# Optimizing Completion in Unconventionals: What We Know Now*

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## Abstract

During the past decade, there has been a continuing surge in the production of unconventional resources, accompanied with which is the great challenge and opportunities in unconventional resources research. Hydraulic fracturing technique is used to create fractures, enhance permeability and therefore economical production of the unconventional resources. The resulting fractures and their spacing (density) inside the stimulated reservoir volume (SRV) is a key factor in economical production from these very low permeability resources. It is believed that gas production enhanced by increasing fracture density resulted from hydraulic fracturing. However, there is no study about effect of fracture density on production from gas condensate unconventional resources. Eagle Ford shale is considered as one of the most important oil and gas shale plays in North America. In this study, we focused on finding the optimum fracture spacing (density) to maximize the production from the Eagle Ford gas condensate window.

In this study, we modeled a SRV in the Eagle Ford gas condensate window. Based on MICP experiment results and pore-throat size distribution of an Eagle Ford shale sample, the pore volume of the reservoir around the hydraulic fracture was divided into five regions.  The physics of multiphase flow of gas and condensate were modified in order to take into account the effect of pore size on phase behavior, permeability and non-Darcy flow and therefore production from Eagle Ford gas condensate window. For each pore size, a specific permeability and PVT properties were assigned. Organic and inorganic pores with different wettability preferences were randomly distributed in the model with activated desorption mechanism in organic pores. We considered fracture spacing of 160ft, 80ft, 40ft, and 20ft inside the SRV and analyzed the effect of fracture density on production.

Results indicated that the non-Darcy flow and desorption mechanisms are absent in the early stages of production where the pressure is significantly high. However, as the reservoir depletes, slip and transition flow occurs, which results in an increase in apparent permeability and the adsorbed phase starts to desorb from the rock surface. Moreover, decreasing fracture spacing from 160 ft to 20 ft increases cumulative gas production. On the other hand, there exists an optimum fracture spacing for condensate production. Low fracture spacing (20 ft) caused more condensate dropout because of significant pressure drop. Thus, while the general belief is that higher fracture density results in higher gas production, the results of this study revealed that cumulative condensate production decreases for higher fracture densities in long-term production due mainly to the condensate drop out effect.

## Selected References

Ambrose, R.J., R.C. Hartman, and I.Y. Akkutlu, 2011, Multi-component Sorbed Phase Considerations for Shale Gas-in-Place Calculations: Paper SPE 141416 presented at the SPE Production and Operations Symposium held in Oklahoma City, Oklahoma, 27-29 March.

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Loucks, R.G., R.M. Reed, S.C. Ruppel, and D.M. Jarvie, 2009, Morphology, Genesis, and Distribution of Nanometer-Scale Pores in Siliceous Mudstones of the Mississippian Barnett Shale: Journal of Sedimentary Research, v. 79/12, p. 848-861.

Warpinski, N.R., M.J. Mayerhofer, M.C. Vincent, C.L. Clipolla, and E.P. Lolon, 2008, Stimulating unconventional reservoirs: Maximizing network growth while optimizing fracture conductivity: 2008 SPE Unconventional Reservoirs Conference, Keystone, CO, SPE 114173.

Ziarani, A.S., and R. Aguilera, 2012, Knudsen’s permeability correction for tight porous media: Transp Porous Media, v. 91/1, p. 239–260.

# Optimizing Completion in Unconventionals: What We Know Now

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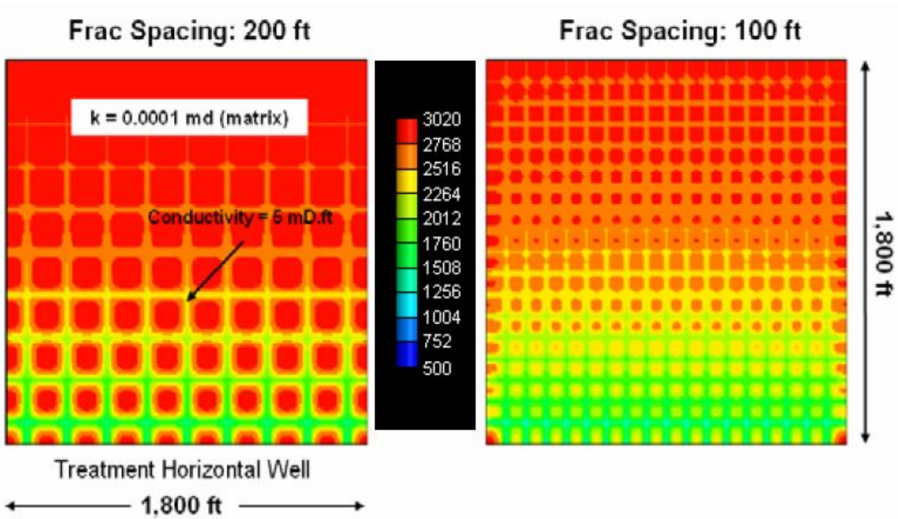
**Unconventionals Update**
**November 3, 2015**

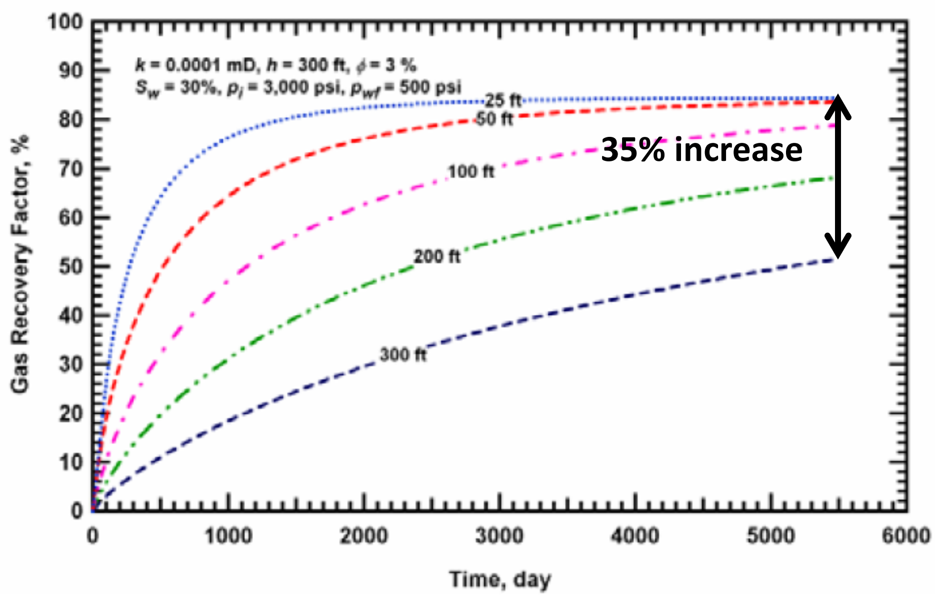
# Outlines

- Introduction
- Objective
- Petrophysical properties of the Eagle Ford Shale
- Synthetic reservoir model
- Confinement effect
- Non-Darcy flow and desorption effects
- Fracture density optimization
- Conclusions

# Introduction

- Hydraulic fracturing technique is used to create fractures and high permeability region.
- Warpinski et al. (2008) investigated the effect of fracture density on production from shale gas reservoirs.




Warpinski et al., 2008

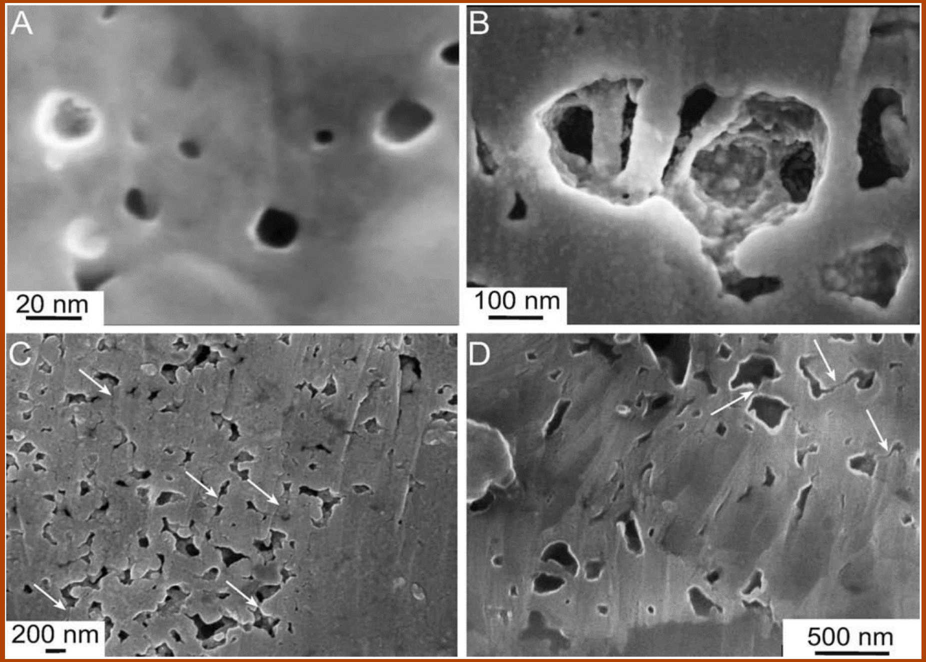
# Do we have the same physics of fluid phase behavior and transport in unconventionals?

- **Deviation of fluid properties under confinement**

- **The mean free path of molecules is in the order of the pore radius**

- **Organic nano-pores store a significant portion of gas in form of sorbed**

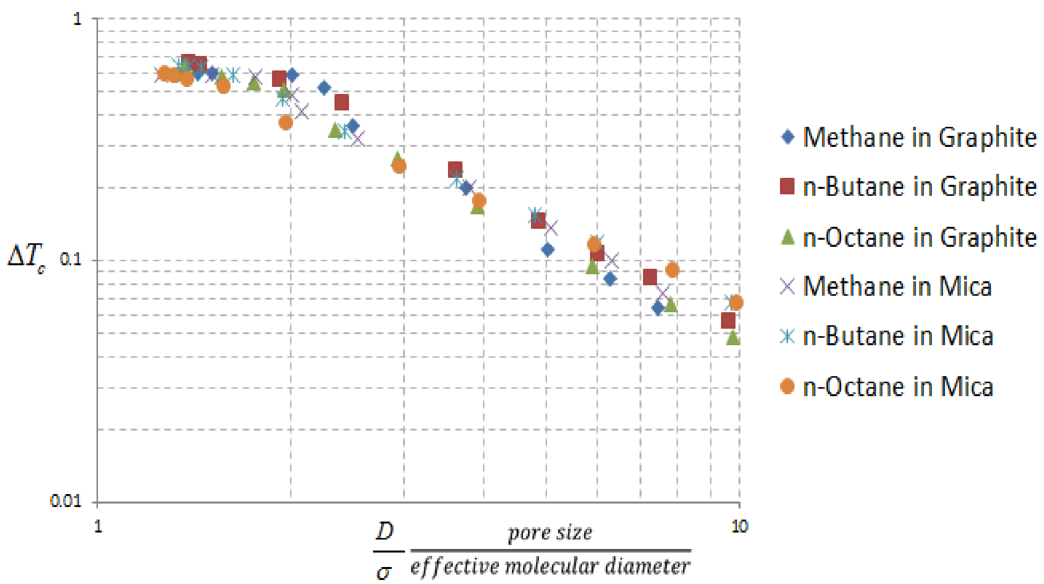
- **Pore connectivity**




**Loucks et al. (2009)**

# Introduction

- Pore-wall proximity effect on phase behavior




**Data points from Singh (2009) and correlation from Ma et al. (2013)**

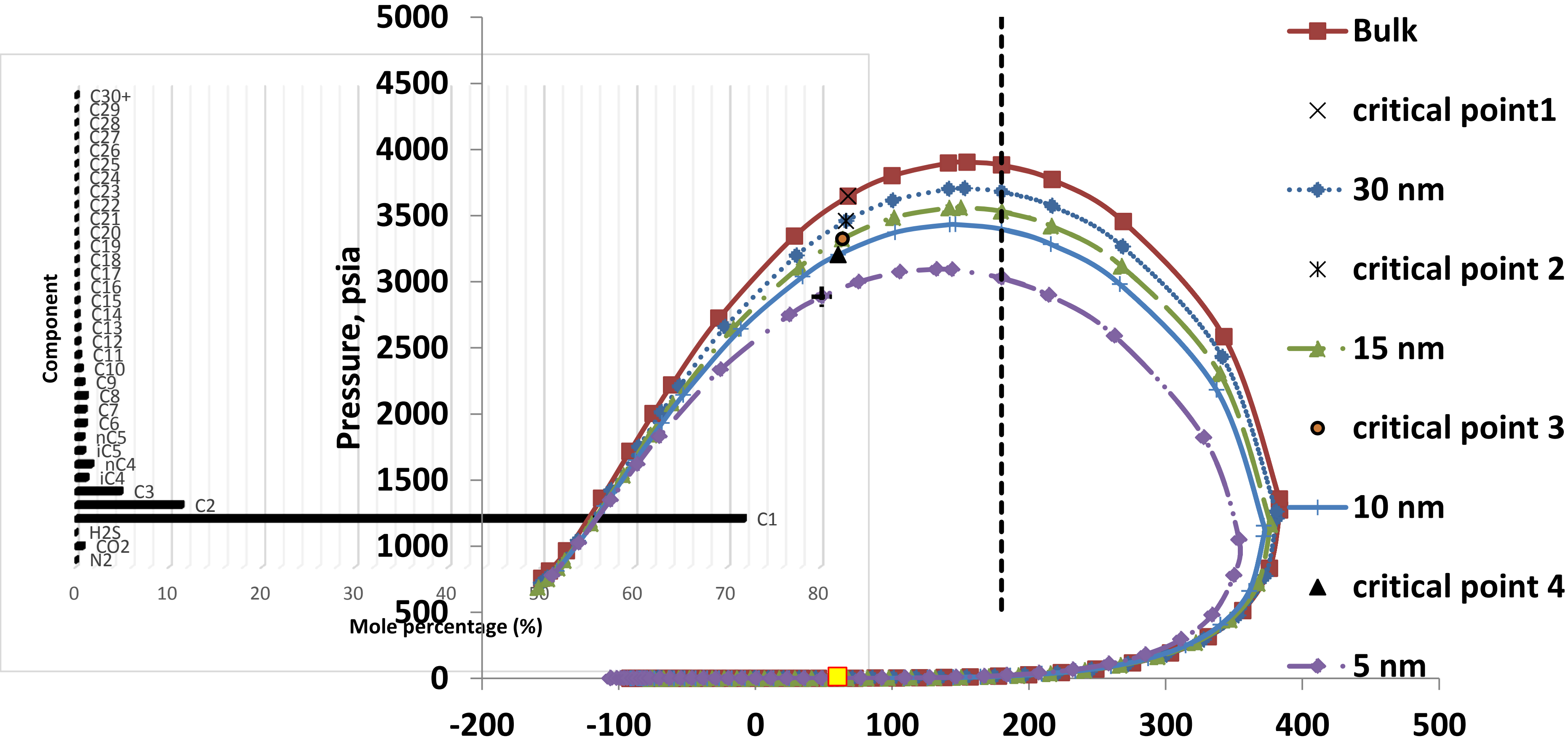
$$\Delta T_c = \frac{T_c - T_{cz}}{T_c} = 1.1775\left(\frac{D}{\sigma}\right)^{-1.338} \quad for \quad \left(\frac{D}{\sigma}\right) \geq 1.5$$

$$\Delta T_c = \frac{T_c - T_{cz}}{T_c} = 0.6 \quad for \quad \left(\frac{D}{\sigma}\right) \leq 1.5$$

$$\Delta P_c = \frac{P_c - P_{cz}}{P_c} = 1.5686\left(\frac{D}{\sigma}\right)^{-0.783}$$

