Pore Characterization and Geologic Controls on Matrix Permeability of the Eagle Ford Shale*

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Abstract

Permeability measurements were obtained on 24 intact plugs from two wells of different thermal maturity in the Eagle Ford in South Texas. Ten plugs were taken from a low thermal maturity (Ro = 0.62) well, and 14 from a high thermal maturity (Ro = 1.45) well. Thin sections and x-ray diffraction data were obtained for all samples from plug end-trims. The permeability of the marls (defined as having <35% clay and 35–65% carbonate by volume) which is on the order of 1 to 100 nD, was observed to increase with increasing calcite volume in laminations, but no fractures were observed in any of the marl samples. The high permeability (>200 nD) of the limestones (defined as having >65% carbonate by volume) was also seen to increase with increasing calcite volume, reflecting an increasing volume of fractures. Scanning electron microscope (SEM) microscopy of the plugs used for permeability measurement and lower-maturity outcrop samples (Ro = 0.4) shows that all of the intergranular pores in the Eagle Ford, regardless of TOC, mineralogy or facies, contain hydrocarbon. The lowest maturity outcrop samples contain viscous bitumen migrating through pores, while thermally mature samples are filled with solid hydrocarbon, identified by visual kerogen analysis and solvent extraction as both bitumen and porous pyrobitumen. This solid organic matter effectively occludes primary pores like a diagenetic cement. The thermally-mature organic-matter cement is porous, but permeability is not directly related to the total organic carbon content. Most of the fractures in the limestone are the result of coring (do not contain either mineralization or solid hydrocarbons) but nonetheless illustrate the presence of a connected pore system once fractures form during the process of hydraulic fracturing. Fractures that are present in situ (contain mineralization and solid hydrocarbon) would be activated by hydraulic fracturing. The Eagle Ford is therefore a dual-porosity system, with matrix storage feeding a network of progressively larger natural and induced fractures that carry hydrocarbons to the wellbore. The importance of choke management in the Eagle Ford, in which both matrix and natural fractures have stress-dependent properties, including permeability, is illustrated.

Selected References

Breyer, J., R.H. Wilty, Y. Tian, A. Salman, K.W. O'Connor, B. Kurtoglu, R.J. Hooper, R.M. Daniels, R.W. Butler, and D. Alfred, 2015, Limestone Frequency and Well Performance, Eagle Ford Shale (Cretaceous), South Texas: AAPG/STGS Geoscience Technology Workshop, Fourth Annual Eagle Ford Shale, San Antonio, Texas, March 9-11, 2015, Search and Discovery Article #51091 (2015). Website accessed July 2017.

Kosanke, T.H., and A. Warren, 2016, Chapter 8: Geological Controls on Matrix Permeability of the Eagle Ford Shale (Cretaceous), South Texas, U.S.A.: American Association of Petroleum Geologists Memoir 110, The Eagle Ford Shale: A Renaissance in U.S. Oil Production, p. 285-300.

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Pore Characterization and Geologic Controls on Matrix Permeability of the Eagle Ford Shale

Tobi Kosanke

With contributions from John Breyer, Richard Denne, Richard Rosen and Anne Warren

ALS Oil & Gas

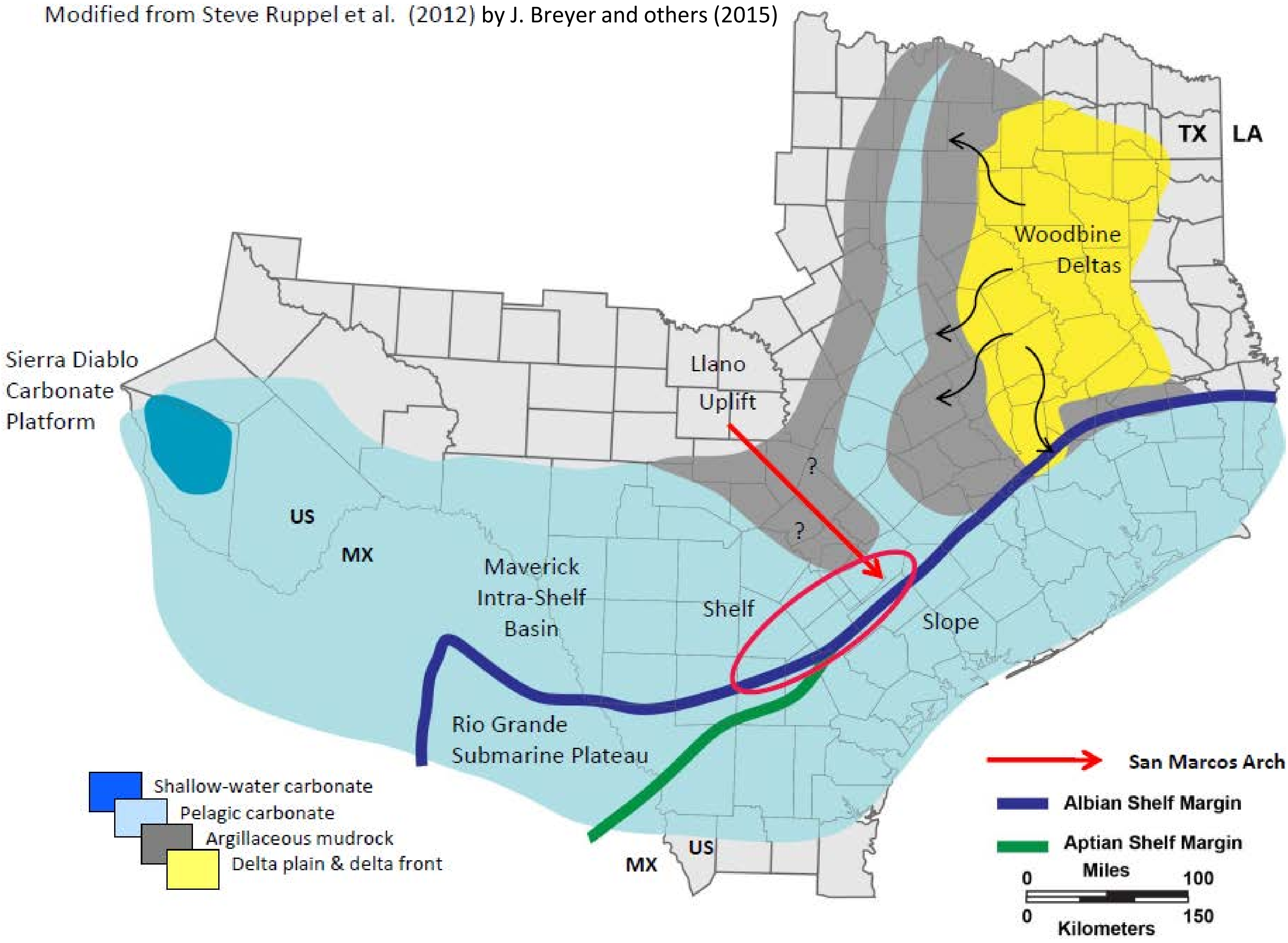
Summary

- Permeability measurements made on 36 intact samples from five wells in south Texas
- Permeability increases with increasing calcite volume
- The lowest maturity samples contain viscous bitumen migrating through pores
- Thermally mature samples are filled with solid hydrocarbon, identified by visual kerogen analysis and solvent extraction as both bitumen and porous pyrobitumen

Summary, continued

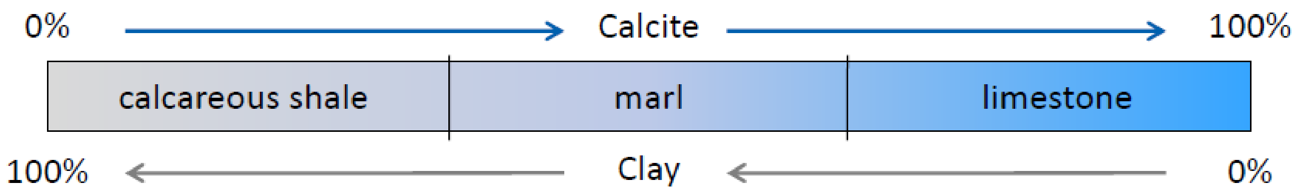
- The hydrocarbons within the Eagle Ford have migrated within the rock effectively occluding primary pores like a diagenetic cement
- Permeability decreases with increasing TOC
- Our results suggest that the Eagle Ford is a dual-porosity reservoir in which matrix storage feeds a network of progressively larger natural and induced, propped hydraulic fractures that carry hydrocarbons to the wellbore

