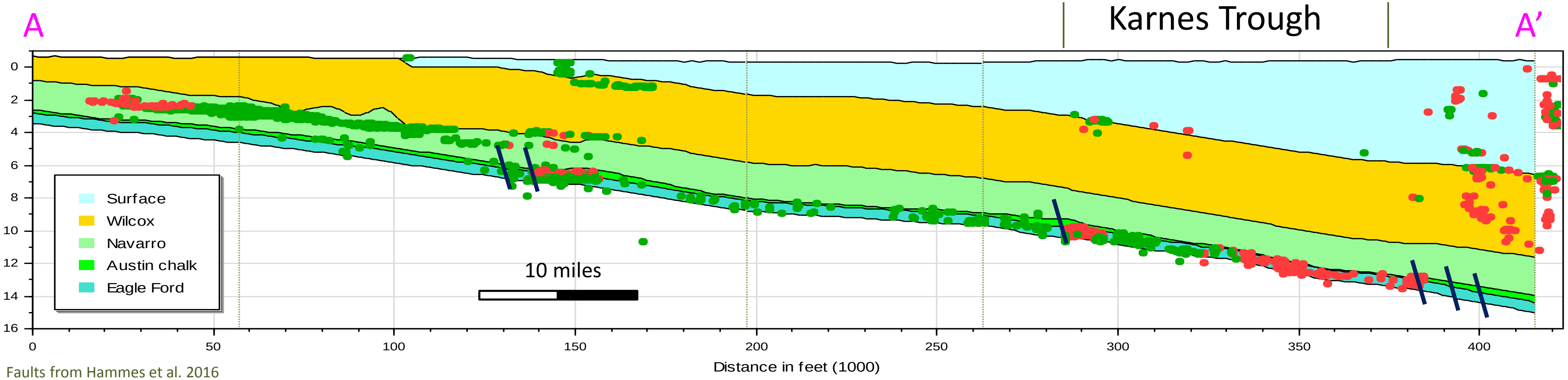
Woodford shale isopach, Anadarko basin

Source: Continental resources

Faults Provide Lateral Trapping In Eagle Ford ?

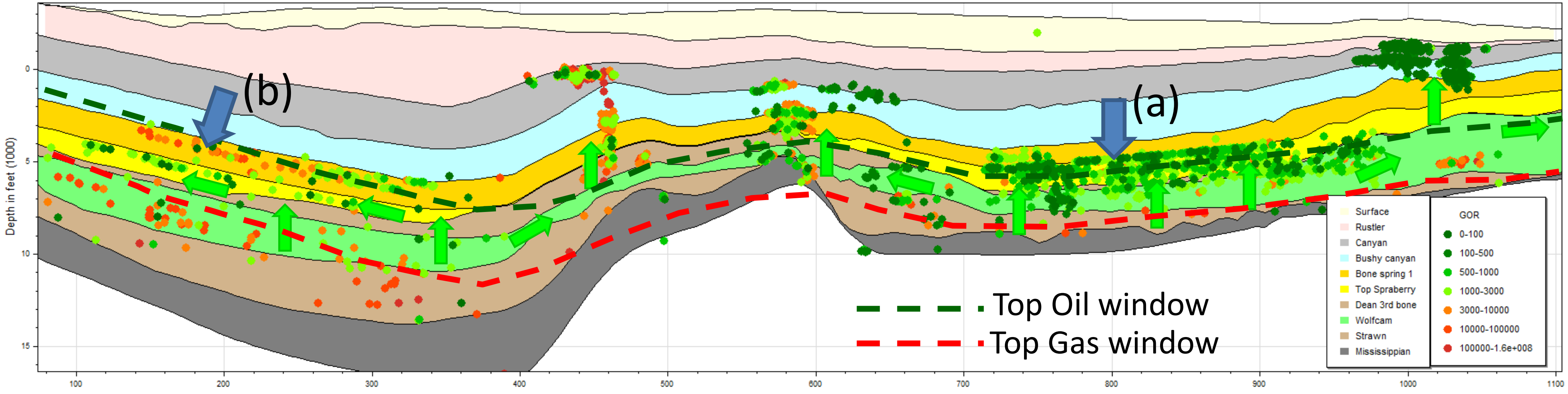
- ❑ Sweet spots down dip from and in between major faults.
- ❑ Migration shadows up dip from faults
- ❑ Stepping up stratigraphy up dip from faults
- ❑ "Gas caps" observed
- ❑ Better IP rates on down thrown side of faults (Drilling info)