# Introduction

- Two-phase envelope change due to confinement effects:

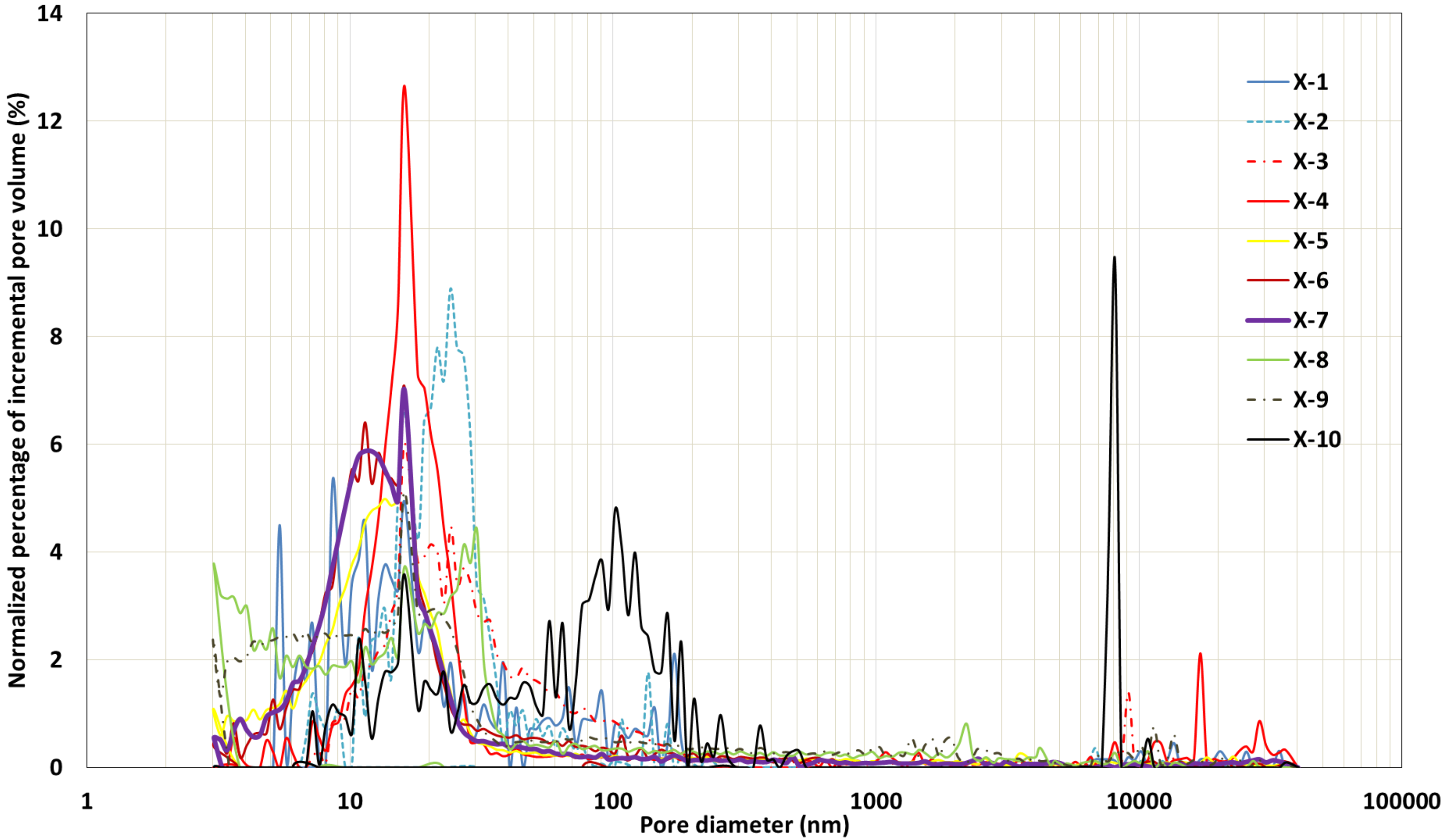



Reservoir fluid composition (Eagle Ford)

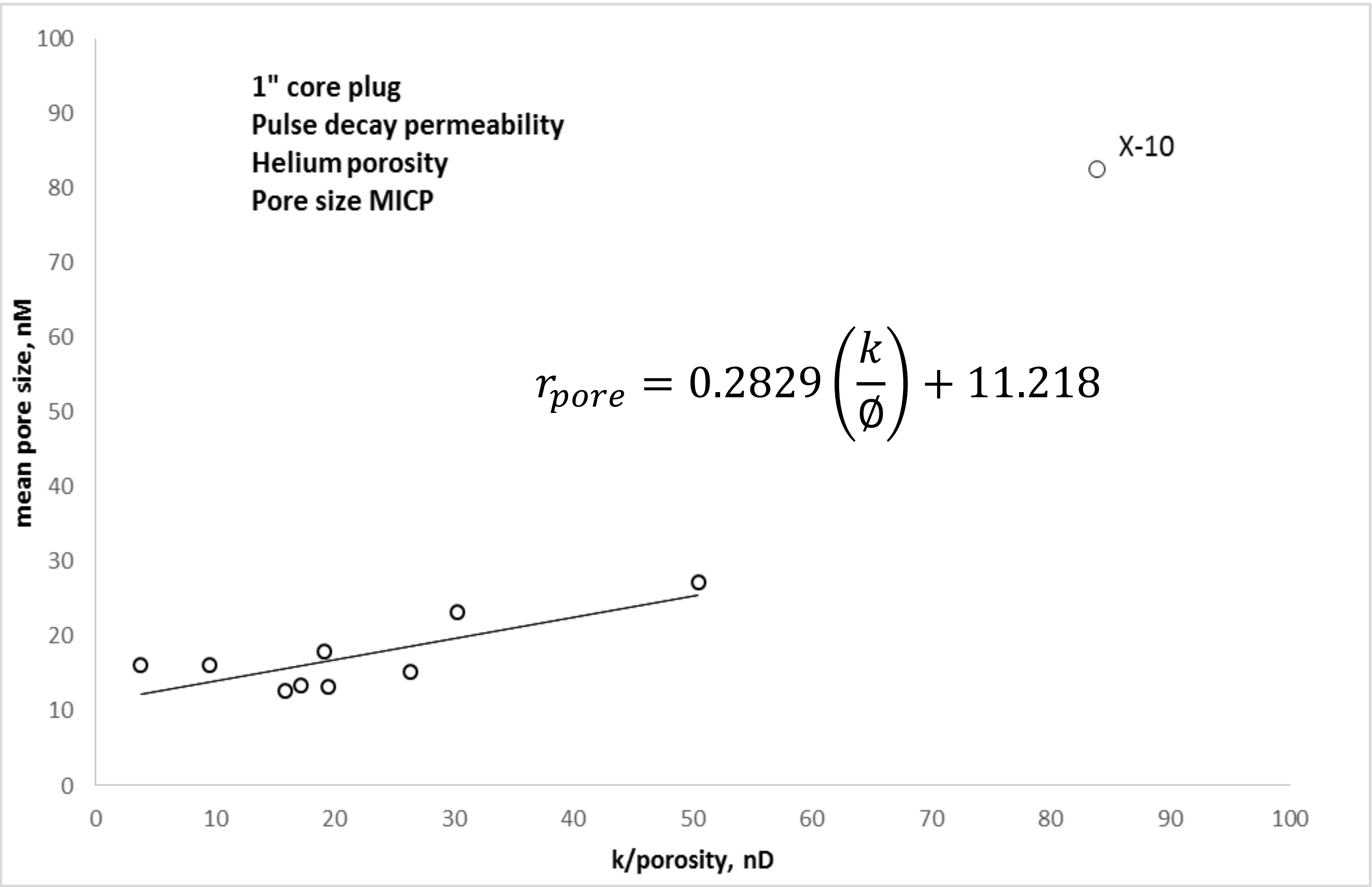
# Objective

- Optimum fracture density in the Eagle Ford gas condensate window
  - Phase behavior change in nanopores
  - Permeability as a function of pore size
  - Effect of Non-Dacry flow and desorption

# Pore throat size distribution



# Mean pore size vs. permeability/porosity




**From permeability, porosity, and MICP experiments on the Eagle Ford shale samples**

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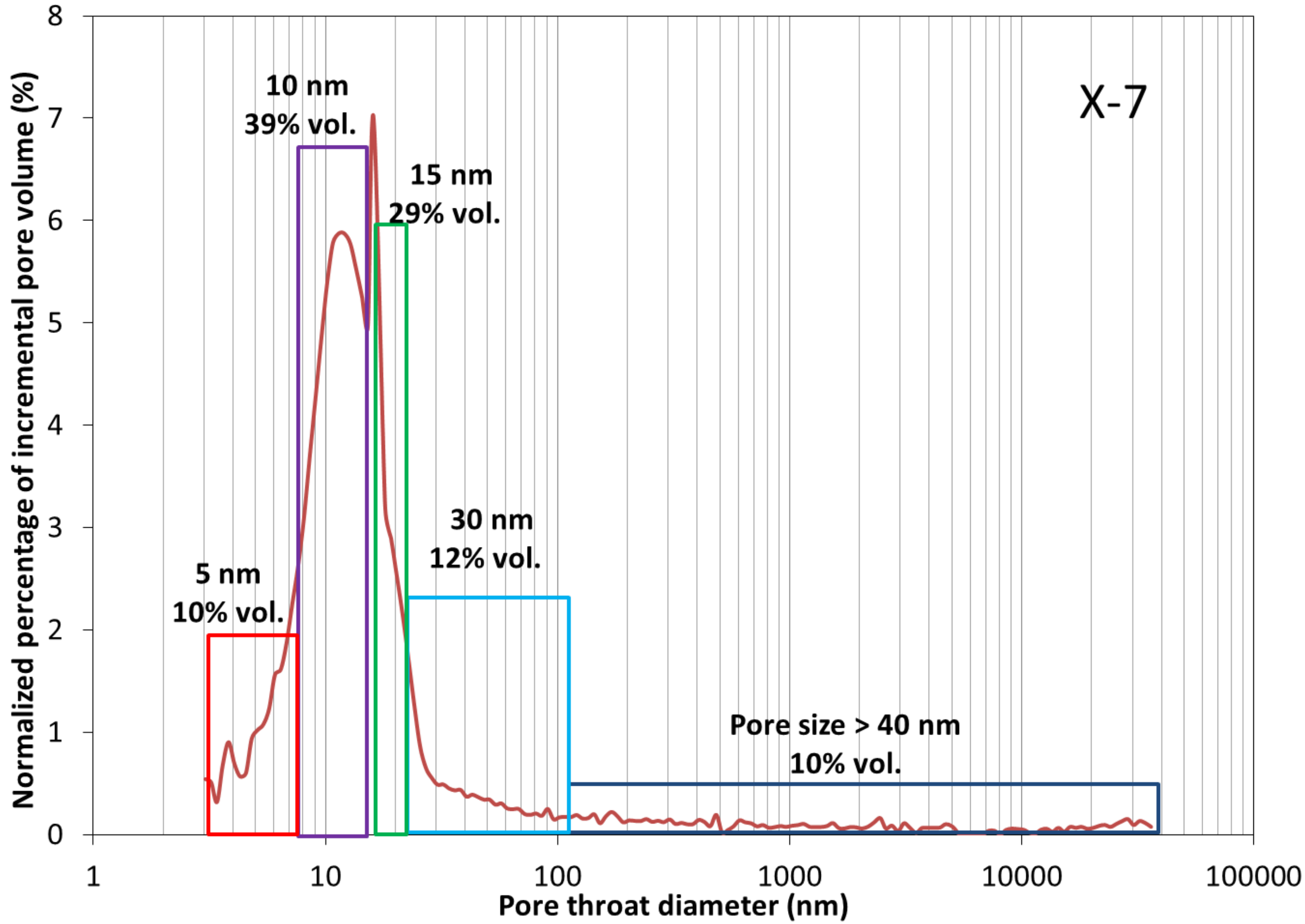
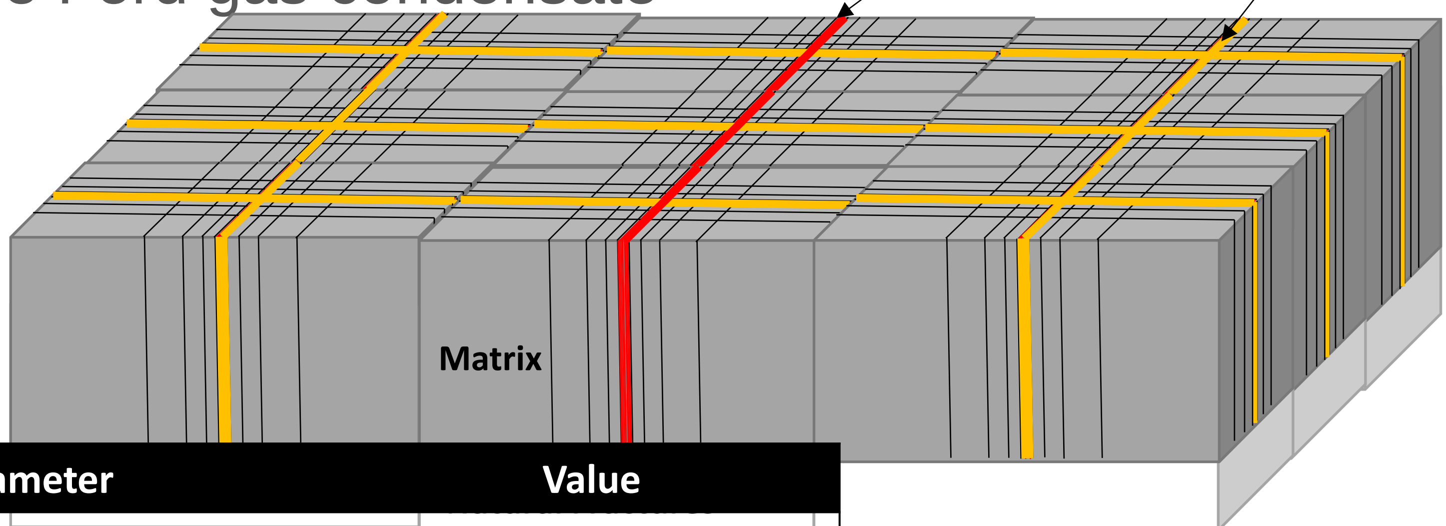
# Pore size distribution