Background: Regional Depositional System



Background: Lithology

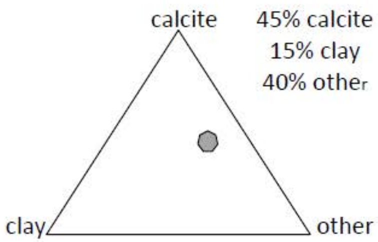
Two Component System

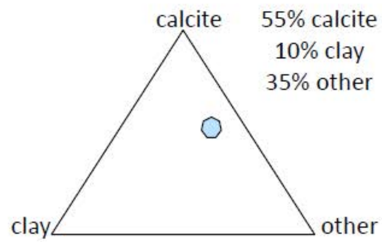


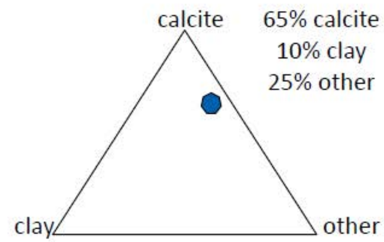
Attribute	Shale	Marl	Limestone
Abundance	<5%	60-70%	30-40%
Calcite	<25%	45-55%	75-85%
Clay	50-60%	10-15%	5%
TOC	<2%	2-10%	<2%
Porosity	---	8-12%	3-4%
Young's Modulus	--	2-4	4-6

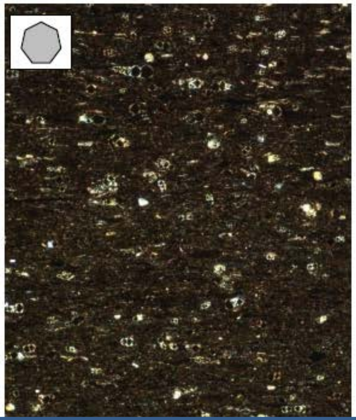
J. Breyer and others (2015)

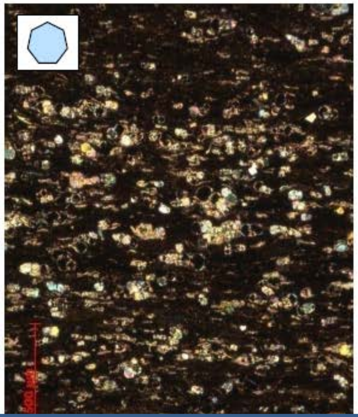
Marls and Limestones

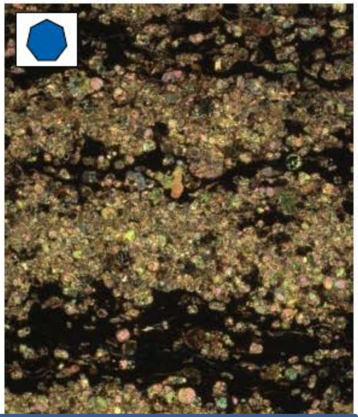


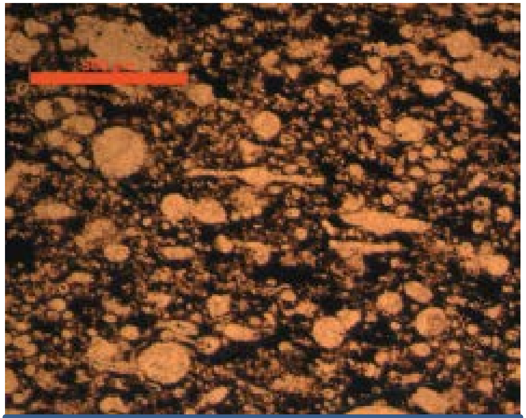












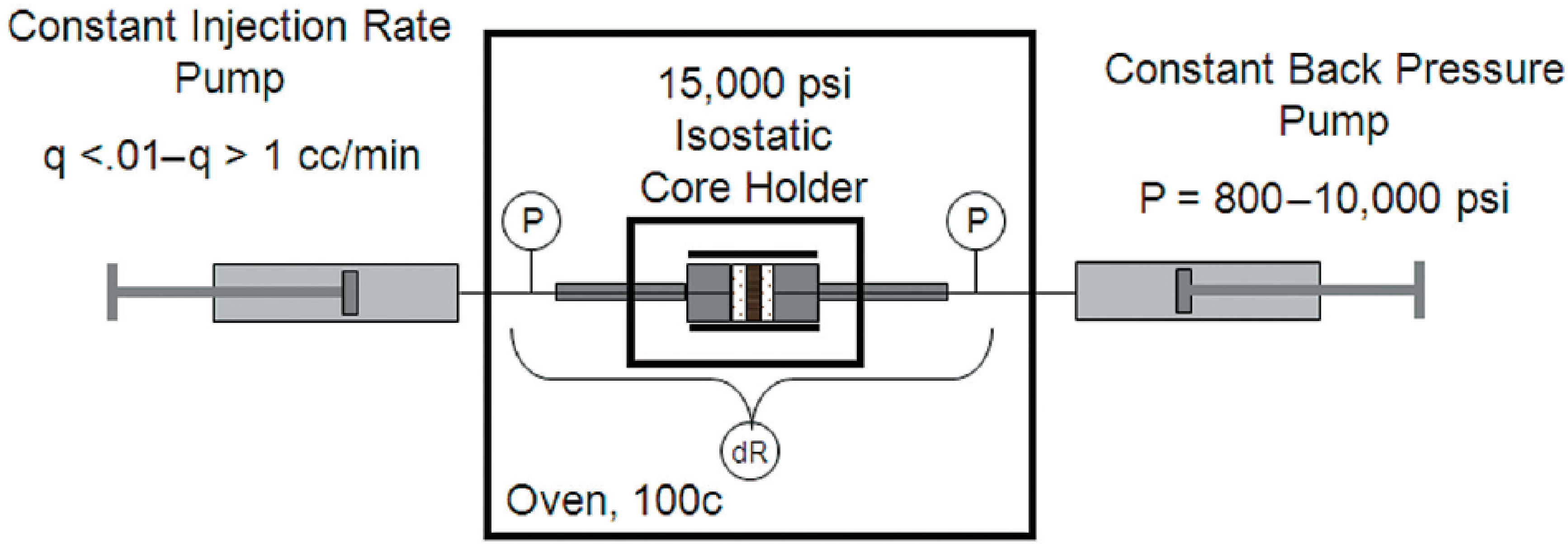
Marls: increasing lamination →

Limestone

Increasing Calcite
Decreasing TOC
Permeability?