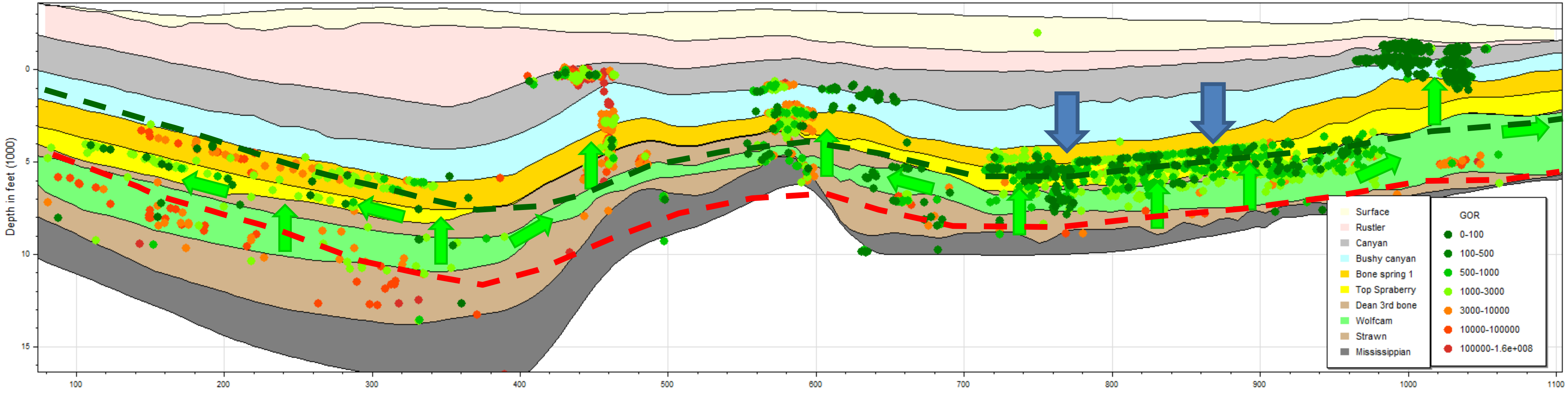
Faults from Hammes et al. 2016

Geological Controls on Fluid Migration



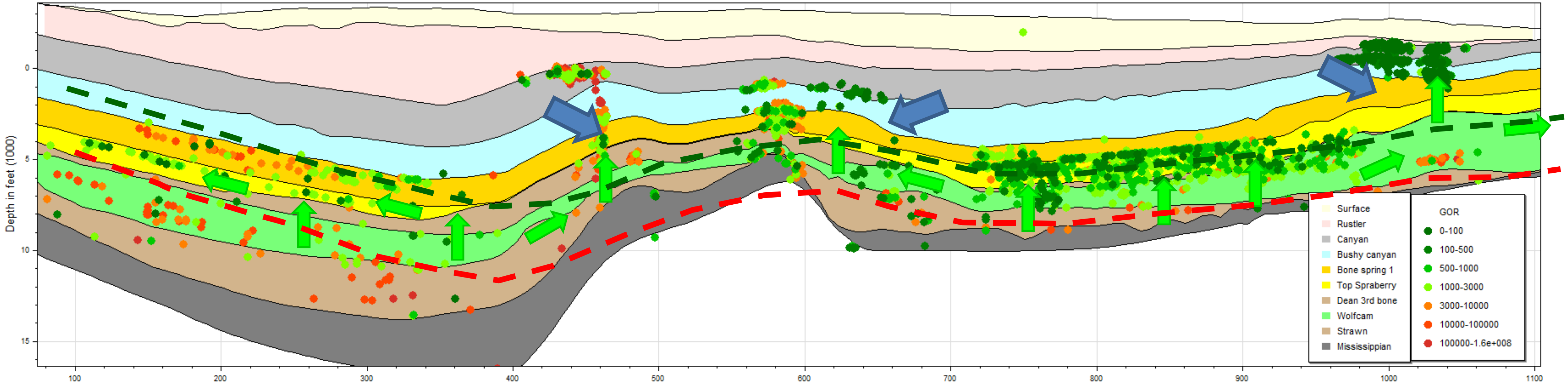
Oil production above oil window (a) and gas production in oil window (b), with higher than expected GORs for the measured or modeled maturity. Expected GOR (<500 scf/bbl) at the low maturity is much lower than observed (1000-2000 scf/bbl).