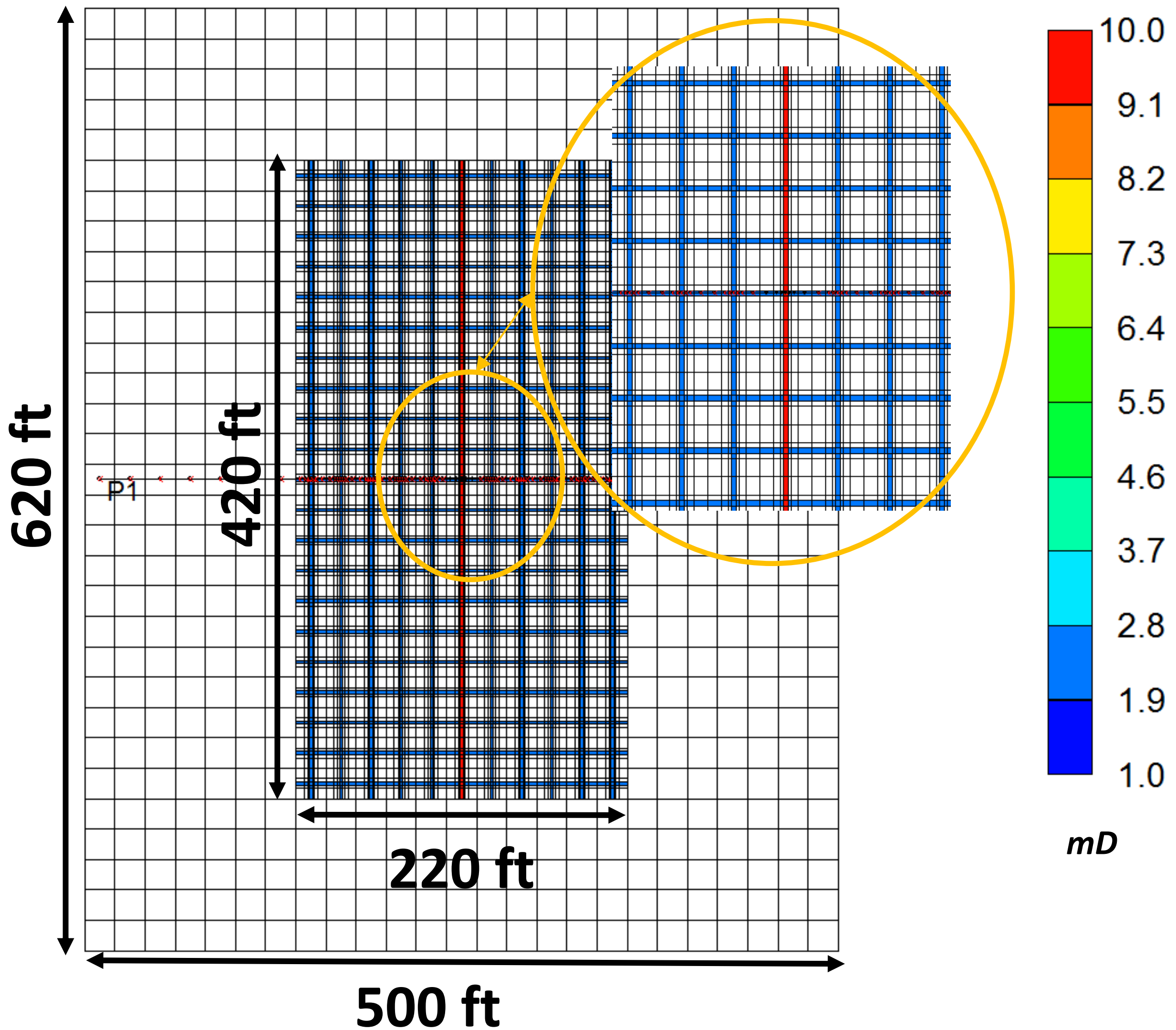
# Reservoir model

- Dual-permeability model
- Eagle Ford gas condensate

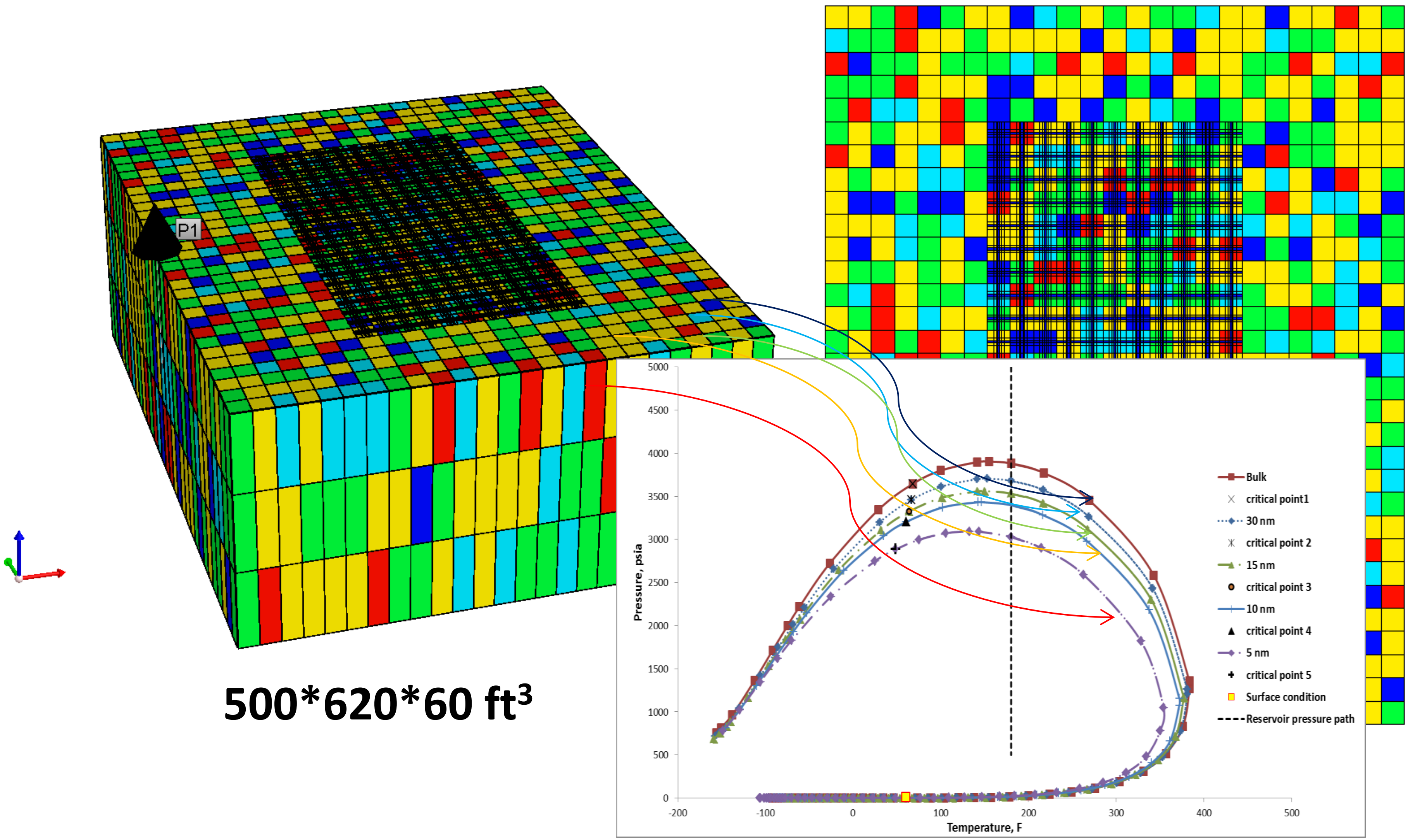



| Parameter | Value |
|---|---|
| Matrix permeability | 149 nD |
| Natural fracture conductivity | 0.02 mD-ft. |
| Propped fracture conductivity | 20 mD-ft. |
| Unpropped fracture conductivity | 4 mD-ft. |
| Matrix porosity | 9.4 % |