J. Breyer and others (2015)

Permeability measurements



- Low viscosity, low compressibility supercritical fluids miscible with residual core liquids
- At steady state, both pumps move at an identical rate (within experimental error) creating a constant pressure differential across the core plug
- This experimental protocol is repeated at three different rates

Rosen et al. (2013)

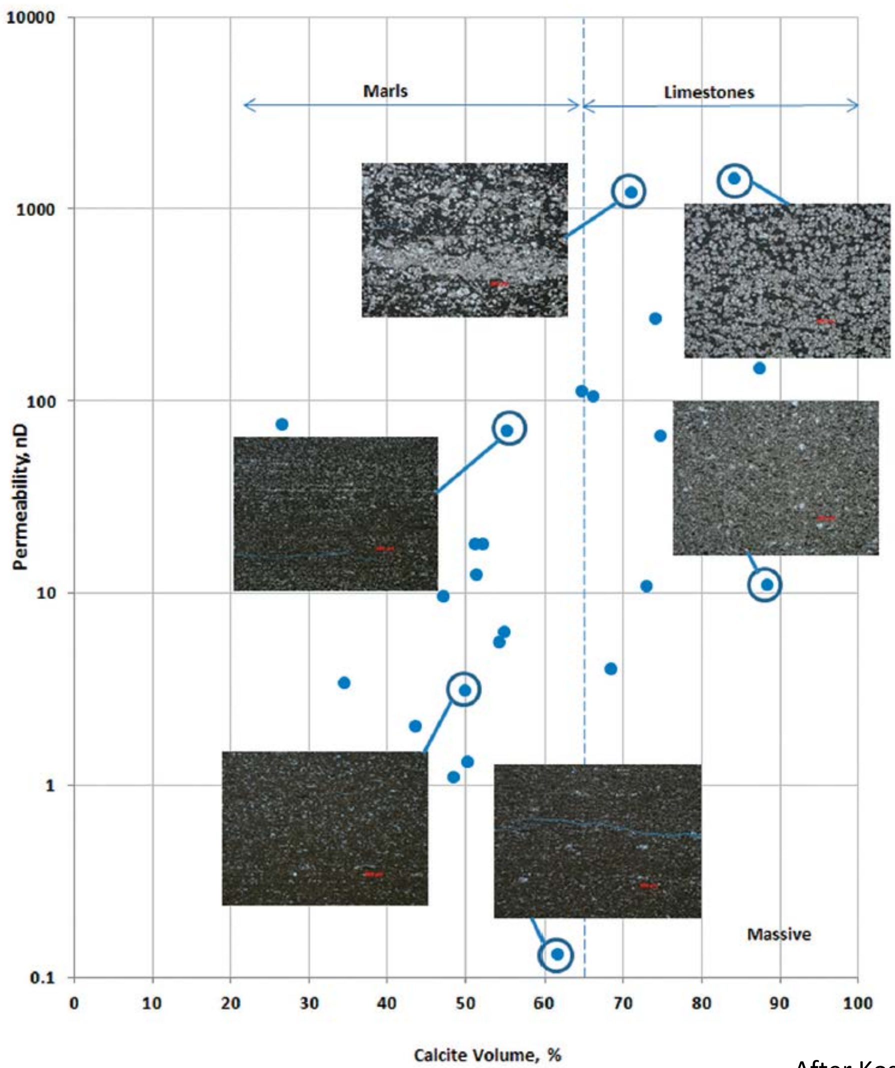
Permeability measurements

Well	Sample	Permeability (nD)	TOC (Wt. %)	Quartz (Vol. %)	Calcite (Vol. %)	Total Clays (Vol. %)
Well 1	1-1	61.00	N/A	N/A	N/A	N/A
Well 2	2-1	2.00	4.30	13.33	43.15	20.54
Well 2	2-2	4.00	5.41	13.61	33.42	33.17
Well 2	2-3	6.20	4.43	12.89	53.79	17.19
Well 2	2-4	11.00	2.51	9.87	70.81	6.37
Well 2	2-5	18.00	3.12	13.09	47.46	10.79
Well 2	2-6	18.00	4.45	12.91	50.38	15.32
Well 2	2-7	22.00	4.20	11.22	49.62	14.79
Well 2	2-8	70.00	1.62	8.93	73.72	6.77
Well 2	2-9	77.00	2.55	6.16	23.06	36.66
Well 2	2-10	112.00	2.48	14.93	65.32	8.21
Well 3	3-1	0.13	N/A	N/A	N/A	N/A
Well 3	3-2	1.10	N/A	N/A	N/A	N/A
Well 3	3-3	3.10	N/A	N/A	N/A	N/A
Well 3	3-4	28.28	N/A	N/A	N/A	N/A
Well 3	3-5	52.50	N/A	N/A	N/A	N/A
Well 3	3-6	64.99	N/A	N/A	N/A	N/A
Well 3	3-7	78.02	N/A	N/A	N/A	N/A
Well 3	3-8	105.67	N/A	N/A	N/A	N/A
Well 3	3-9	147.43	N/A	N/A	N/A	N/A
Well 4	4-1	0.46	5.11	12.68	61.10	7.93
Well 4	4-2	1.32	6.44	18.50	47.67	13.85
Well 4	4-3	2.00	5.54	14.03	50.31	14.80
Well 4	4-4	3.40	5.92	14.56	49.91	15.14
Well 4	4-5	5.50	2.44	12.03	68.05	6.06
Well 4	4-6	9.61	4.21	14.46	54.55	15.44
Well 4	4-7	10.80	3.47	14.80	47.01	22.66
Well 4	4-8	12.42	1.16	4.23	88.41	2.03
Well 4	4-9	75.00	4.44	11.47	55.28	15.26
Well 4	4-10	125.00	3.04	11.96	64.19	9.80
Well 4	4-11	265.00	2.25	4.03	87.48	2.28
Well 4	4-12	329.00	5.87	10.24	74.14	2.19
Well 4	4-13	1426.00	6.76	6.61	70.53	3.69
Well 4	4-14	5944.00	2.68	5.17	84.14	2.36
Well 5	5-1	0.09	N/A	N/A	N/A	N/A
Well 5	5-2	1218.81	N/A	N/A	N/A	N/A

- **36 measurements**
- **5 wells**
- **Varying maturity**
- **Porosity**
  - **Limestones 4 – 6%**
  - **Marls 8 – 12%**

Kosanke and Warren (2016)

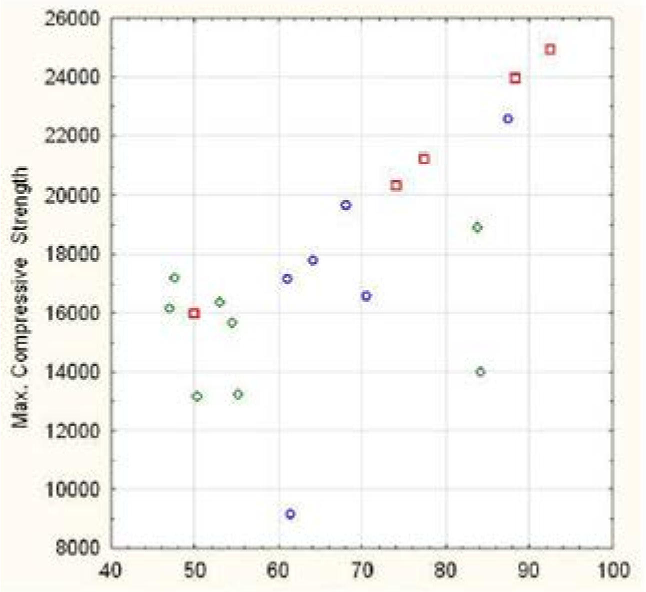
Permeability vs. Calcite Volume



After Kosanke and Warren (2016), Rosen et al. (2013)