Geological Controls on Fluid Migration



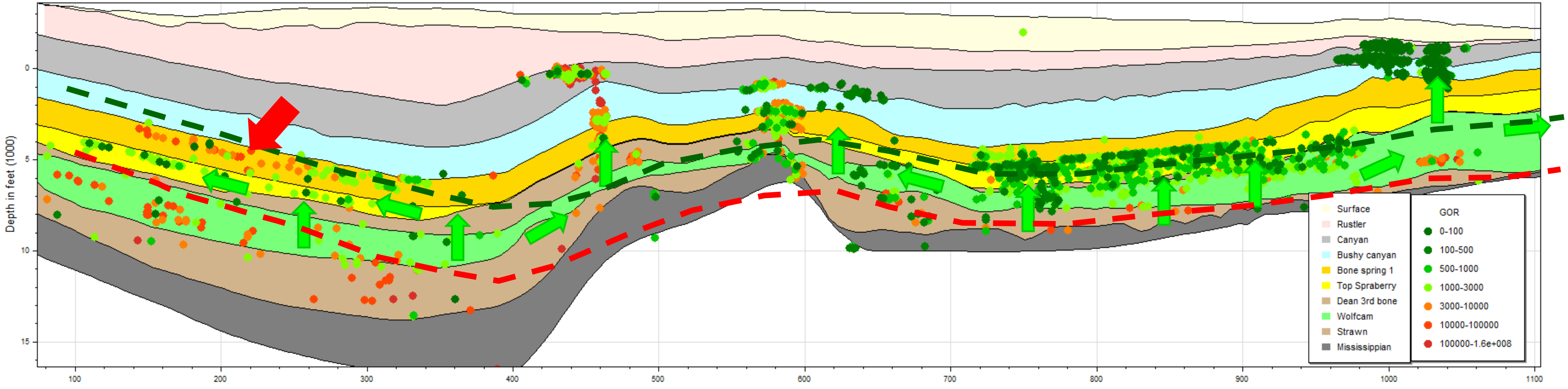
Good top seal in deeper basin: The silty reservoirs of the Spraberry and the overlying deep water calcareous facies present a good contrast for sealing/grapping mechanism. The lack of structure relief may also be a factor. Wolfcamp zones may be productive where it is overlain by limestone zones.

Geological Controls on Fluid Migration



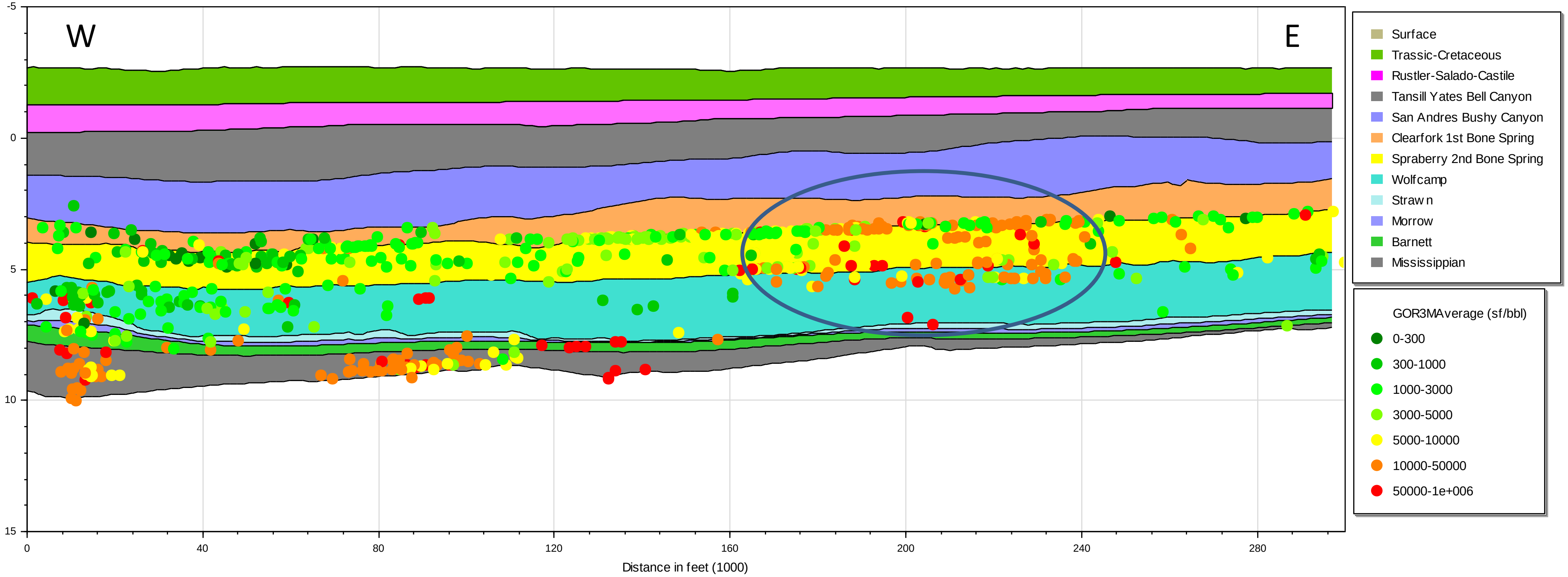
Significant vertical migration occurs at shelf edge where deep reservoirs or seals may be truncated due to facies change and/or faults.