# Reservoir model

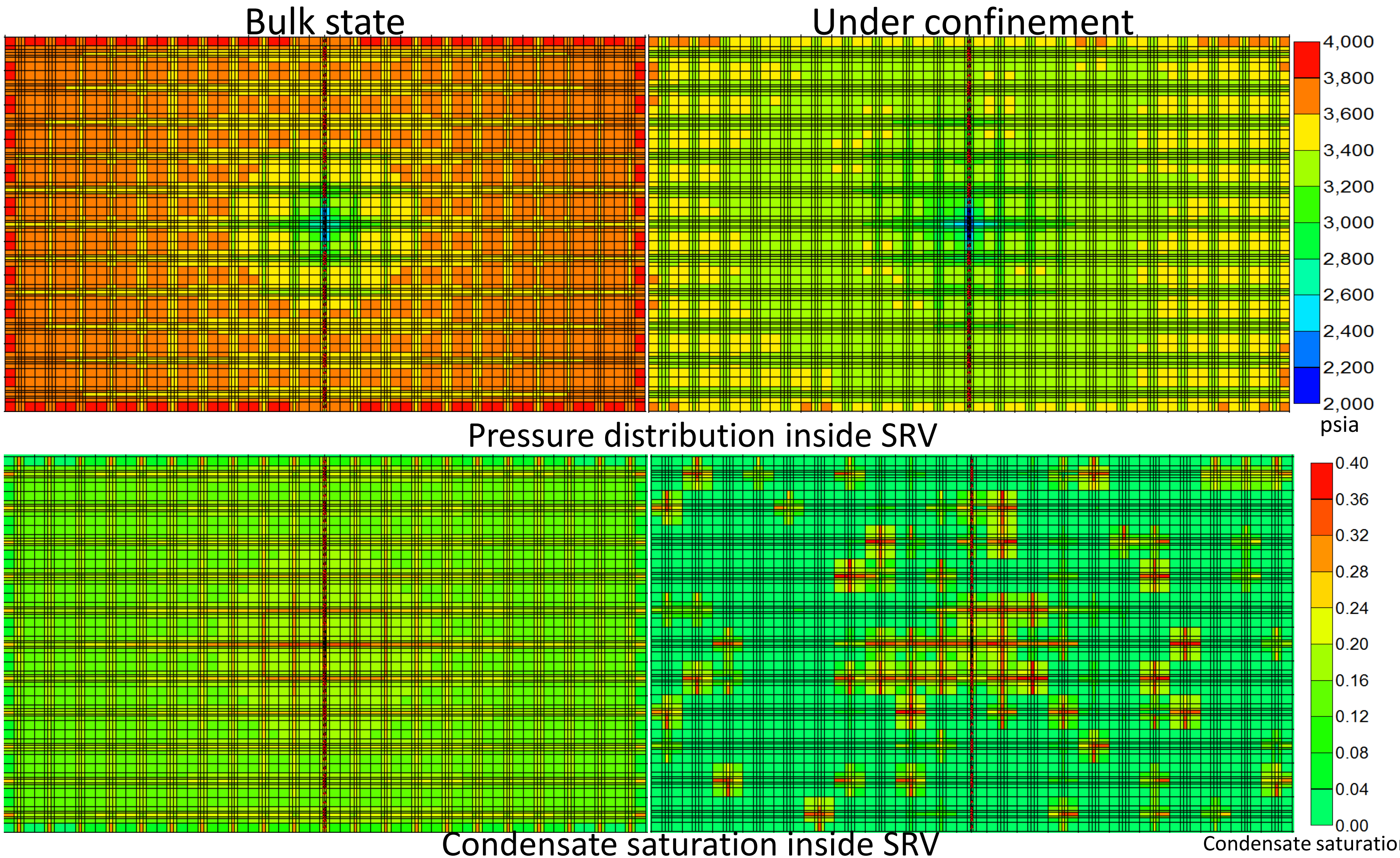


# Pore size distribution

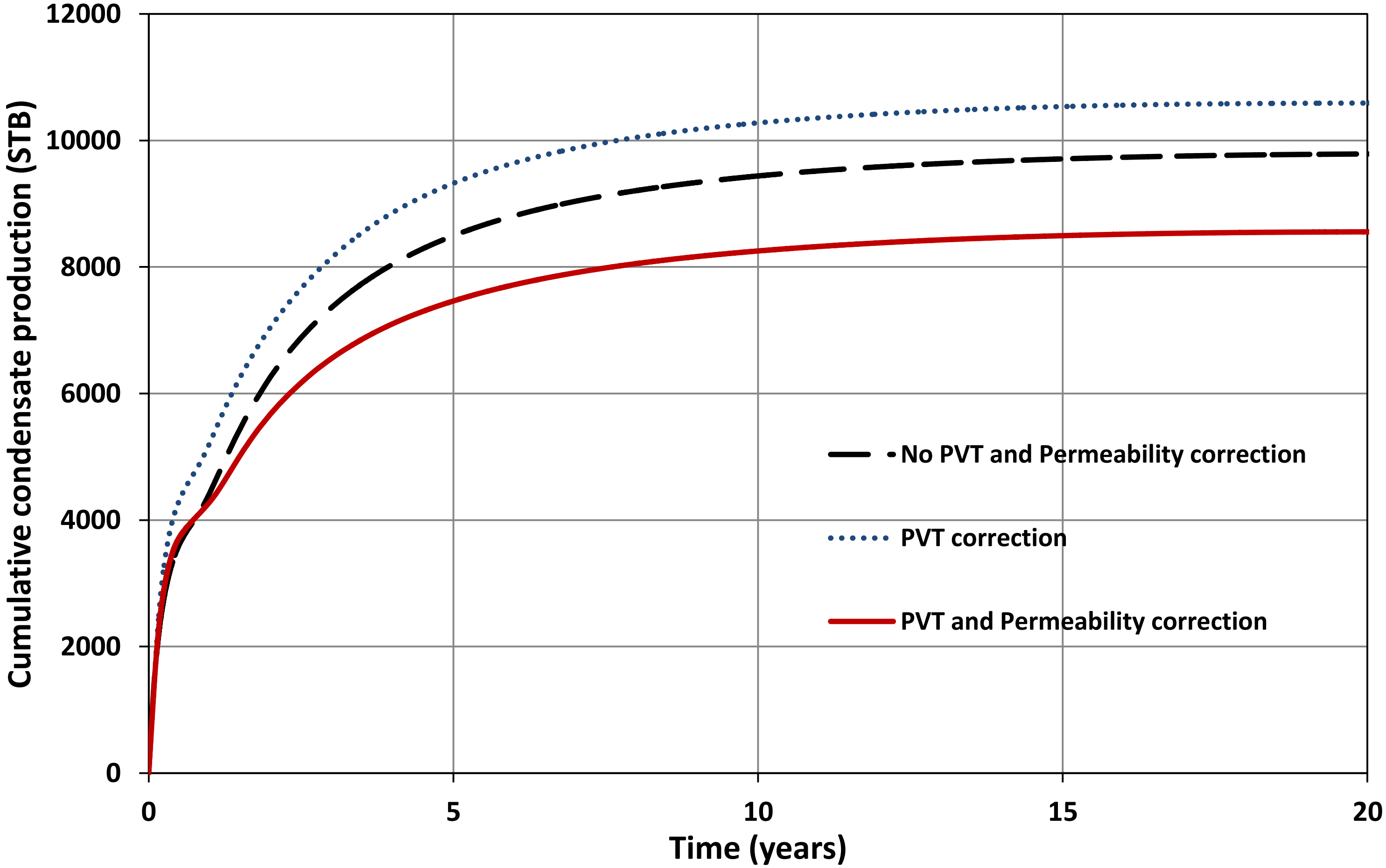



**500*620*60 ft$^3$**

# Confinement effect

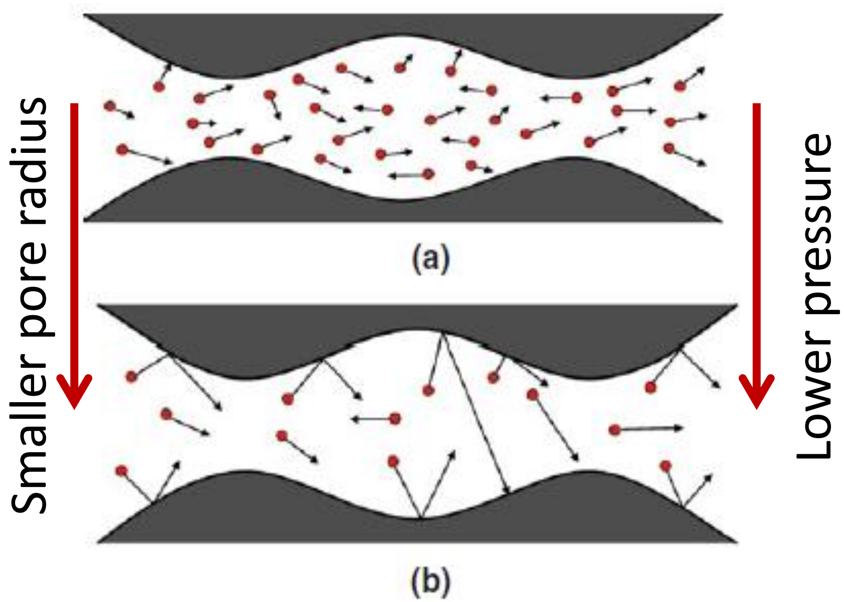


# PVT and Permeability correction effect

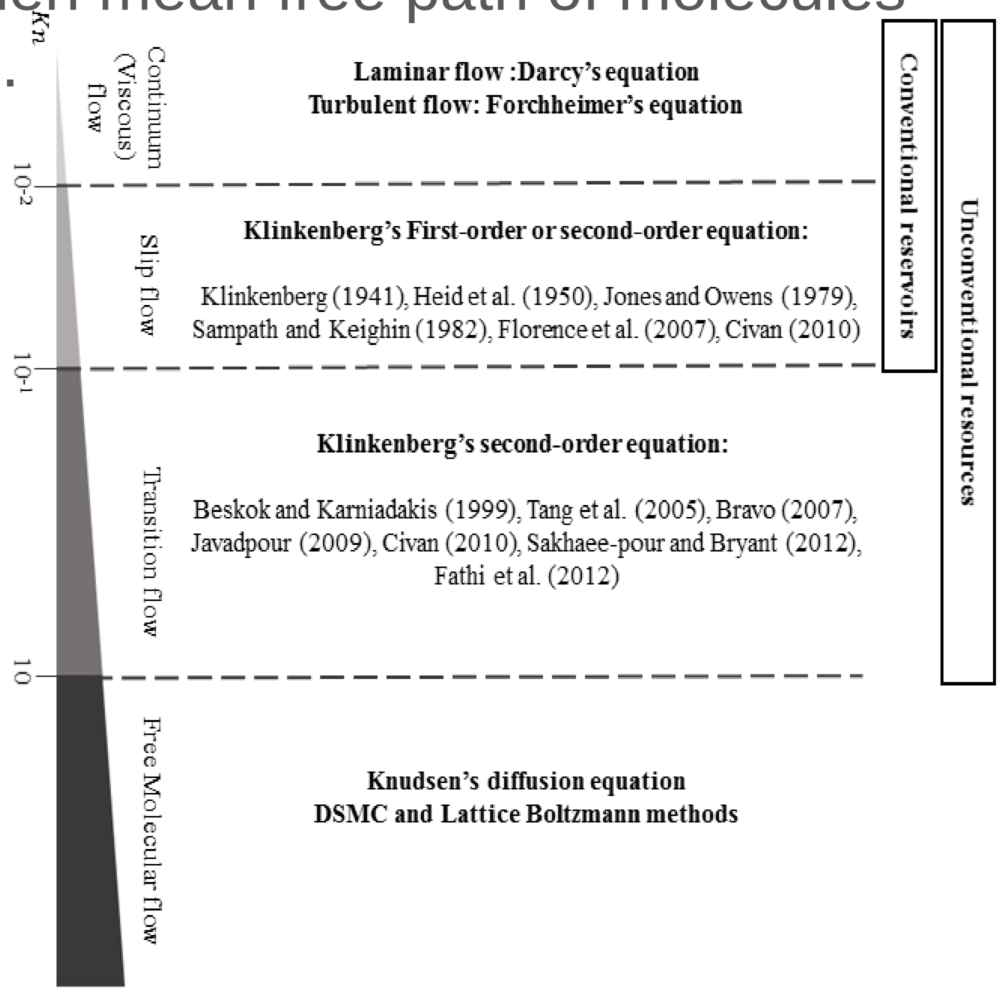


# Effect of non-Darcy flow

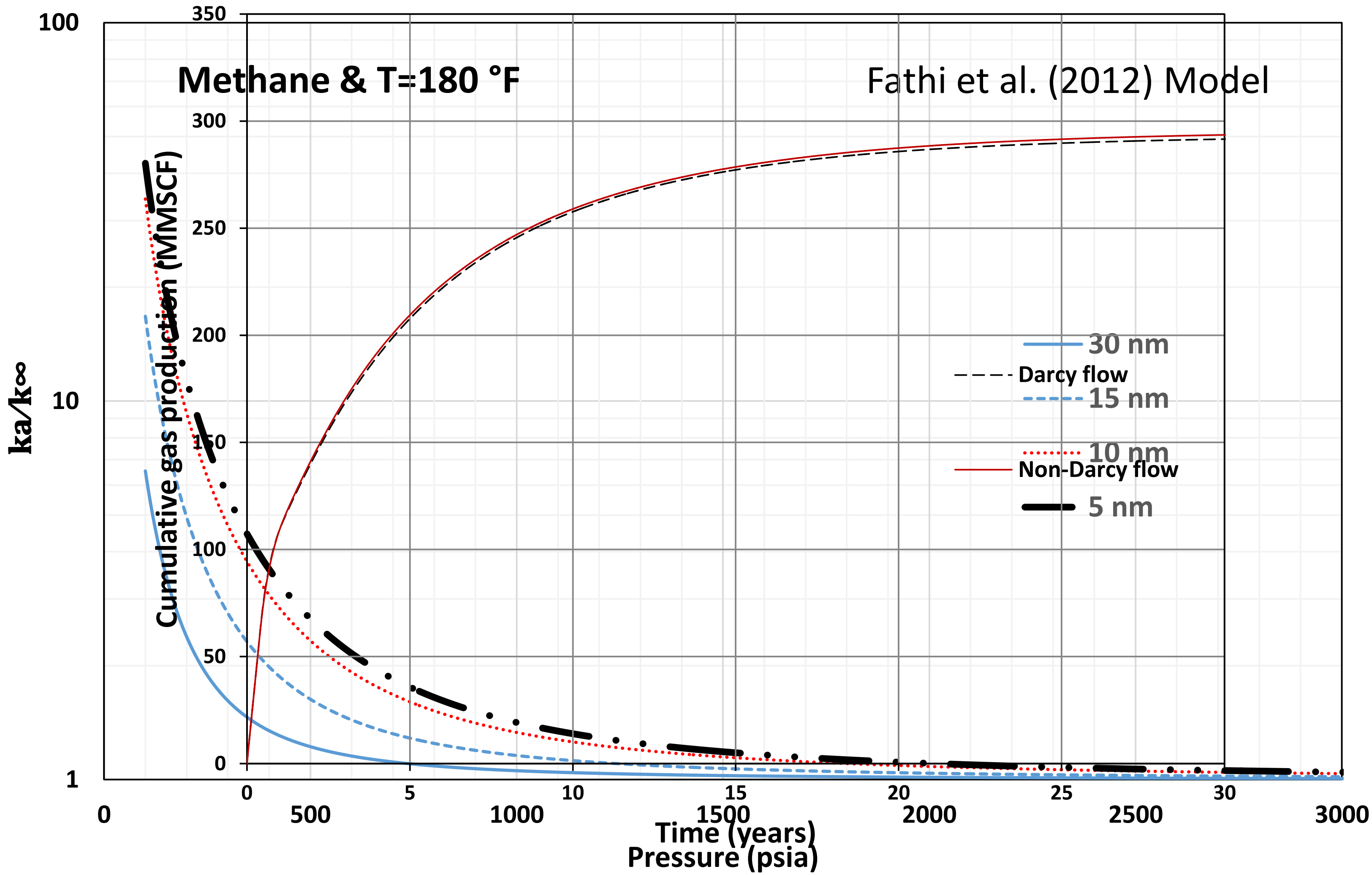
- Non-Darcy flow occurs when mean free path of molecules are in order of pore radius.




$$Kn = \frac{\lambda}{d}$$



# Effect of non-Darcy flow



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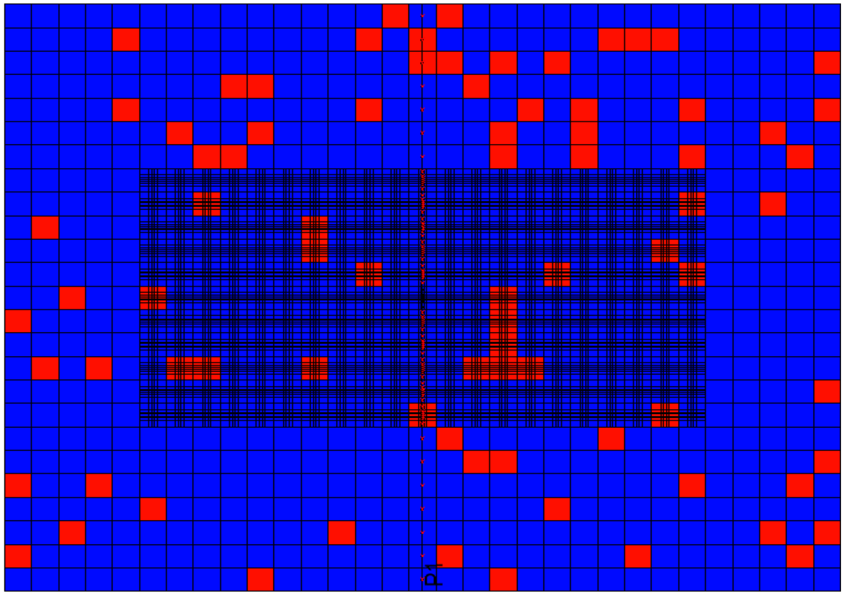
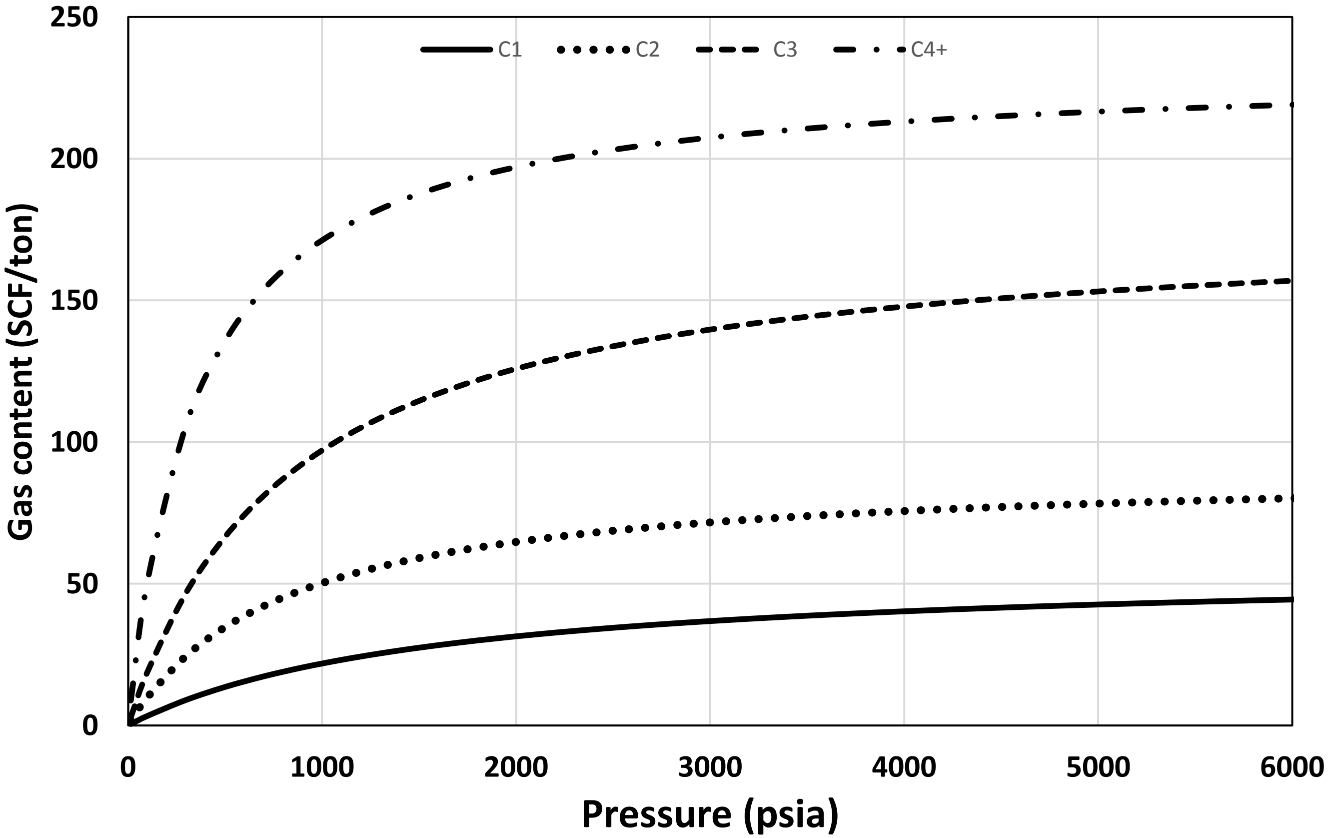
# Desorption mechanism

- Gas exists in both adsorbed and free phase in shale resources
- TOC in Eagle Ford: 3-7 wt.%
- Considered TOC: 5wt.%
- Randomly distributed in the model