Permeability vs. Calcite Volume

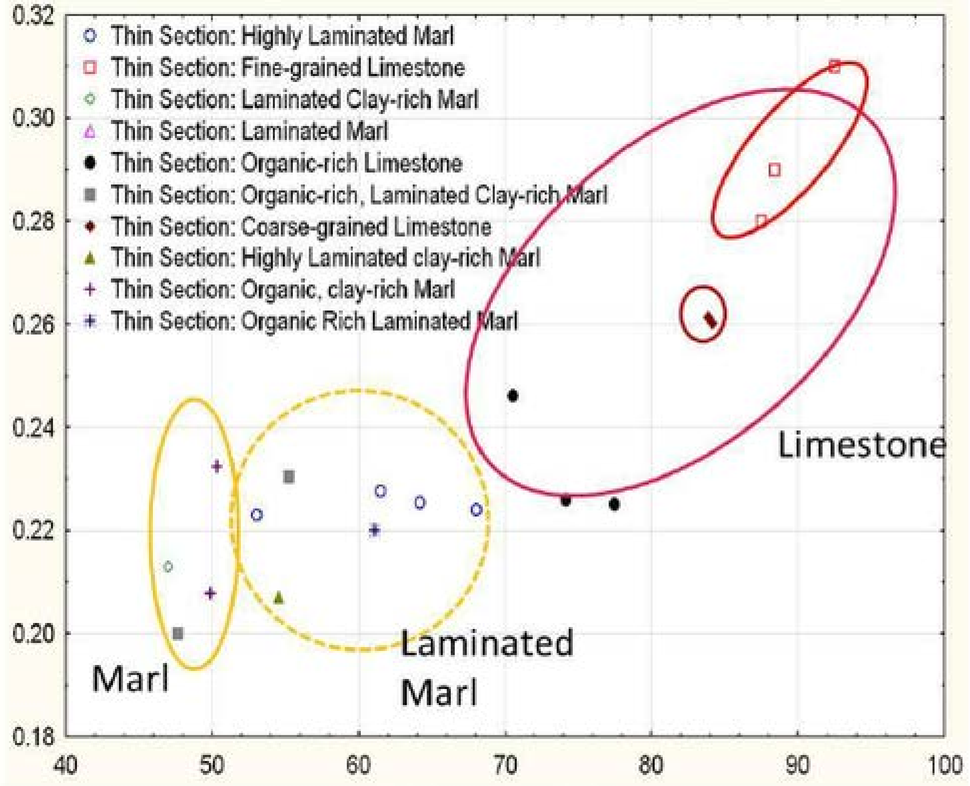
Maximum Compressive Strength



Calcite volume %

Measurements from Marathon Tech Lab

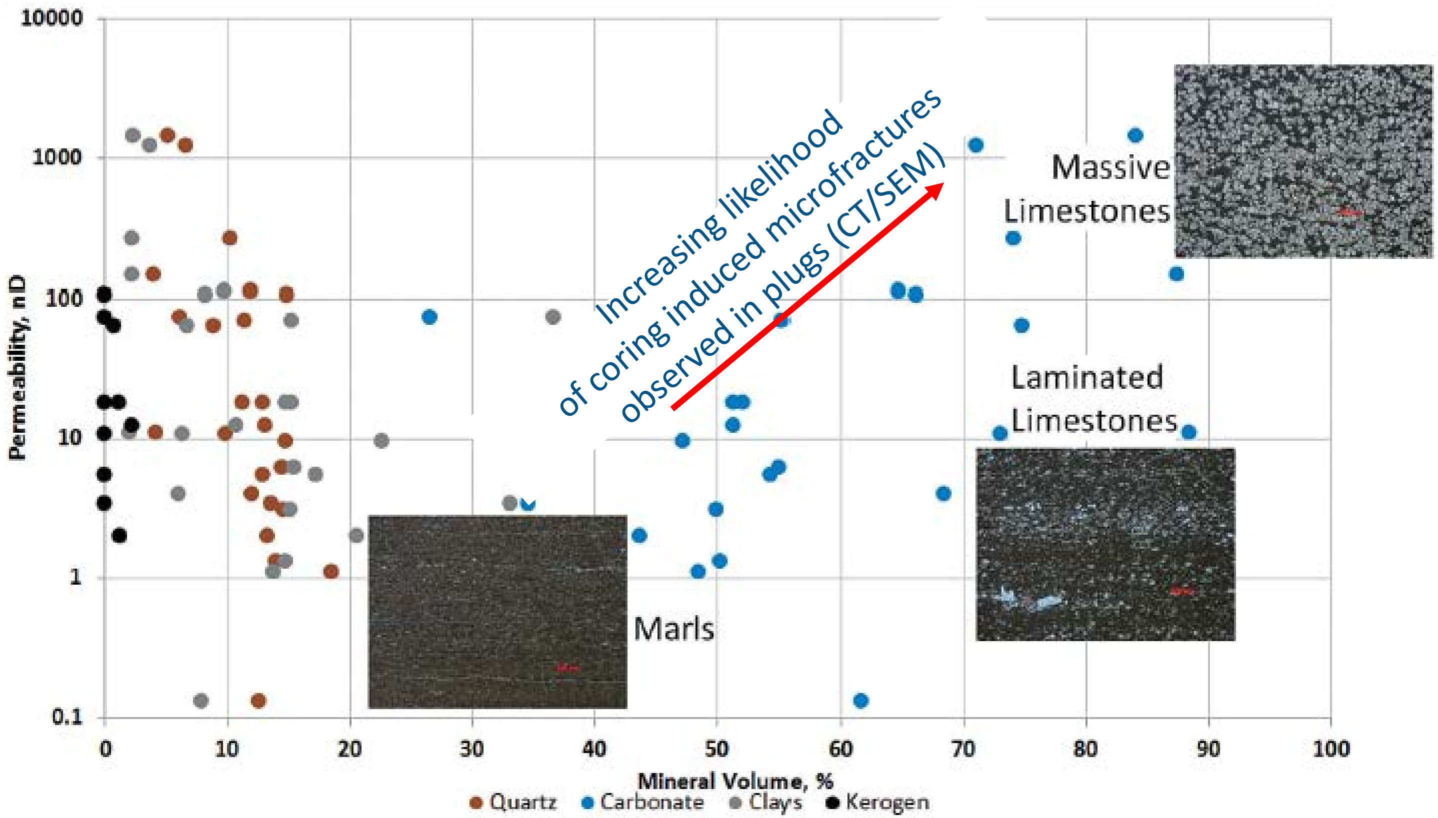
Poisson's Ratio (Vertical)



Calcite volume %

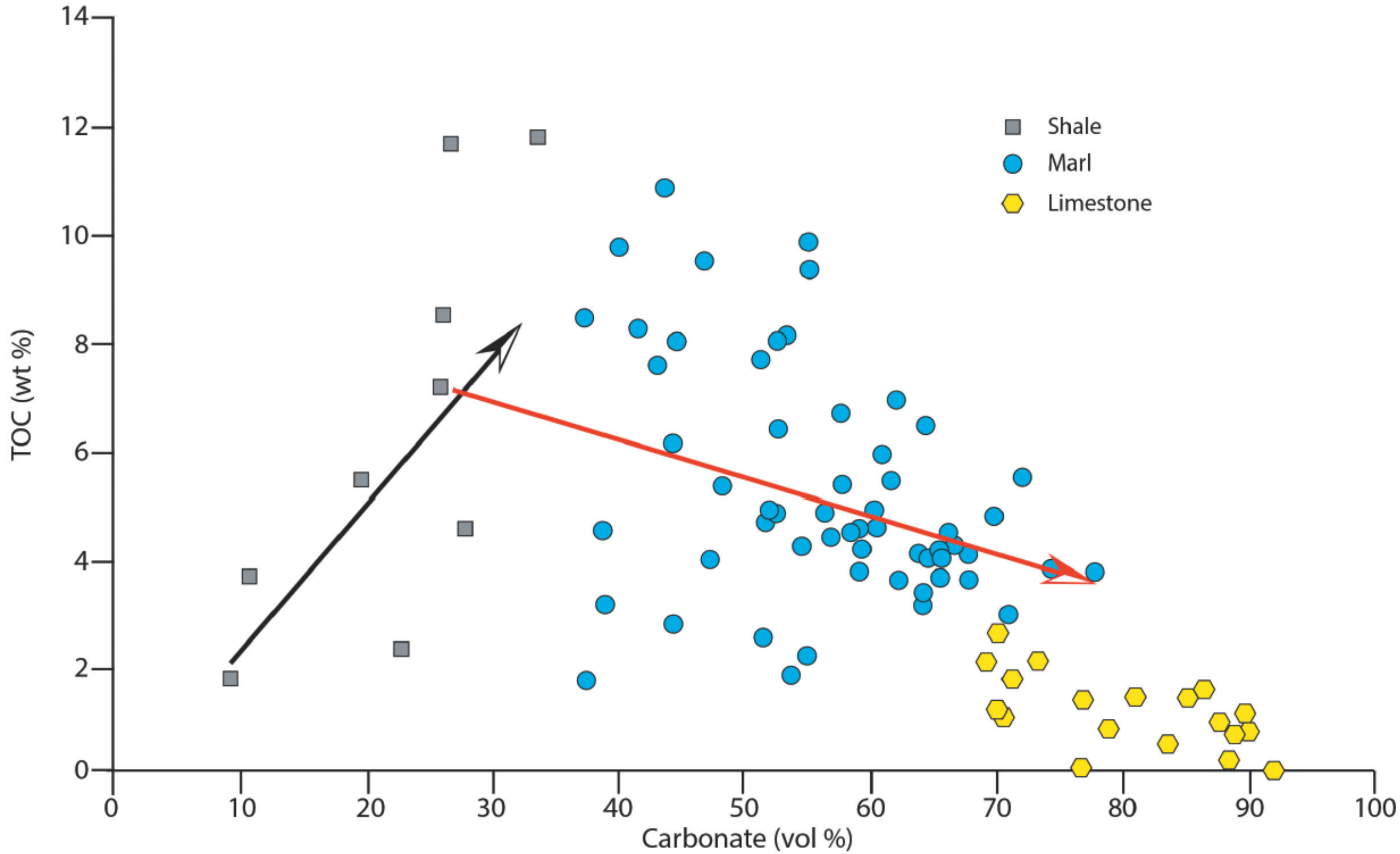
J. Breyer and others (2015)