Geological Controls on Fluid Migration



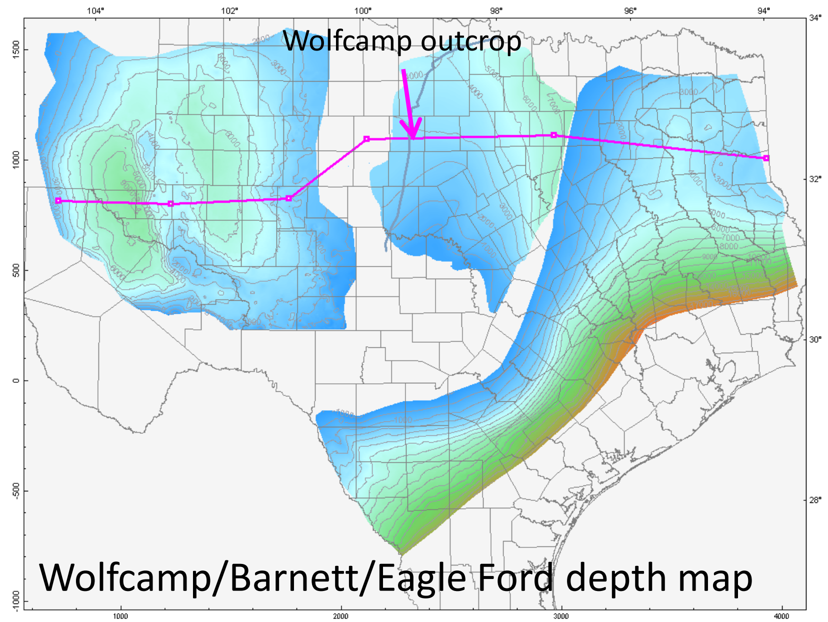
Phase separating due to fluid mixing? High maturity gas condensate may have migrated into shallow reservoirs to mix with locally generated oil. Pressure is below bubble point pressure for the mixture and phase separation occurs and forms “gas cap”. Such gassy areas may expand downdip over time as production further draws down pressure.

More Evidence of Upward Migration & Mixing

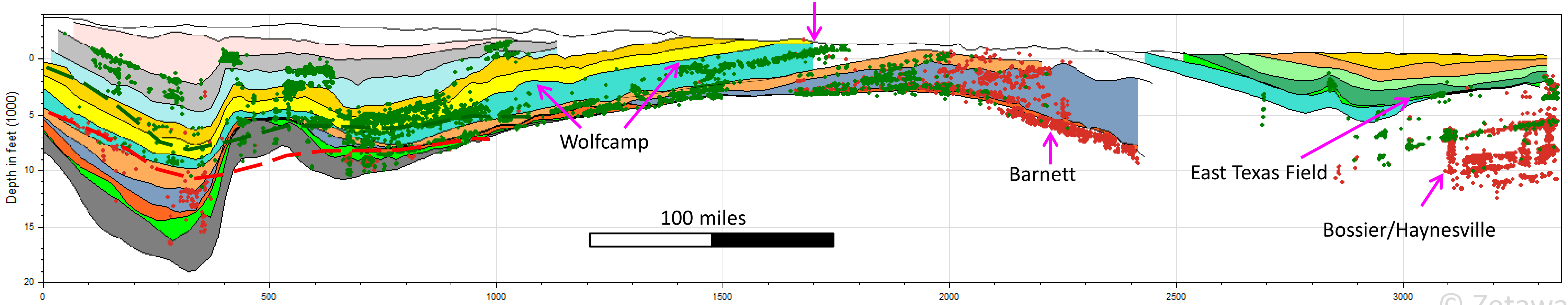


Vertical migration of gas condensate seem to have affected a significant area in the Midland basin. The Spraberry (yellow) is in early oil window maturity. The produced fluids seem to have relatively low API gravity for the high gas oil ratio (5,000 to 20,000 scf/bbl).