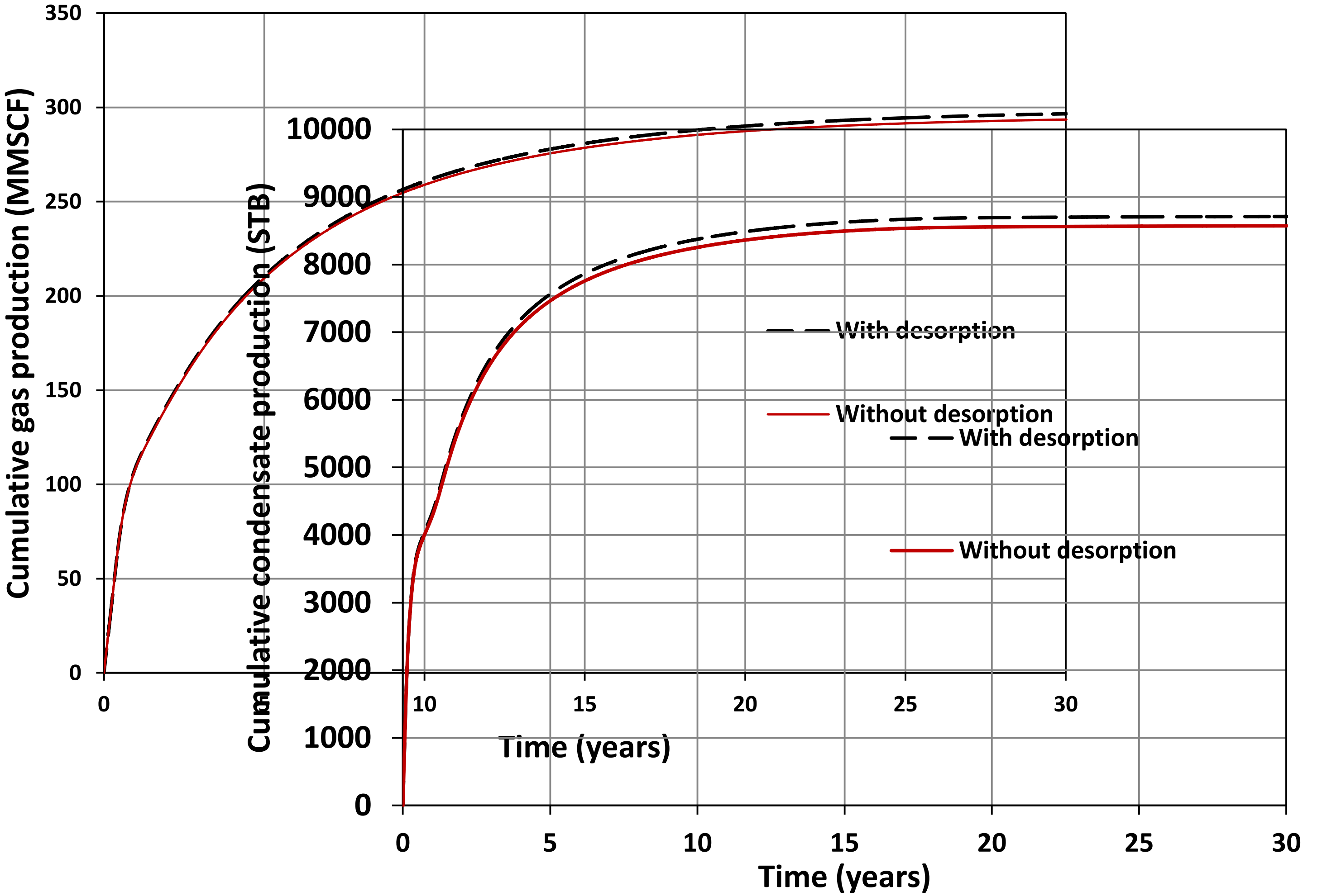
# Desorption mechanism

- Extended Langmuir isotherm model

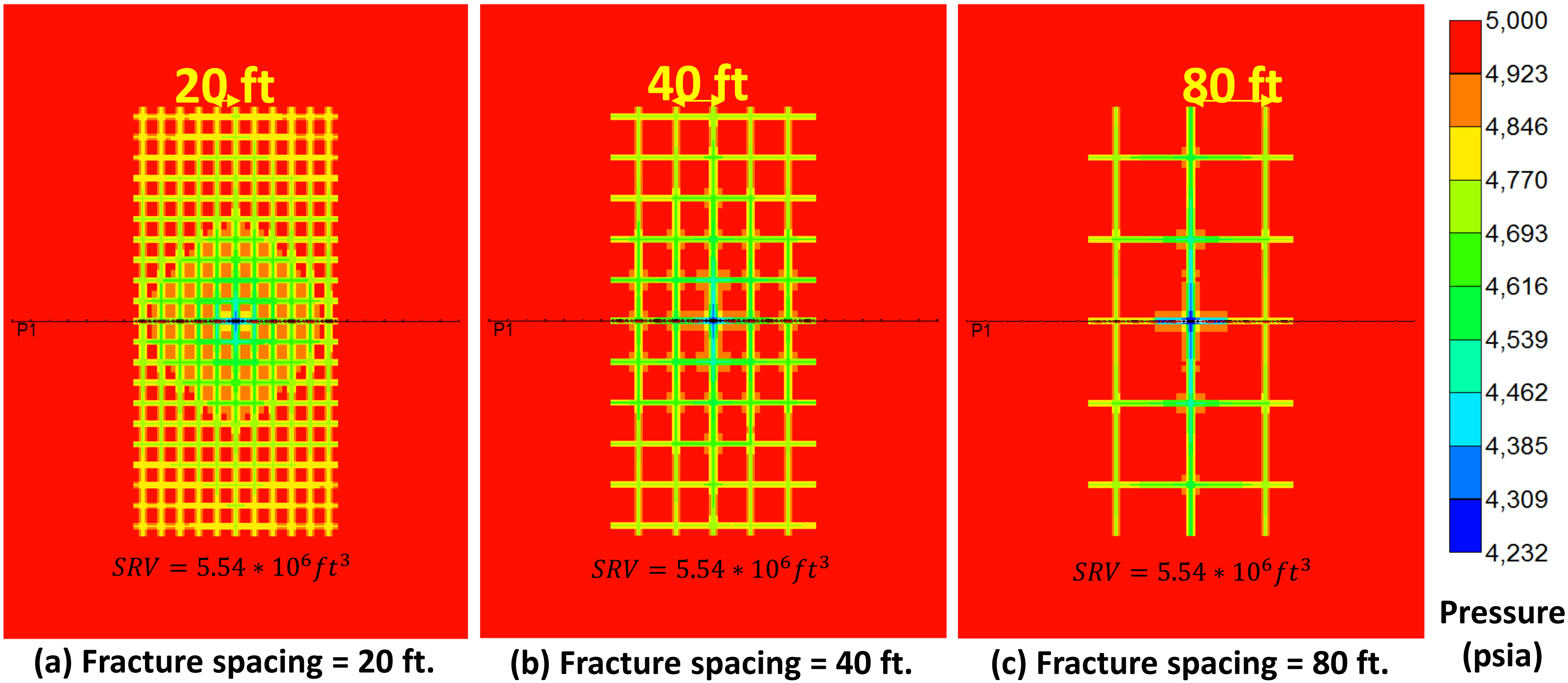



Ambrose et al., 2011

# Desorption Modeling

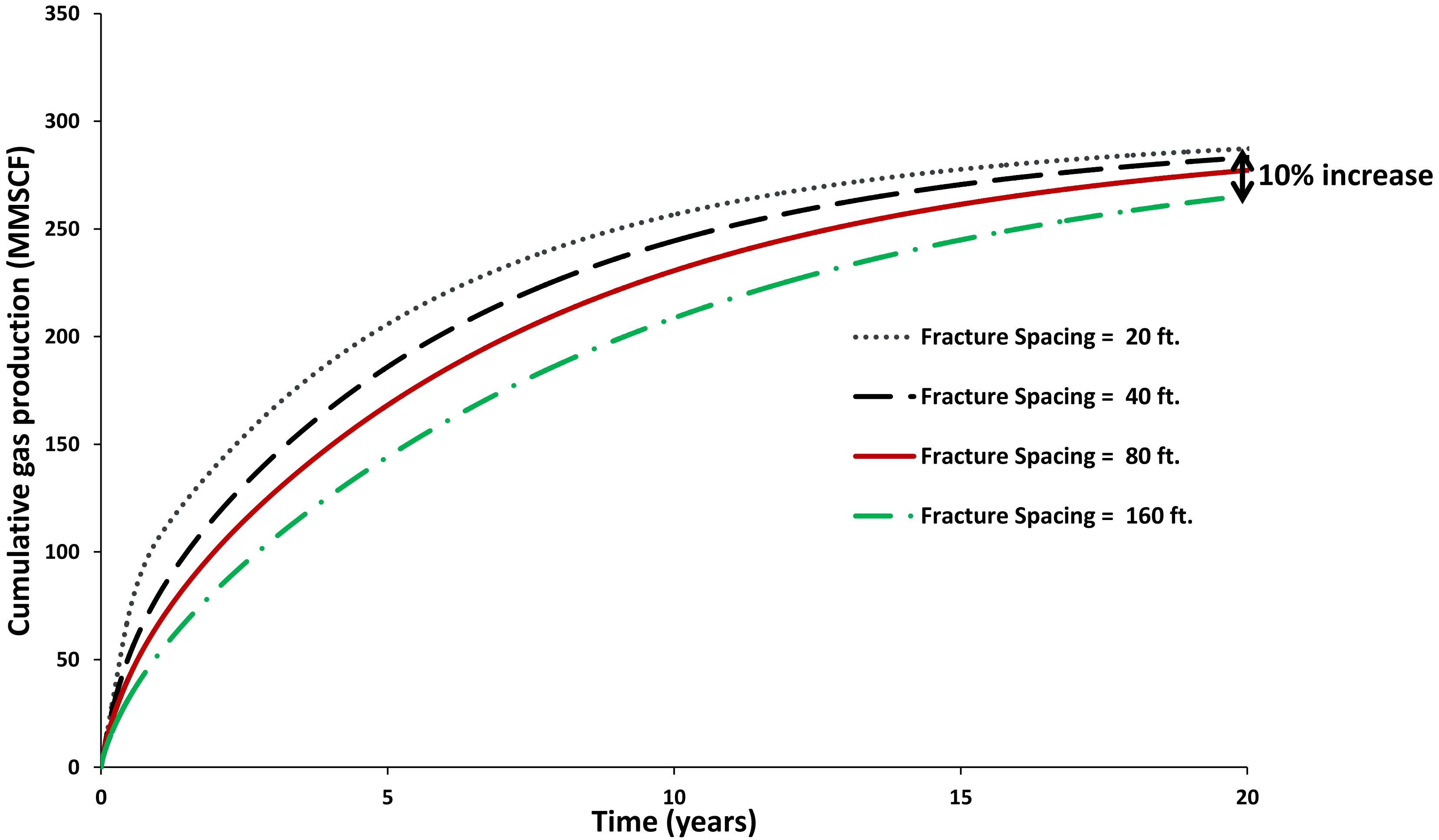


# Fracture density effect

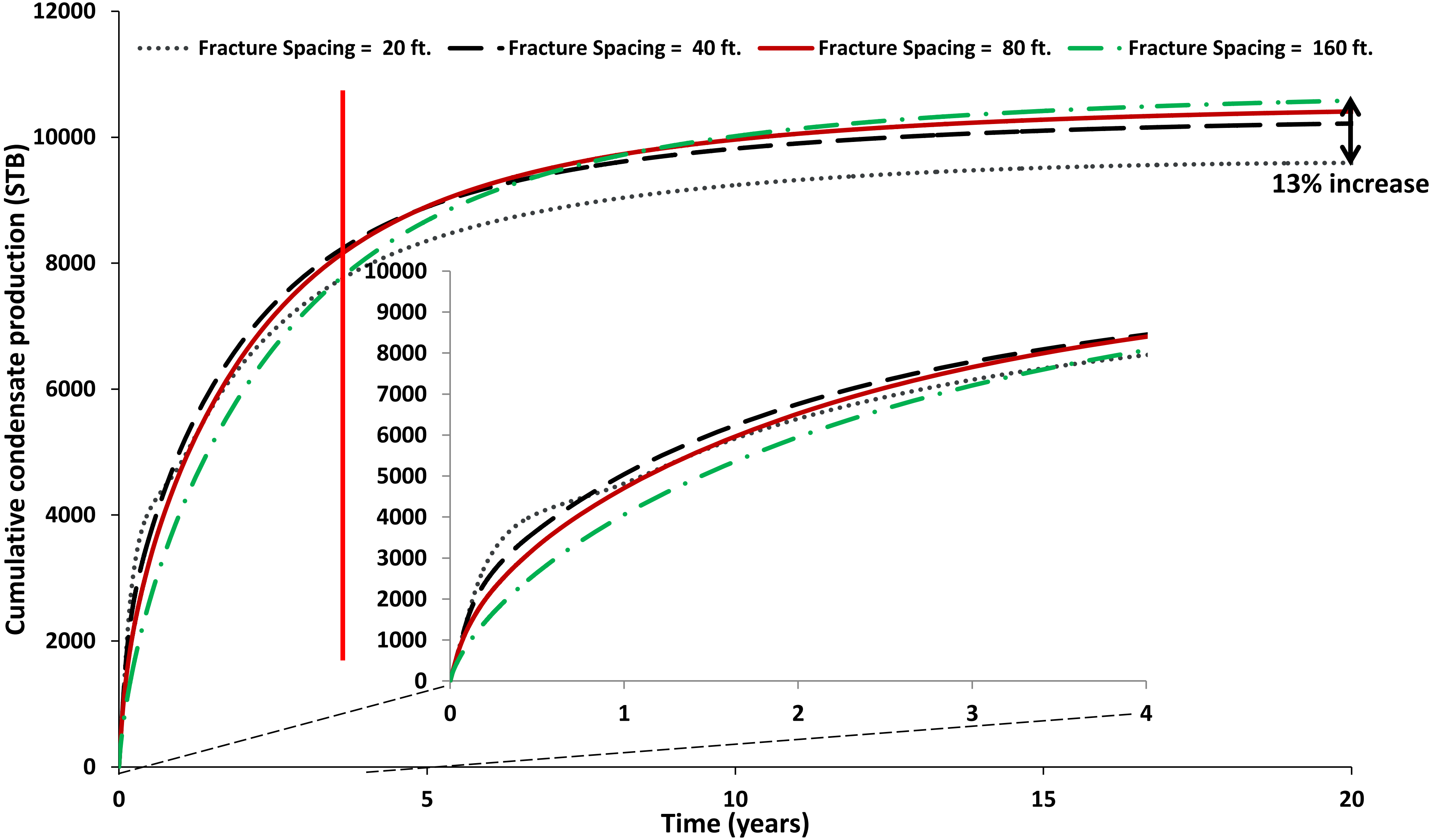



**(a) Fracture spacing = 20 ft.** **(b) Fracture spacing = 40 ft.** **(c) Fracture spacing = 80 ft.**

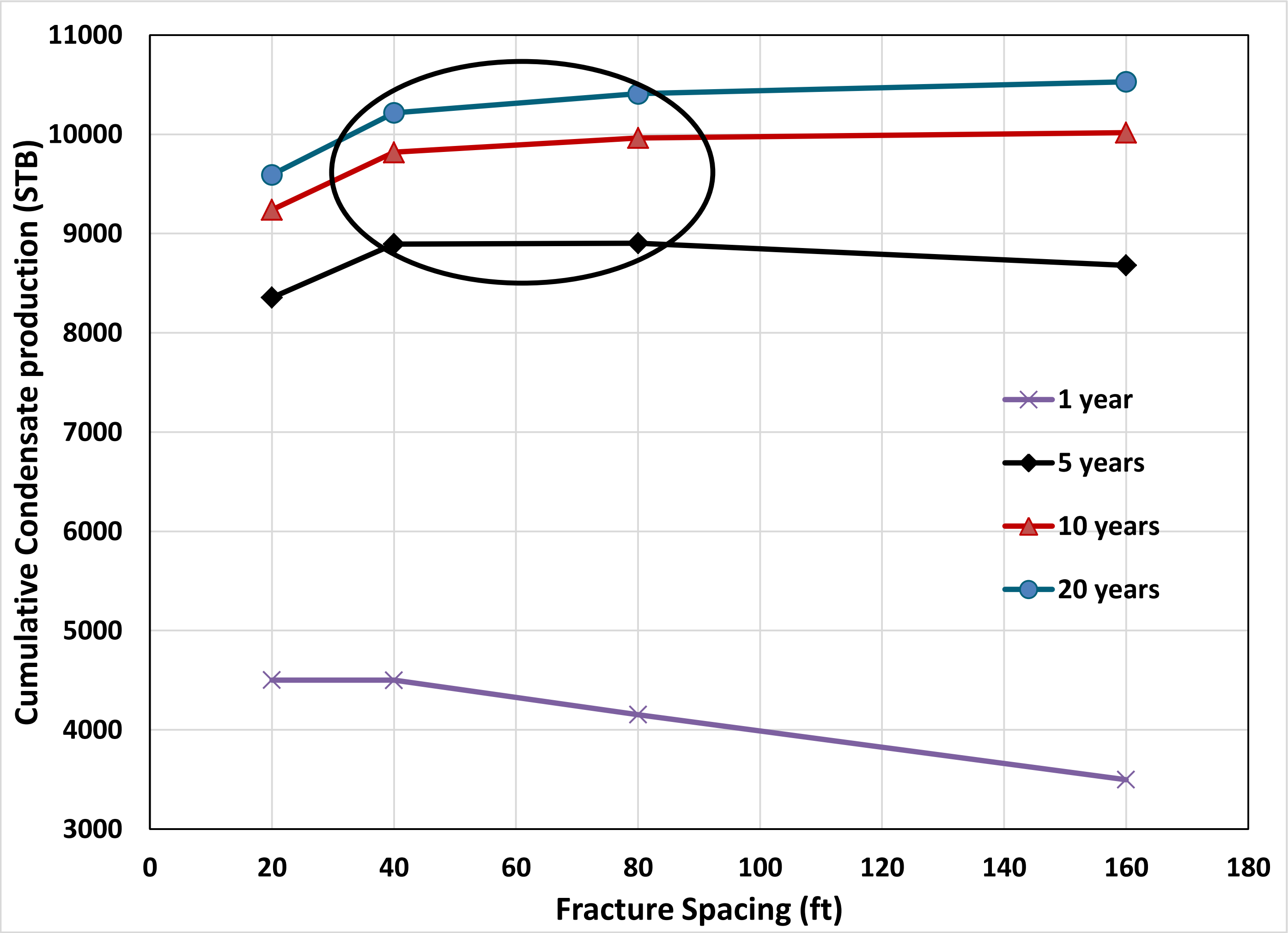
# Fracture density effect



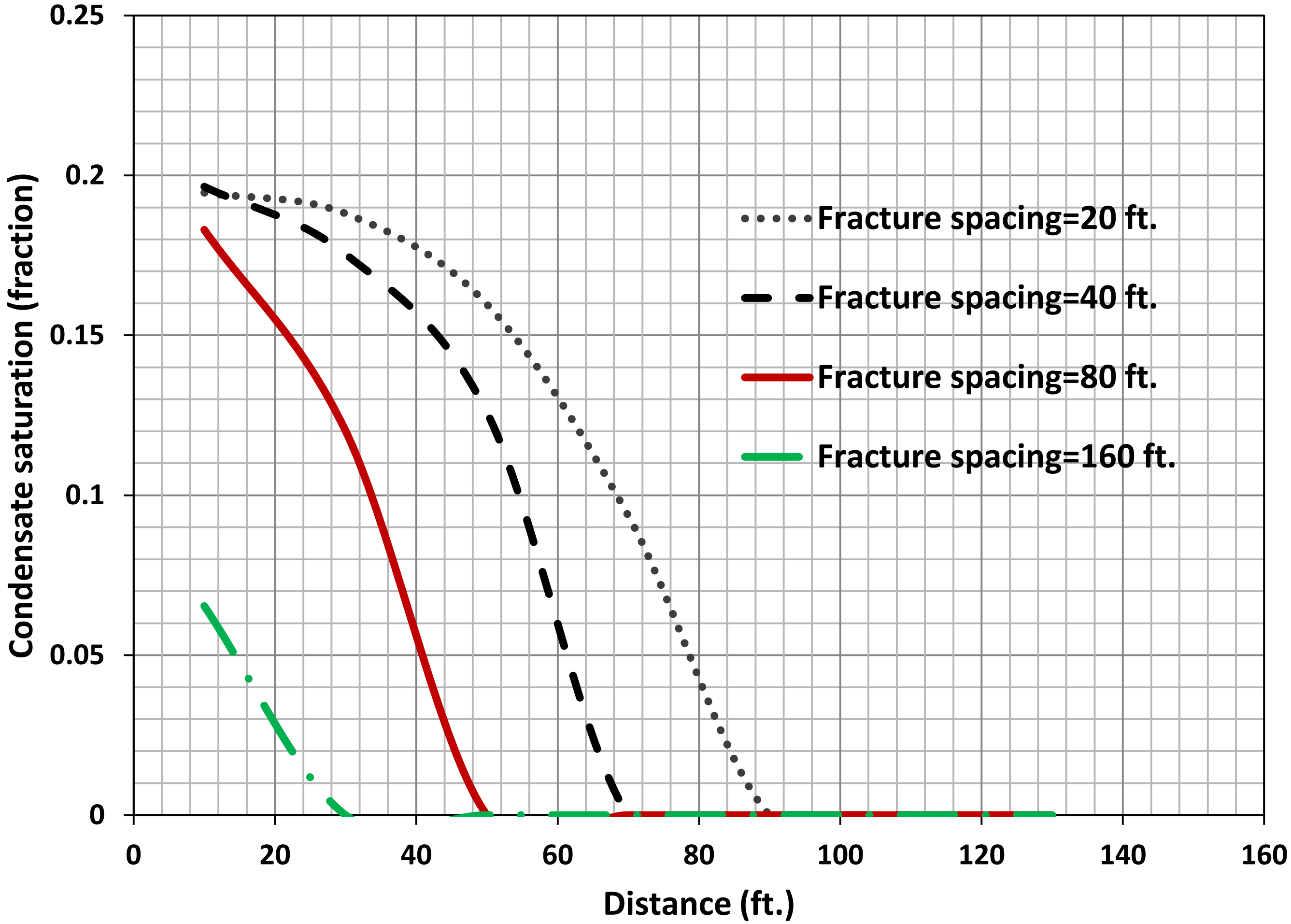
# Fracture density effect



# Fracture density effect



# Condensate drop-out




1 year

# Conclusions

- Considering phase behavior modification in nanopores has a positive impact on condensate production while applying permeability distribution has a negative impact on production.