Permeability vs. Mineralogy



Rosen et al. (2013)

Lithology and TOC



Argillaceous Mudrock Trend

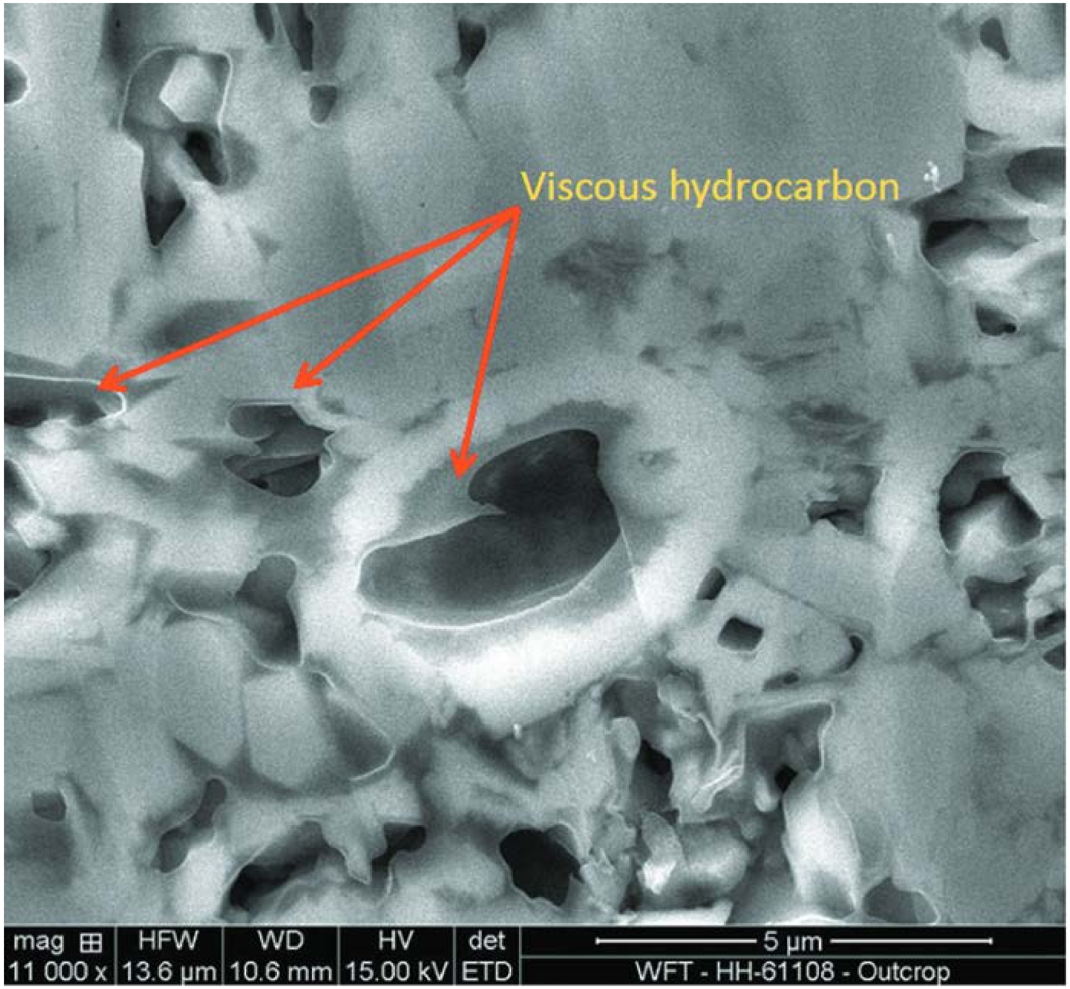
Calcareous Mudrock Trend

J. Breyer and others (2015)

Marl Matrix Organic Matter

- Ar-ion-milled end cuts from plugs and outcrop
- Environmental stage (liquid/viscous hydrocarbons)
- Secondary electron (SE) imaging

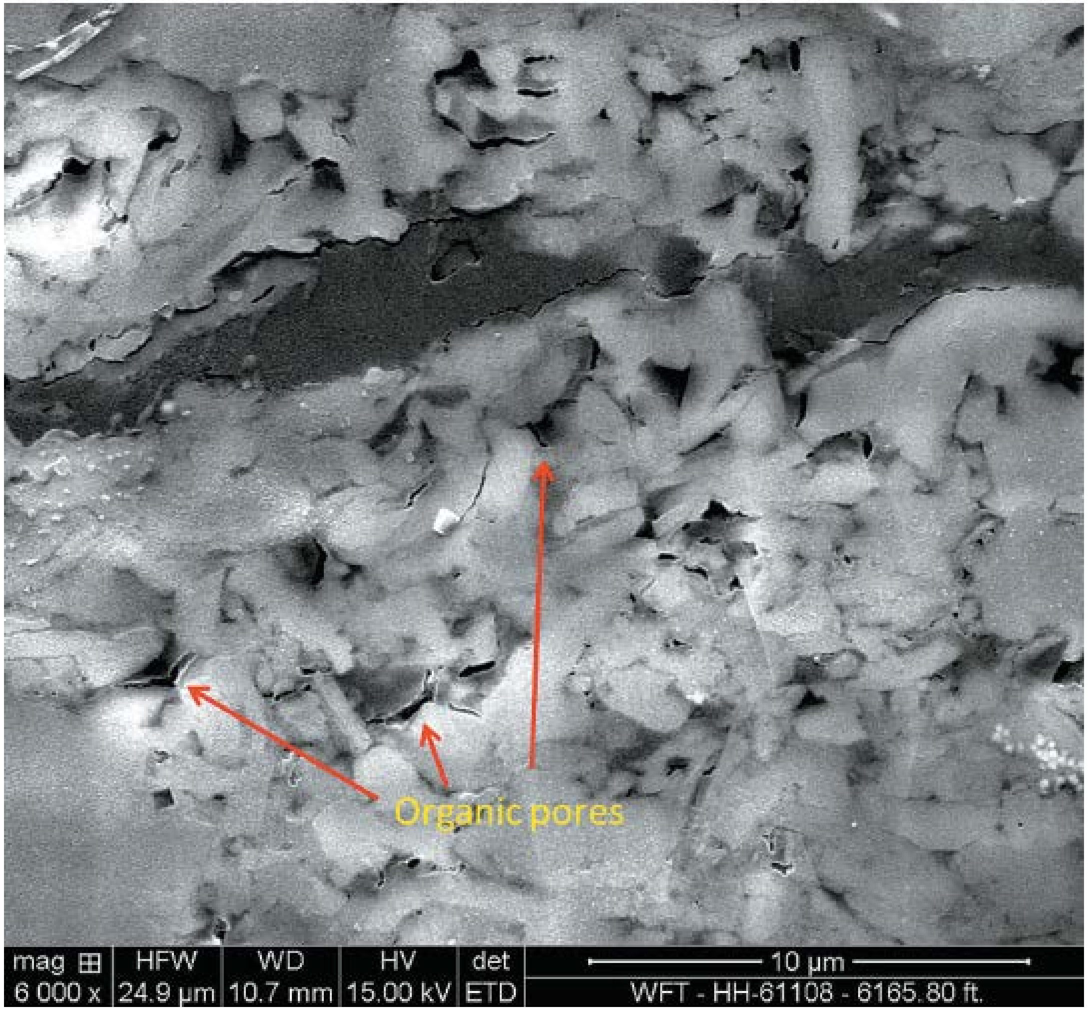
Marl Matrix Organic Matter: Outcrop, Ro = 0.4