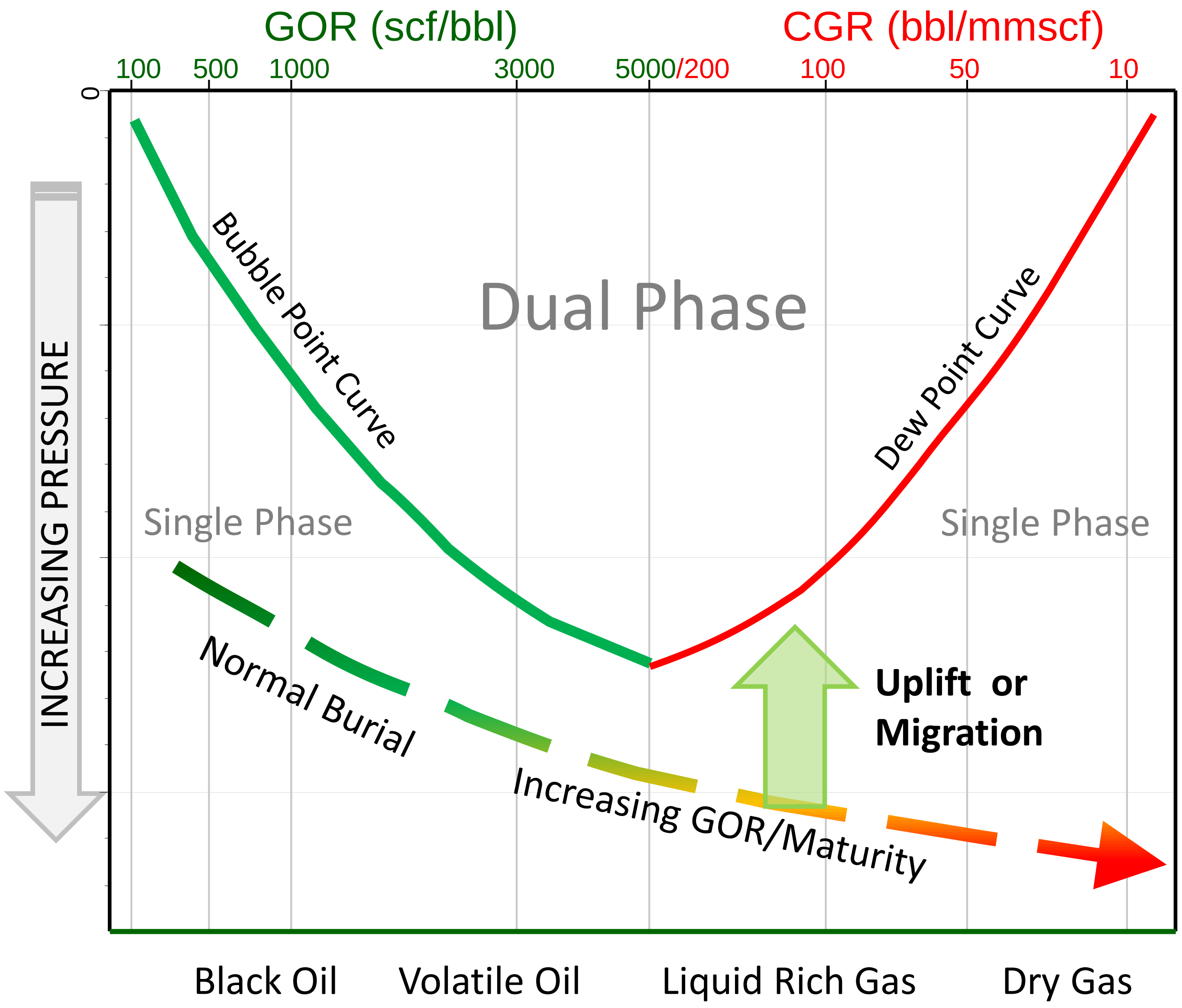
Long Distance Migration ?



- ❑ Wolfcamp only matures in the deeper part of Midland basin.
- ❑ Oil may have migrated from Midland basin over to the Fort Worth basin > 100 miles.
- ❑ Production from the Spraberry, Bone Springs, Brushy Canyon, Avalon formations are mixed with fluids from Wolfcamp, and/or Woodford.
- ❑ "Gas caps" observed in several plays.
- ❑ Vertical migration near Permian shelf edge where deep water reservoirs pinch out against carbonates.