- Non-Darcy flow does not have significant impact on production at high pressures. This effect becomes quite significant for laboratory low operational pressures.

- Desorption has a negligible effect on gas and condensate production from this reservoir.

- Increasing fracture density improves cumulative gas production and short term cumulative condensate production forecasts. But, the long term cumulative condensate production decreased as the fracture density increased.

# Acknowledgements / Thank You / Questions

Unconventional Shale Gas research group at University of Oklahoma

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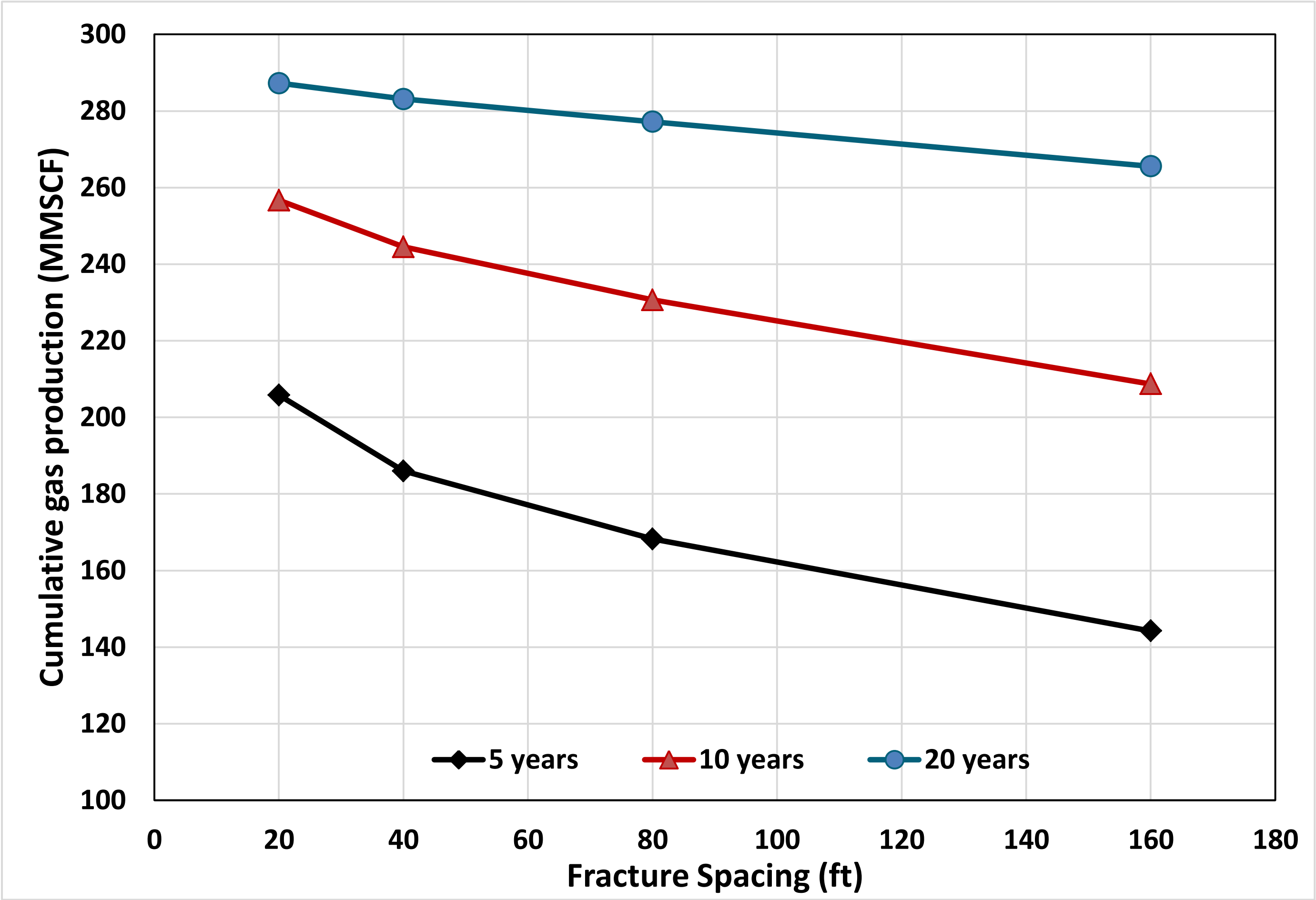
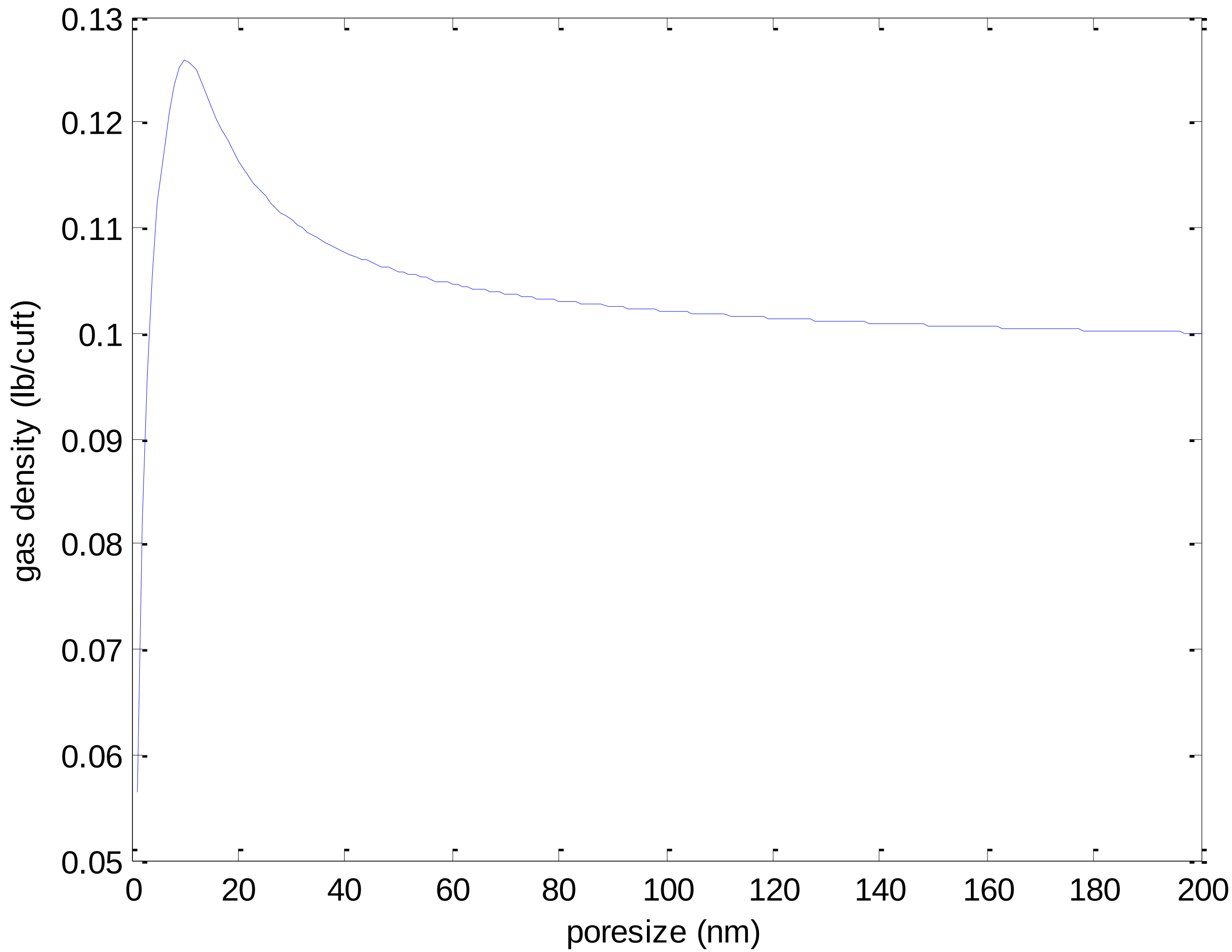
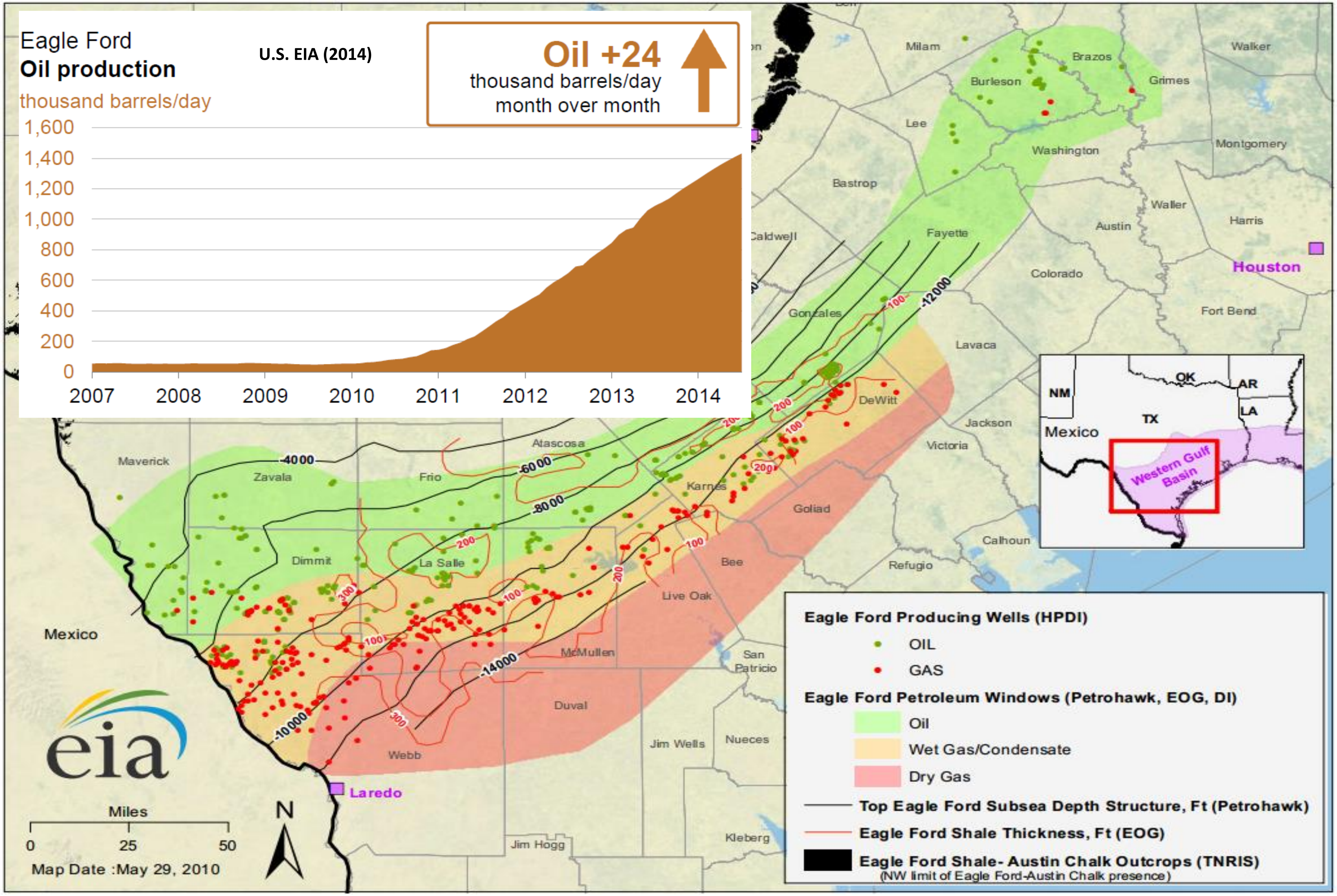
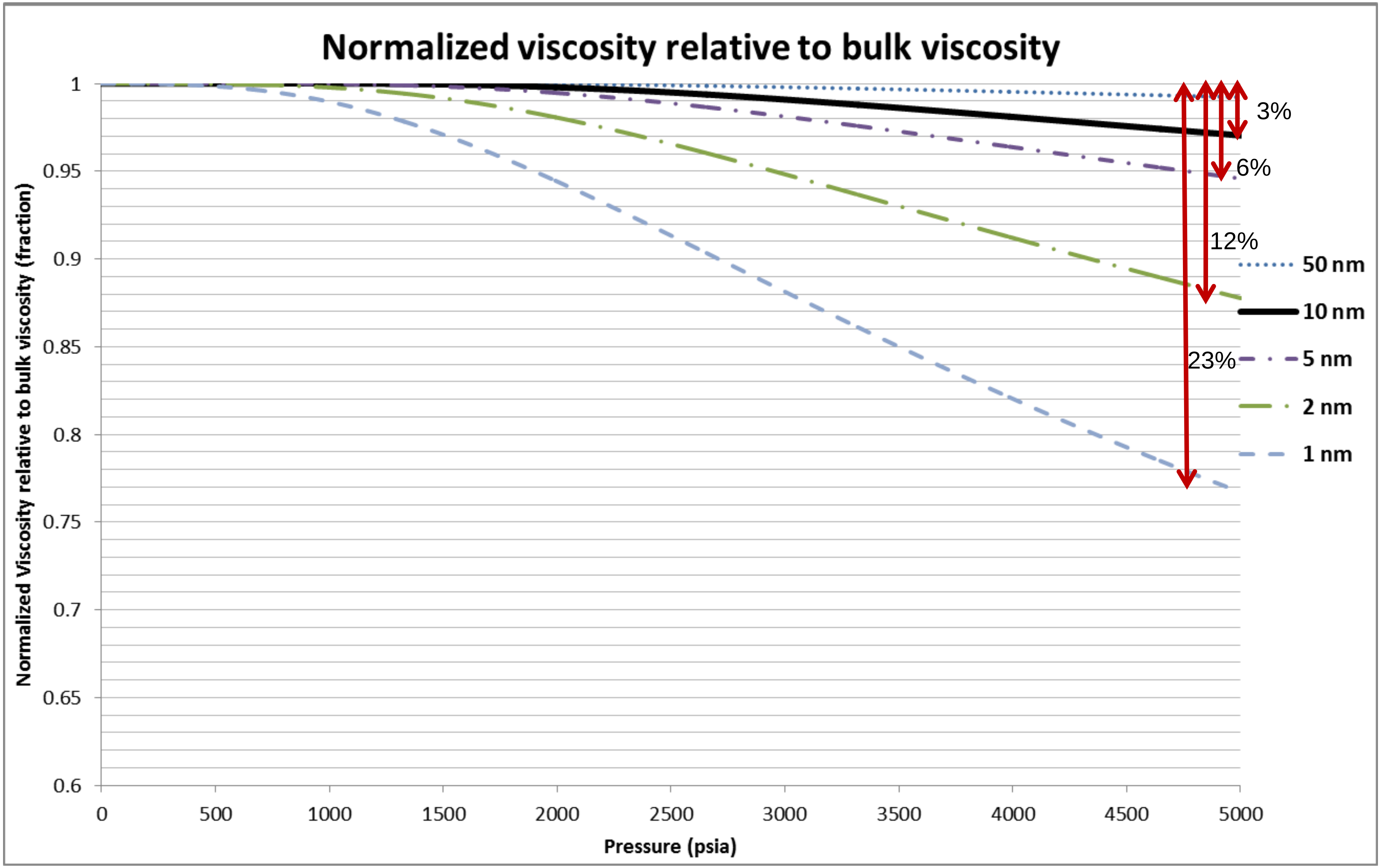