“Pre-oil” bitumen migrating through pores

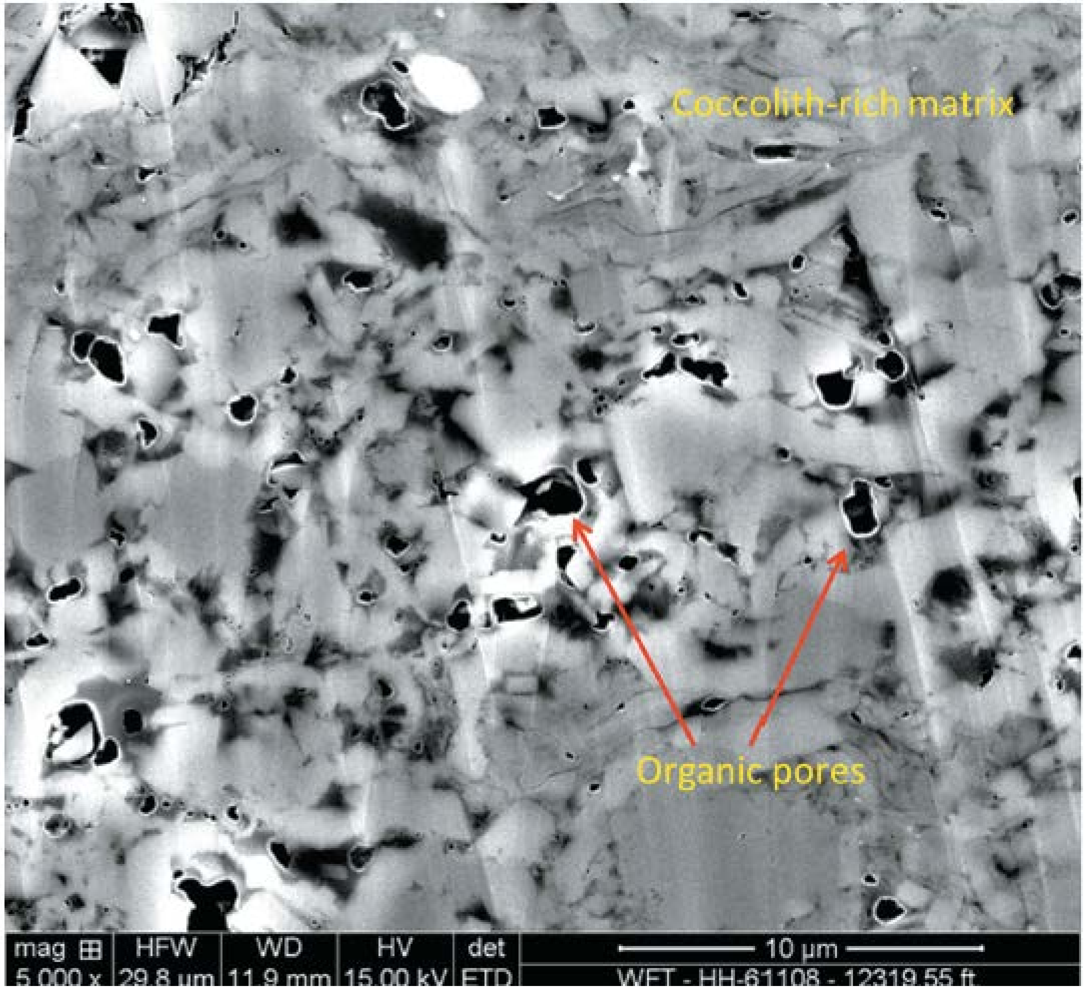
Kosanke and Warren (2016)

Marl Matrix Organic Matter: Ro = 0.62



Bitumen "cement" with slit-shaped shrinkage pores Kosanke and Warren (2016)

Marl Matrix Organic Matter: Ro = 1.45



Intergranular pores filled with porous pyrobitumen "cement"

Kosanke and Warren (2016)

Controls on Permeability (small data set…)

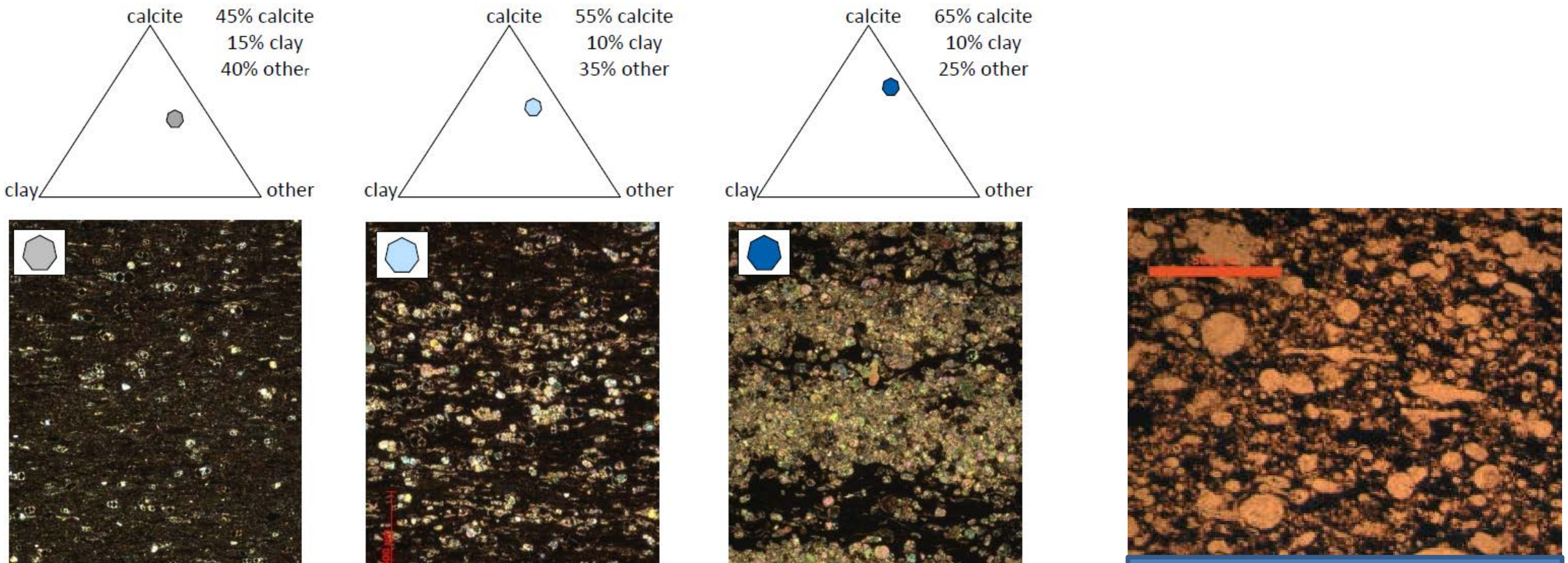
Rock Type	Permeability (nD)	Permeability (nD)	Permeability (nD)
	Means	N	Std. Dev.
Marl	17.3	8	25.3
Laminated Marl	33.8	7	47.8
Limestone	908.1	9	1940.9

Marls (Permeability < 115 nD)

TOC	Permeability (nD)	Permeability (nD)	Permeability (nD)
	Means	N	Std. Dev.
TOC High	13.1	11	21.7
TOC Medium	39.1	6	44.5
TOC Low	41.2	2	40.7