The Natural PVT Model

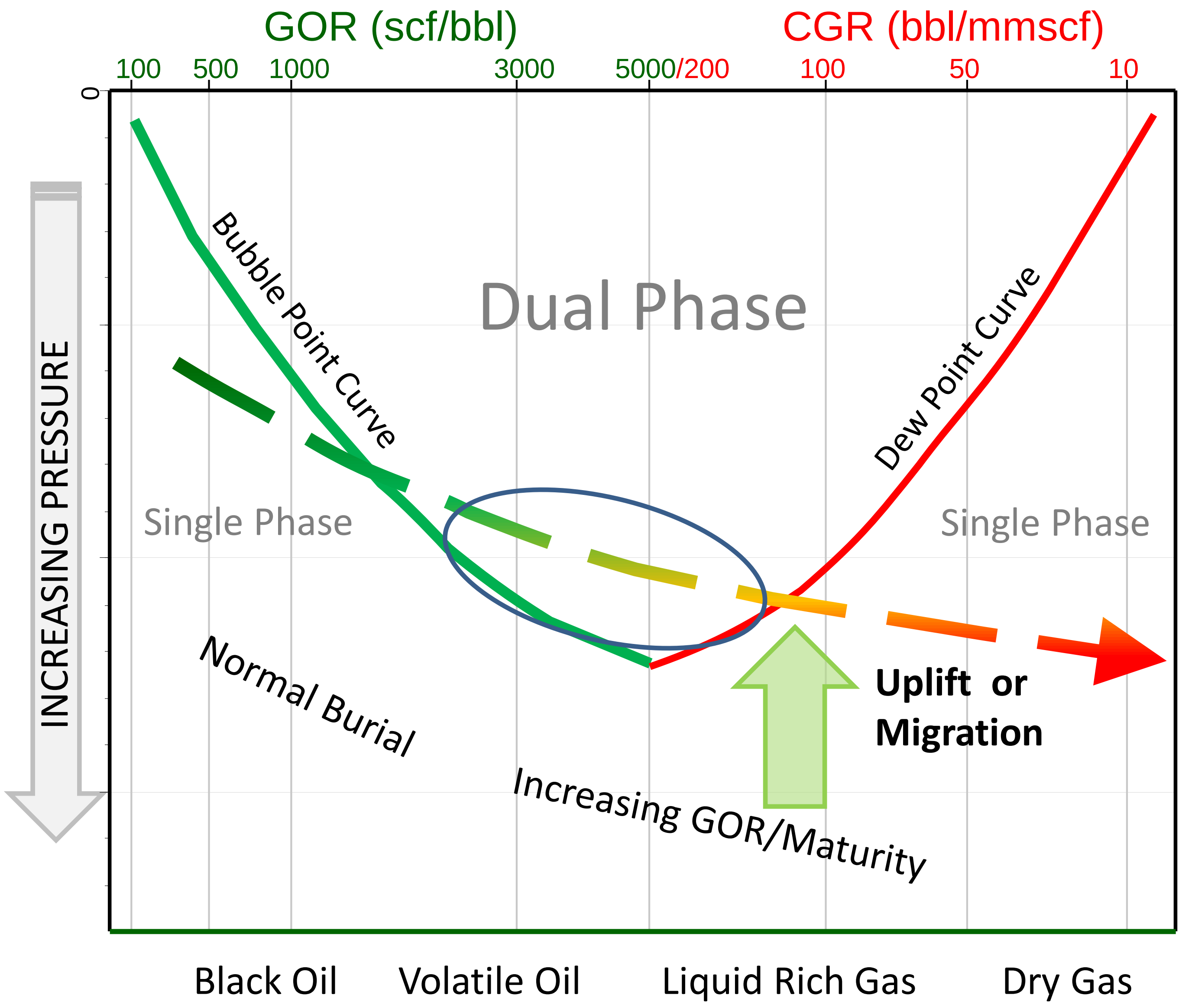


1) During the burial and generation process, the depth and pressure increase as maturity, and gas oil ratio increases. Due to increasing pressure the fluid is naturally single phase.

2) Pressure drop due to uplift or migration into shallow reservoirs may cause fluid to become dual phase (gas exsolves from oil to form vapor phase at reservoir pressure).

3) Mixing high maturity gas with low maturity oil can increase bubble point pressure to above reservoir pressure, giving a similar effect.

The Natural PVT Model



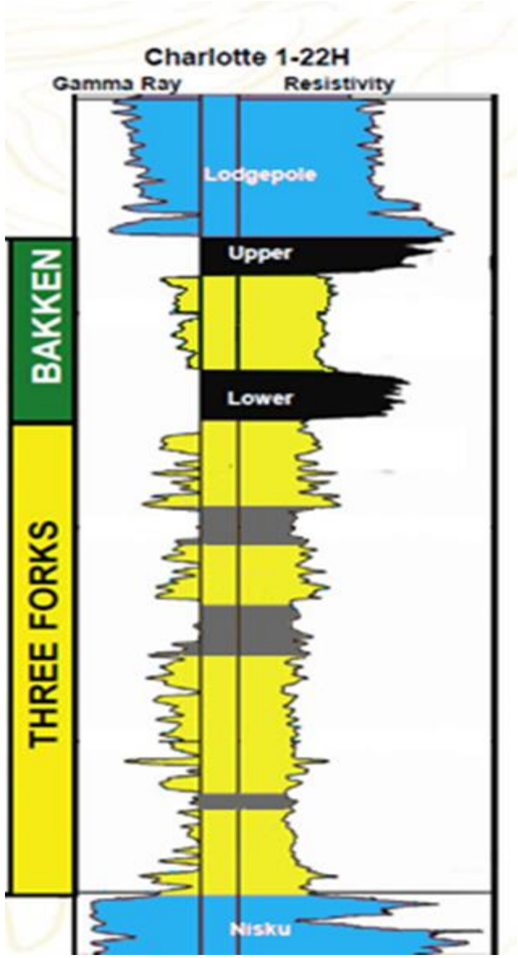
1) Separate gas and oil phase causes higher gas production and GOR increases over time as pressure declines.