Cumulative gas production (MMSCF)
300
280
260
240
220
200
180
160
140
120
100
0
20
40
60
80
100
120
140
160
180
Fracture Spacing (ft)
5 years
10 years
20 years

- Pore proximity effect on ethane density @ p=600 psi , T=28 ° C

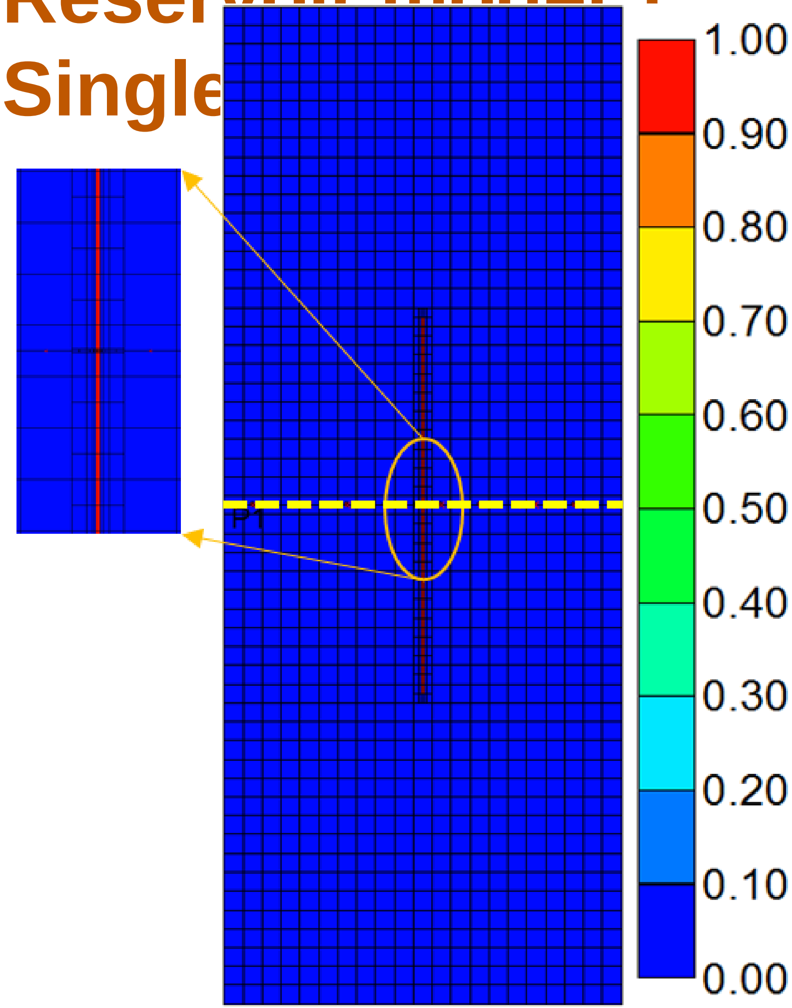



Eagle Ford
Oil production
thousand barrels/day
U.S. EIA (2014)
Oil +24
thousand barrels/day
month over month
1,600
1,400
1,200
1,000
800
600
400
200
0
2007
2008
2009
2010
2011
2012
2013
2014
Milam
Brazos
Walker
Burleson
Grimes
Lee
Washington
Montgomery
Bastrop
Waller
Harris
Caldwell
Fayette
Austin
Colorado
Houston
Gonzales
Fort Bend
Lavaca
DeWitt
Jackson
Victoria
Maverick
Atascosa
Zavala
Frio
Karnes
Goliad
Calhoun
Dimmit
La Salle
Bee
Refugio
Live Oak
Mexico
McMullen
San Patricio
Duval
Jim Wells
Nueces
Webb
Laredo
Jim Hogg
Kleberg
NM
OK
AR
LA
TX
Mexico
Western Gulf Basin
-4000
-6000
-8000
-10000
-12000
-14000
100
200
300
Miles
0
25
50
N
Map Date :May 29, 2010
Eagle Ford Producing Wells (HPDI)
OIL
GAS
Eagle Ford Petroleum Windows (Petrohawk, EOG, DI)
Oil
Wet Gas/Condensate
Dry Gas
Top Eagle Ford Subsea Depth Structure, Ft (Petrohawk)
Eagle Ford Shale Thickness, Ft (EOG)
Eagle Ford Shale- Austin Chalk Outcrops (TNRIS)
(NW limit of Eagle Ford-Austin Chalk presence)

# Pore proximity effect on methane properties



# Reservoir model 1: Single




| Parameter | Value |
|---|---|
| Matrix permeability | 149 nD |
| Fracture conductivity | 2 mD-ft |
| Fracture half length | 250 ft. |
| Porosity | 9.4 % |
| Initial reservoir pressure | 5000 psi |
| Reservoir temperature | 180 F |
| Simulation time | 30 years |

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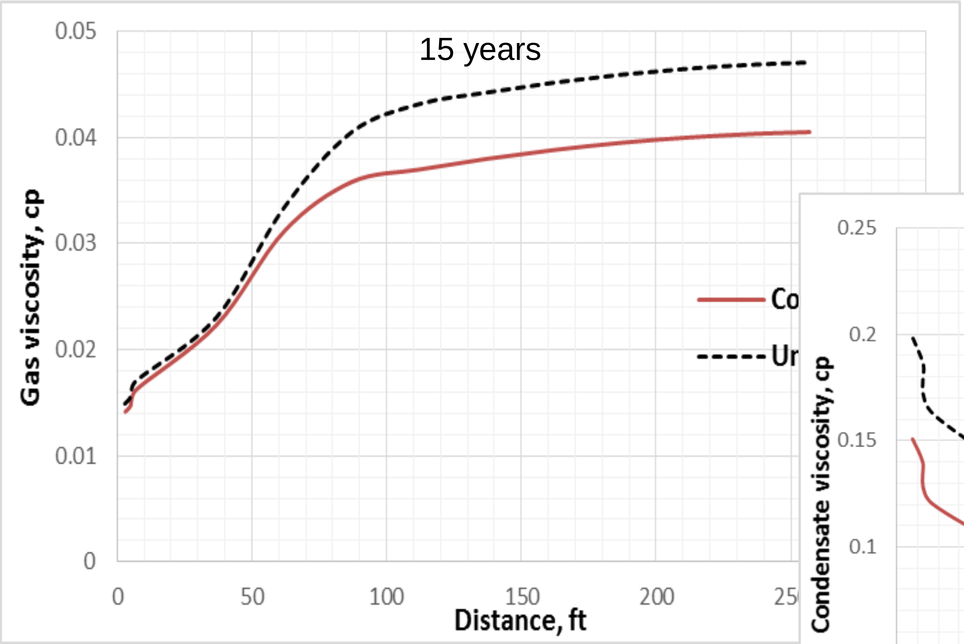
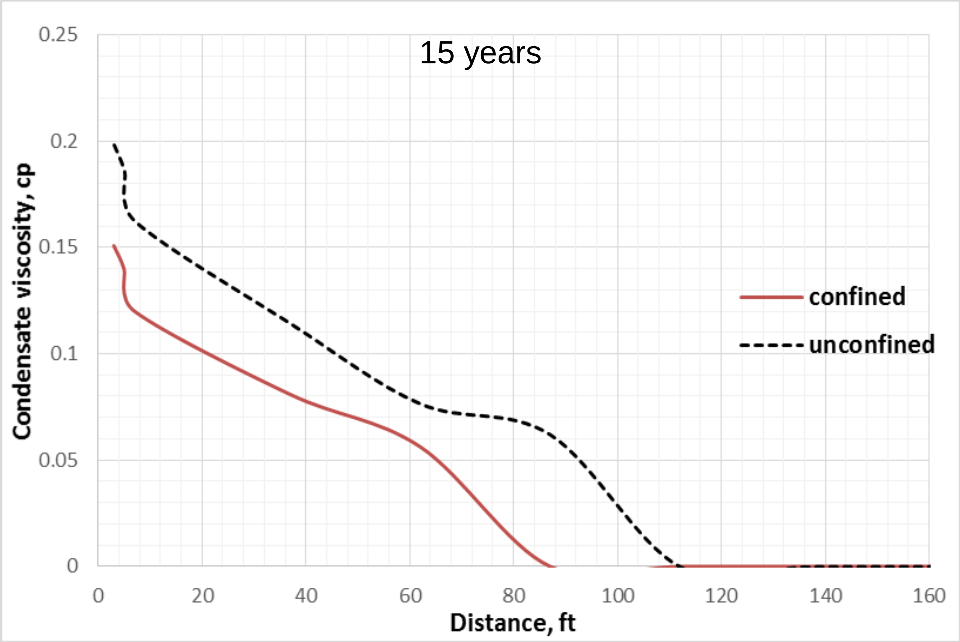
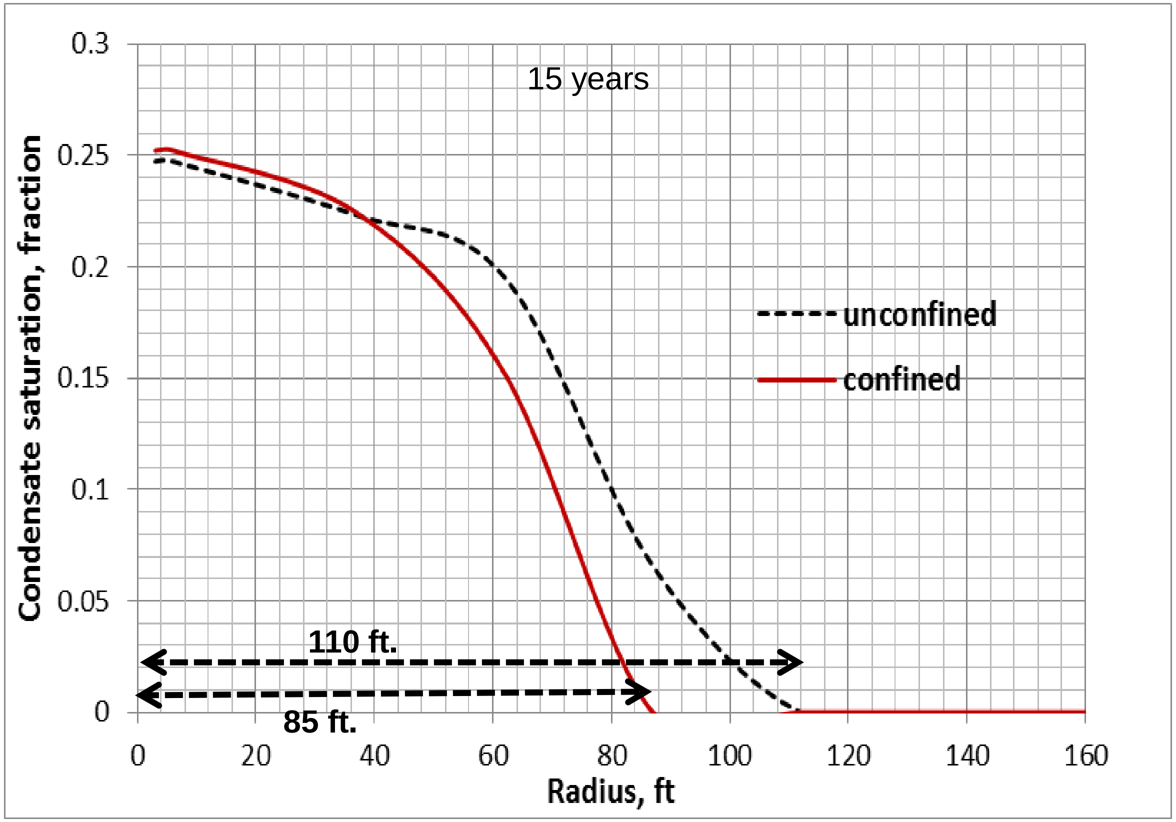
# Effect of confinement on condensate and gas viscosity profiles