Low TOC < = 2 wt. %
Medium TOC >2 < 4 wt. %
High >= 4 wt. %

Marls and Limestones



Marls: increasing lamination →

Limestone

Increasing Calcite

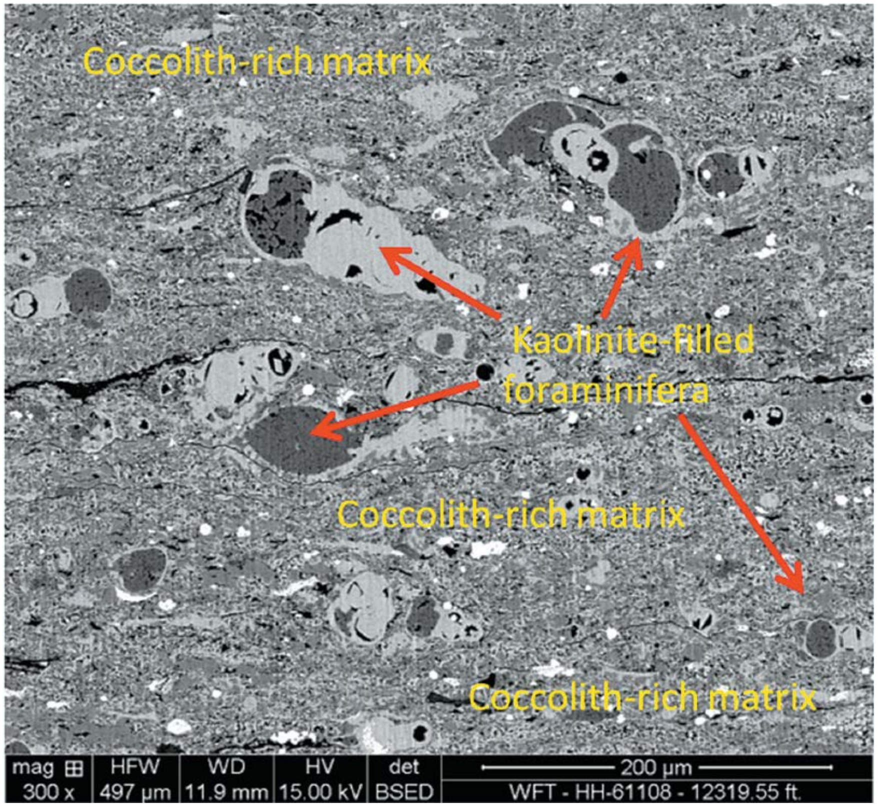
Decreasing TOC

Increasing Brittleness = Permeability

J. Breyer and others (2015)

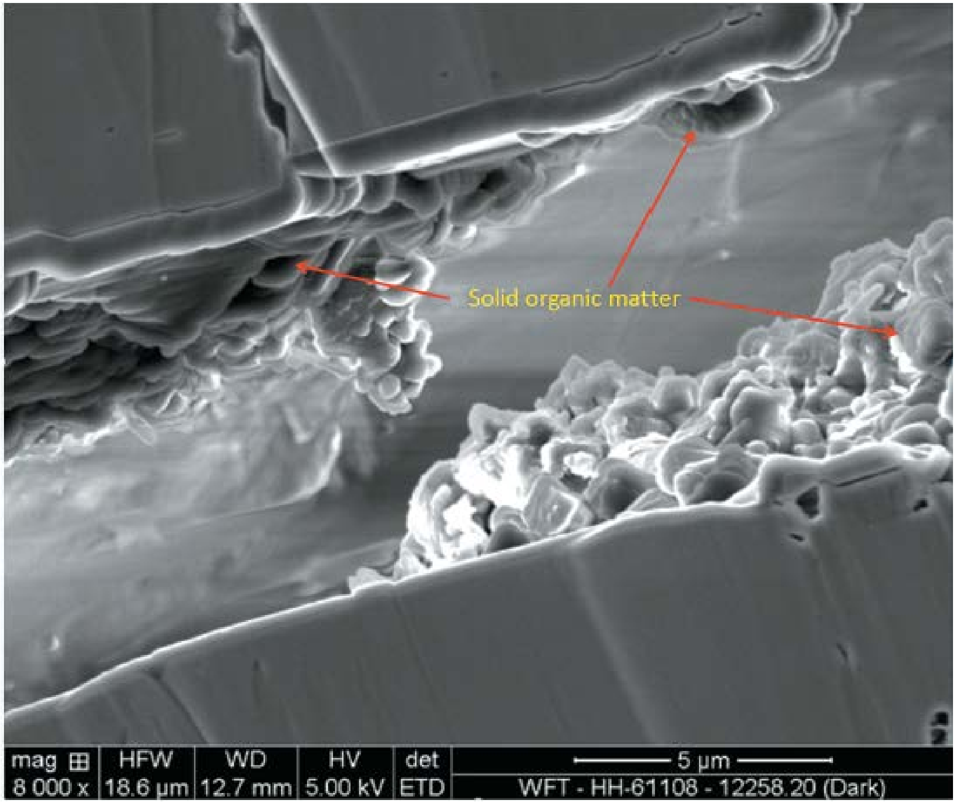
Microfractures Observed in Marls and Limestones

Marl (Sample 4-9, K = 75 nD)



Microfractures produced by coring process (no mineralization/pyrobitumen in fractures) **Very prevalent.**

Limestone (Sample 4-14, K = 5944 nD)

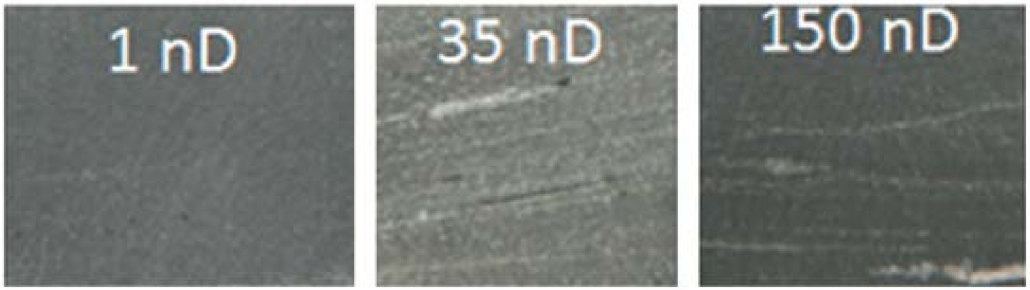


Microfractures present in subsurface (mineralization/pyrobitumen in fractures) **Rarely observed.**

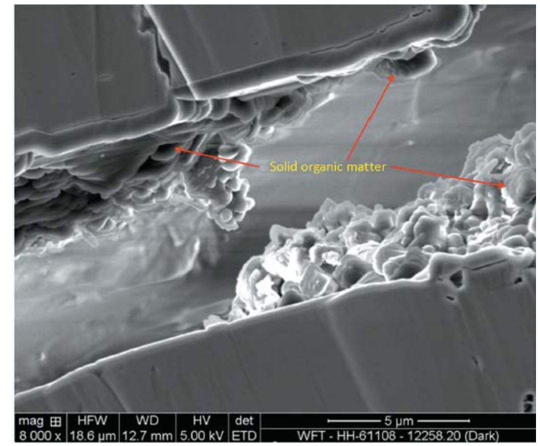
Kosanke and Warren (2016)