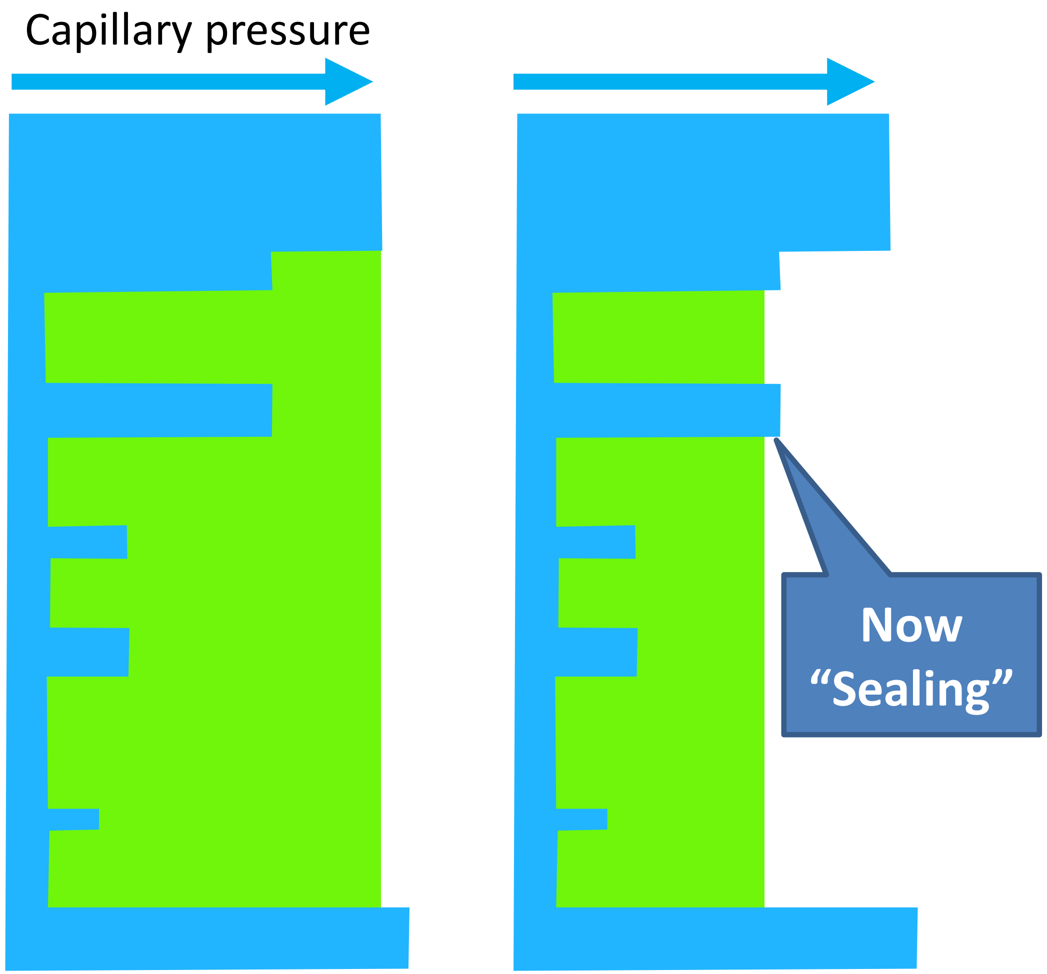
2) Regions where reservoir is near bubble point may initially produce oil, but soon becomes gassier.

3) Volatile oil region with significant erosion, or gas migration into low maturity oil = higher risk for phase separation.

4) Low maturity oil window and gas window (CGR>100 bbl/mmcf) are less affected by phase issues.

Intermediate Seal Becomes Effective During Production





(a) (b)

Intermediate seals may "become" sealing during production once pressure drops below its displacement pressure (Pd).

(a) Initial pressure at Pd of main seals. Two reservoirs are in pressure communication.

(b) During production, pressure drops below Pd of intermediate seal. Oil phase now snapped and disconnected.

Some Important Observations

- Several of the stacked systems seem to show a pattern where if the upper reservoir performs well, the lower reservoir is less productive, and vice versa, the Austin Chalk vs the Eagle Ford, Spraberry / Bone Spring vs the Wolfcamp, and Clear Fork vs the Wolfberry system. In one example, the Chester shale, which is recognized as a seal for the STACK play in Anadarko basin, is eroded to the north where water oil ratio is higher in the underlying reservoirs.
- The sweet spots of the younger play tend to be offset to the up-dip direction of the lower play – indicating migration up stratigraphy where the lower reservoir pinches out or lacks sealing capacity. Younger conventional reservoirs are mainly found outside of the main kitchen in the Permian basin. Such relationships are very clear when production data are visualized in 3D in the stratigraphic context.
- Significant conventional accumulations may be found up to 300 miles up dip from the source kitchen of the unconventional reservoirs, such as the oils in Kansas and Nebraska that have migrated from the Anadarko basin in Southern Oklahoma, and oil accumulations near Fort worth in the Wolfcamp formation that may have migrated from the Midland basin.
- Along major trends/fairways of long distance migration, the near kitchen plays are more gassy – perhaps because the increased efficiency allows oil to migrate further.
- Migration and/or uplift may cause reservoir fluids to go below bubble point pressure, resulting dual phase reservoirs may produce fluids with significantly higher gas oil ratios.