Permeability: Matrix and Fractures

Marl Matrix (Storage) Permeability



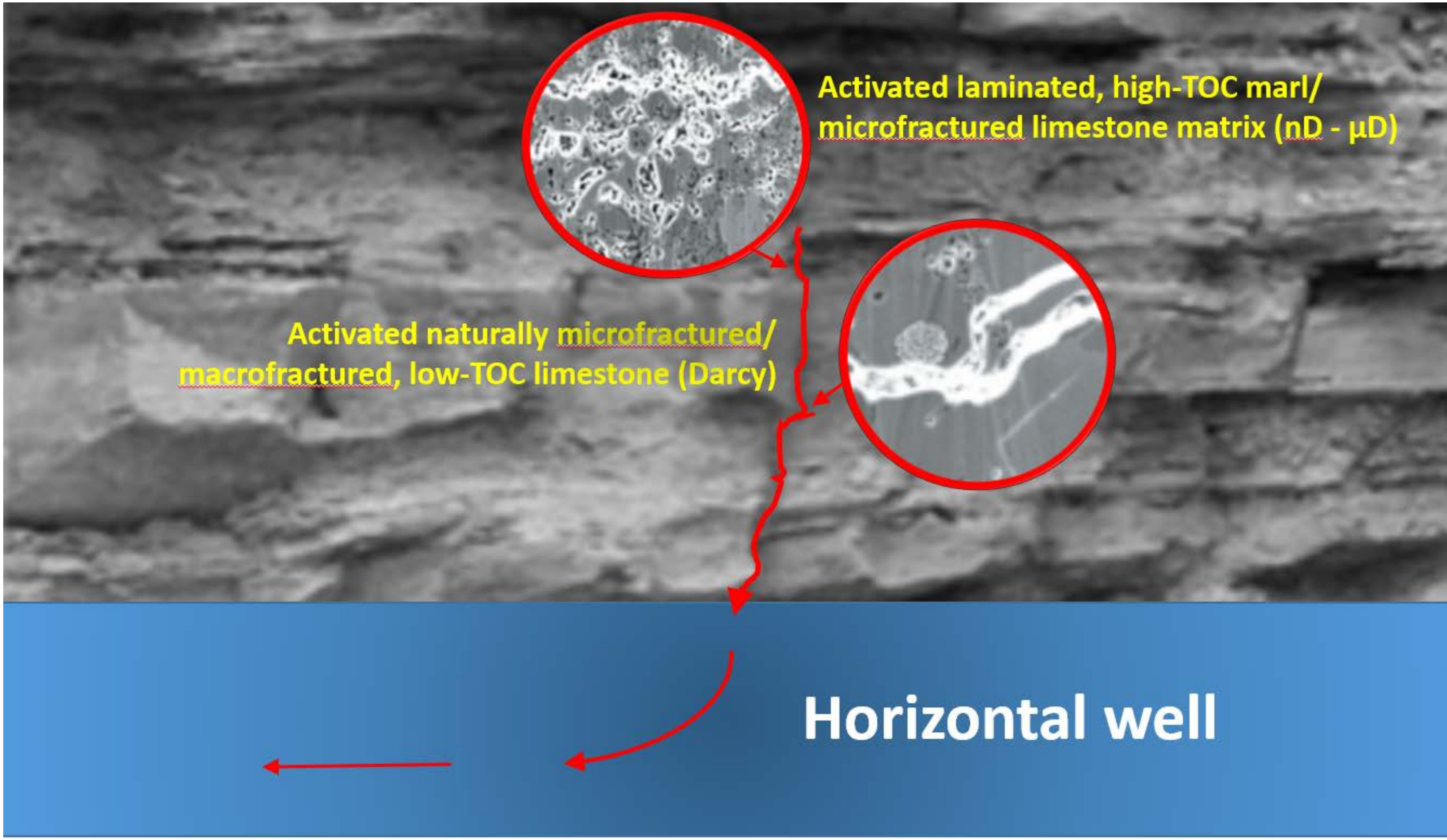
Observed Plug /
Thin Section-Scale Fractures



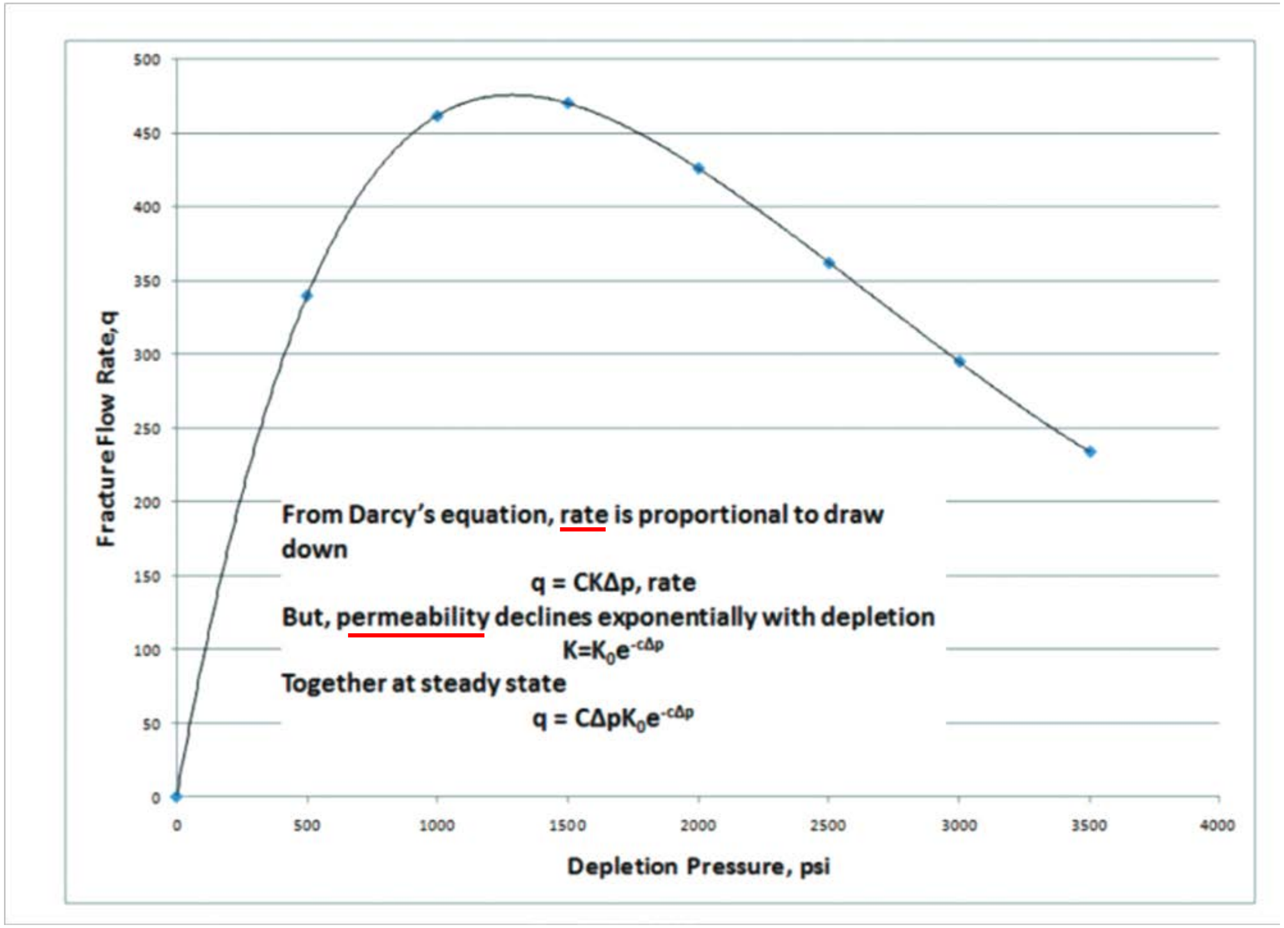
Observed Core-Scale Fractures

Observed Outcrop-Scale Fractured

Eagle Ford: Dual-Porosity Reservoir



Stress Dependence: Choke Management



Fast drawdown rate produces more than a slow drawdown rate but eventually this trend reverses

Rosen et al. (2013)

Choke Management

- Fast drawdown rate initially produces more than a slow drawdown rate but this trend reverses
- If the reservoir is produced at a rate faster than the matrix can resupply the fractures with fluids a large loss in permeability will result
- This is likely a significant factor contributing to the high decline rates seen in unconventional shale plays

Conclusions

- Permeability measurements made on 36 intact samples from five wells in south Texas

- Permeability increases with increasing calcite volume – likely due to increasing ‘brittleness’ and likelihood of fracturing

Conclusions, continued

- The hydrocarbons within the Eagle Ford have migrated within the rock effectively occluding primary pores like a diagenetic cement
- Permeability decreases with increasing TOC
- The Eagle Ford is a dual-porosity reservoir in which matrix storage feeds a network of progressively larger natural and induced, propped hydraulic fractures that carry hydrocarbons to the wellbore