Conclusions:

- It is important to also consider seals in searching for the next unconventional play. Capillary seals help retain saturation in the reservoirs.
- Seals are simply rock layers with smaller pore throat size than the reservoirs. For conventional reservoirs, seals are typically shales. But for shale reservoirs, they may be typically limestones and may often be a stack of interbedded reservoirs and seals, at different scales.
- Limestone formations seem to be regional top and bottom seals for most productive shale reservoirs. Some plays may be described as self-sealing as the reservoirs are highly stacked sequence of silt/shale/marl/limestones. Shales and other rock types can be seals as long as the pore throat size is smaller than that of the reservoir.
- <u>*Point of likely misunderstanding: Seals do not imply no migration at all. Capillary seals are exactly like pressure valves, bleeding off excess fluid while retaining a full capacity of the reservoirs. Maximum HC Saturation depends on the difference in capillary displacement pressure of the seal and the reservoir pore size distribution.*</u>
- Lateral seals for shale reservoirs are typically facies changes, and sometimes faults. Structure relief/focusing can also be important. Viscosity at low maturity front may also be effective (?).
- Migration is observed at different scales. Therefore, unconventional play targets do not have to be the source rock. Potential reservoirs can be above, below or up dip from the mature source rock, or highly interbedded reservoir/seal packages. The potential reservoirs may not be limited to areas where the source is mature.

THANK YOU!

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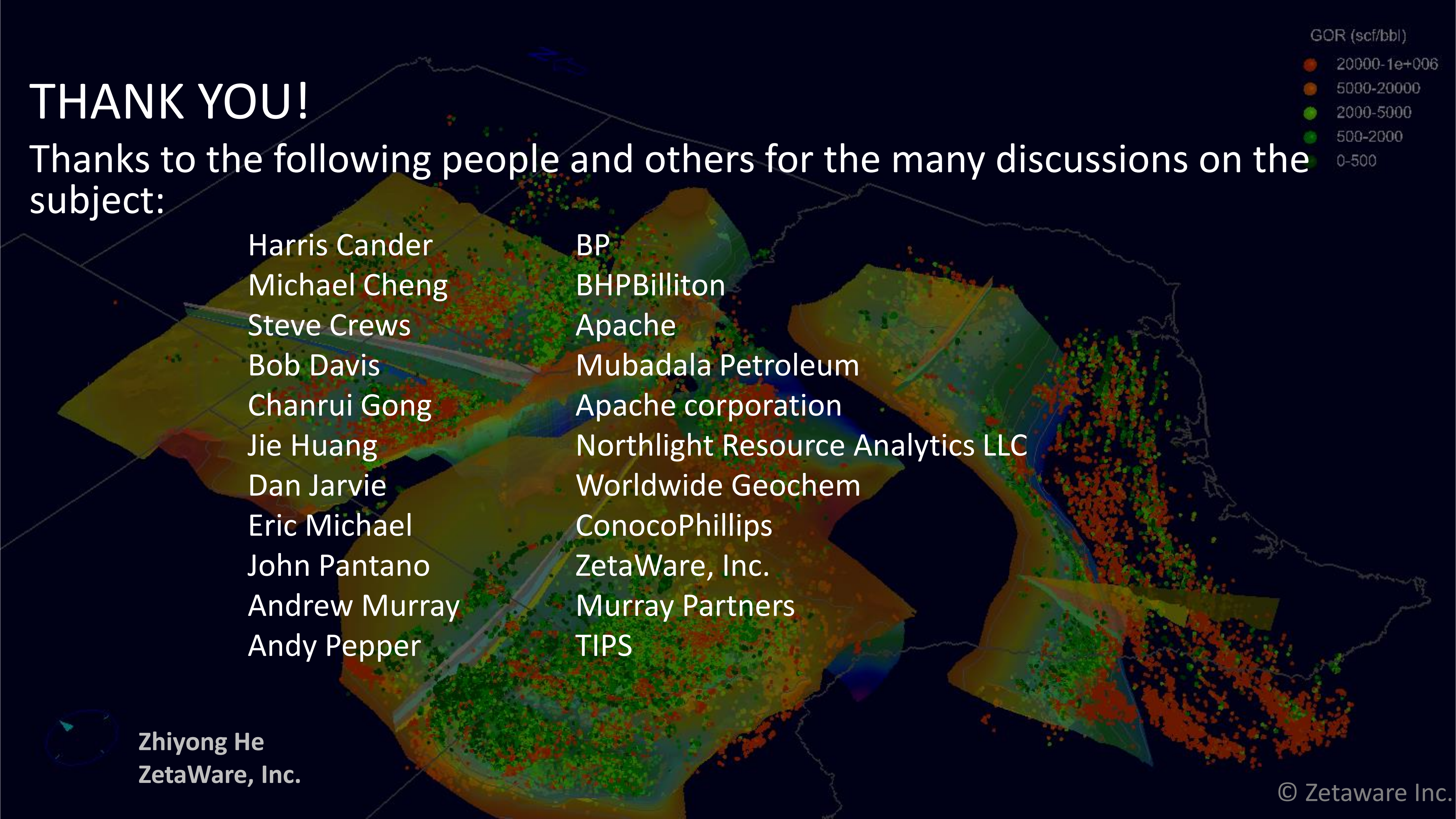

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