# Effect of confinement on condensate saturation profile



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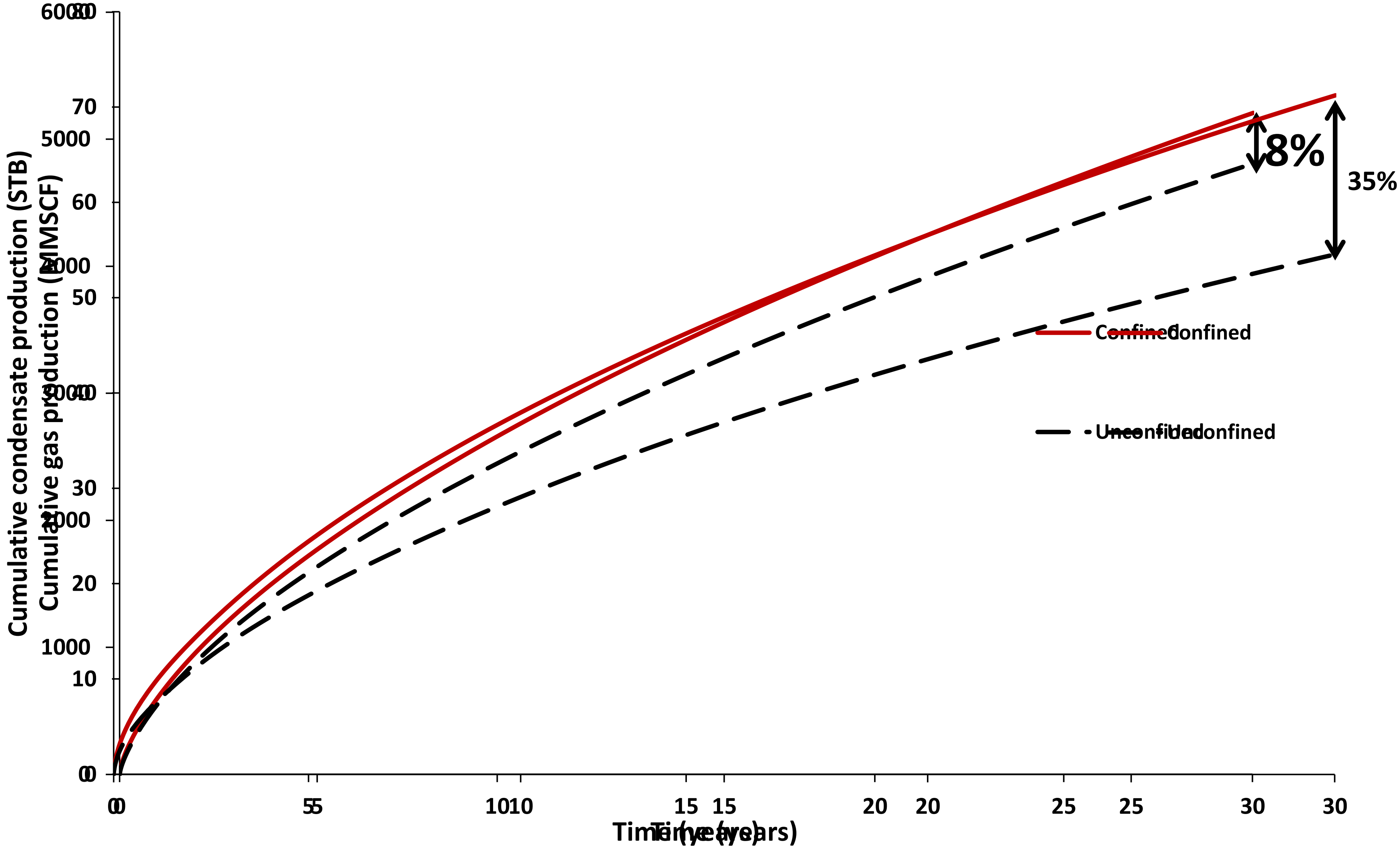
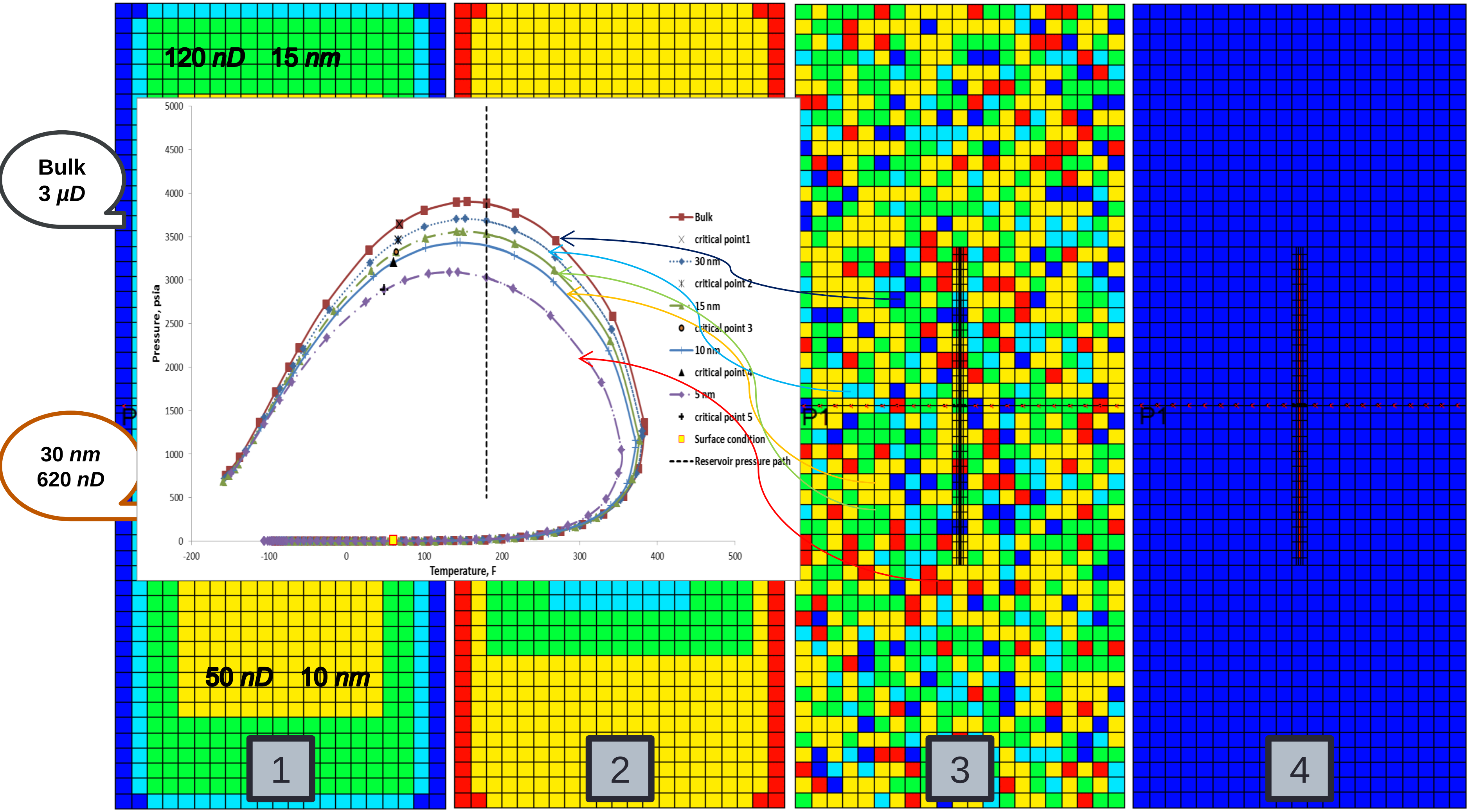
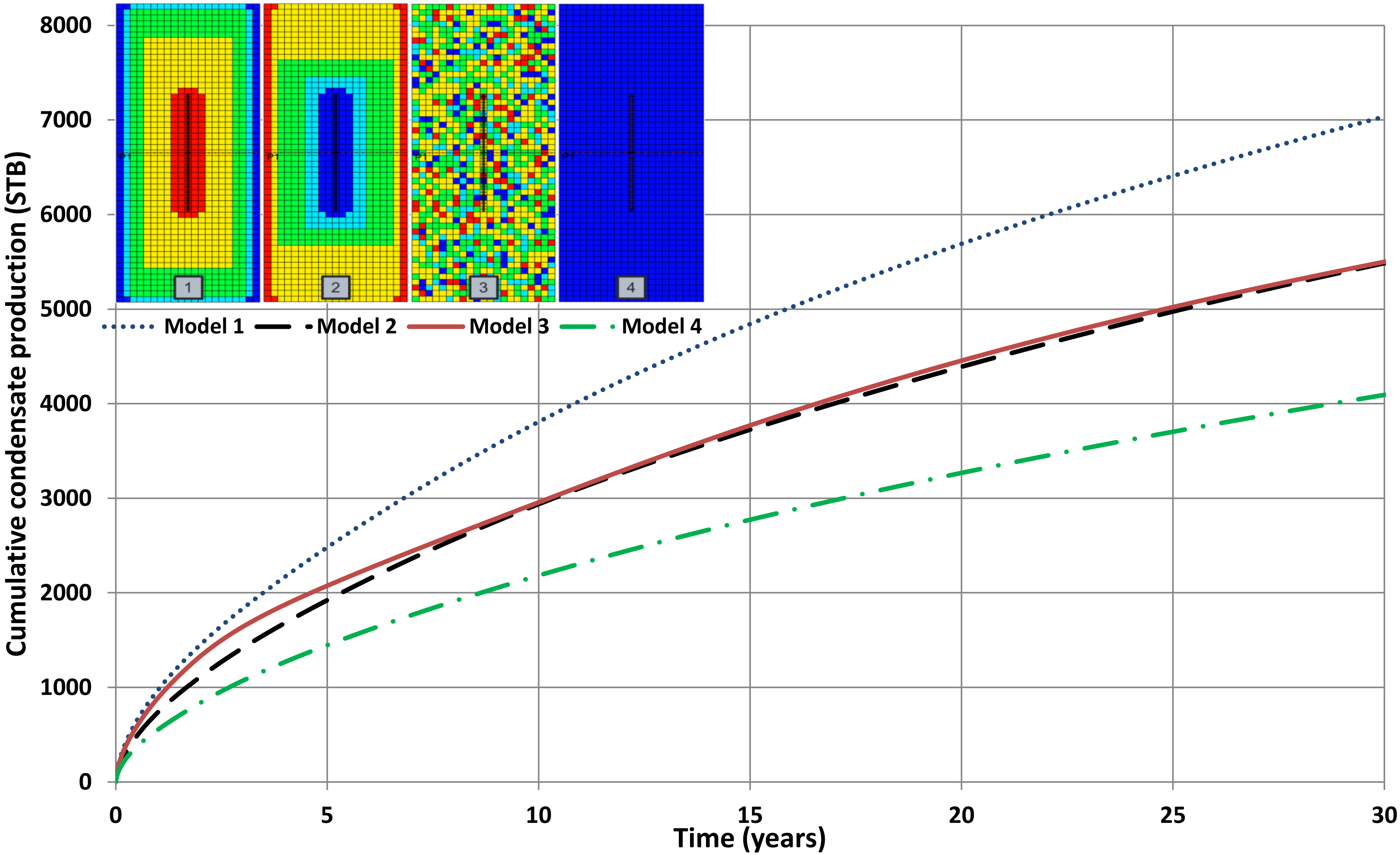
# Effect of confinement on production



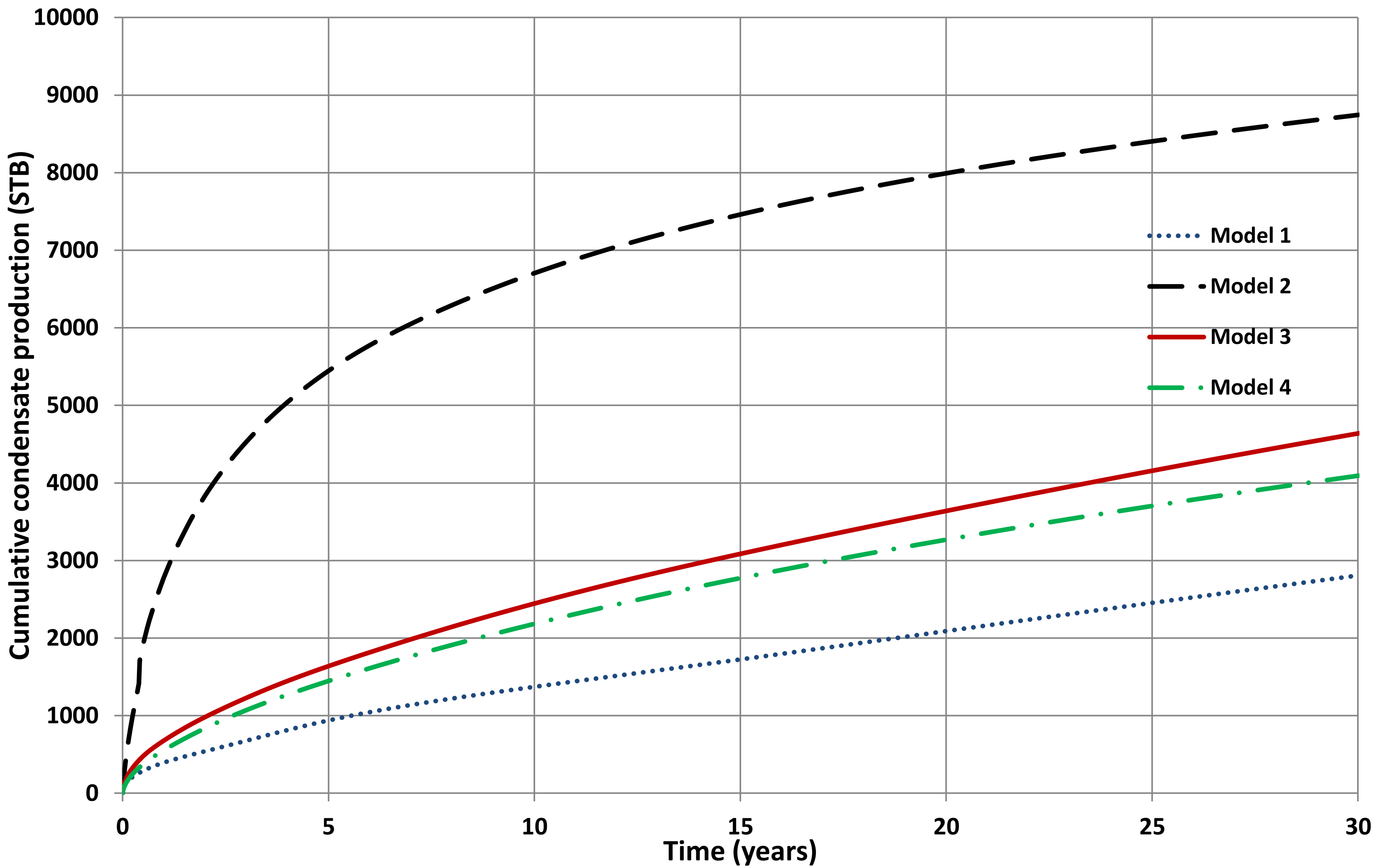
# Pore size variation and connectivity consideration



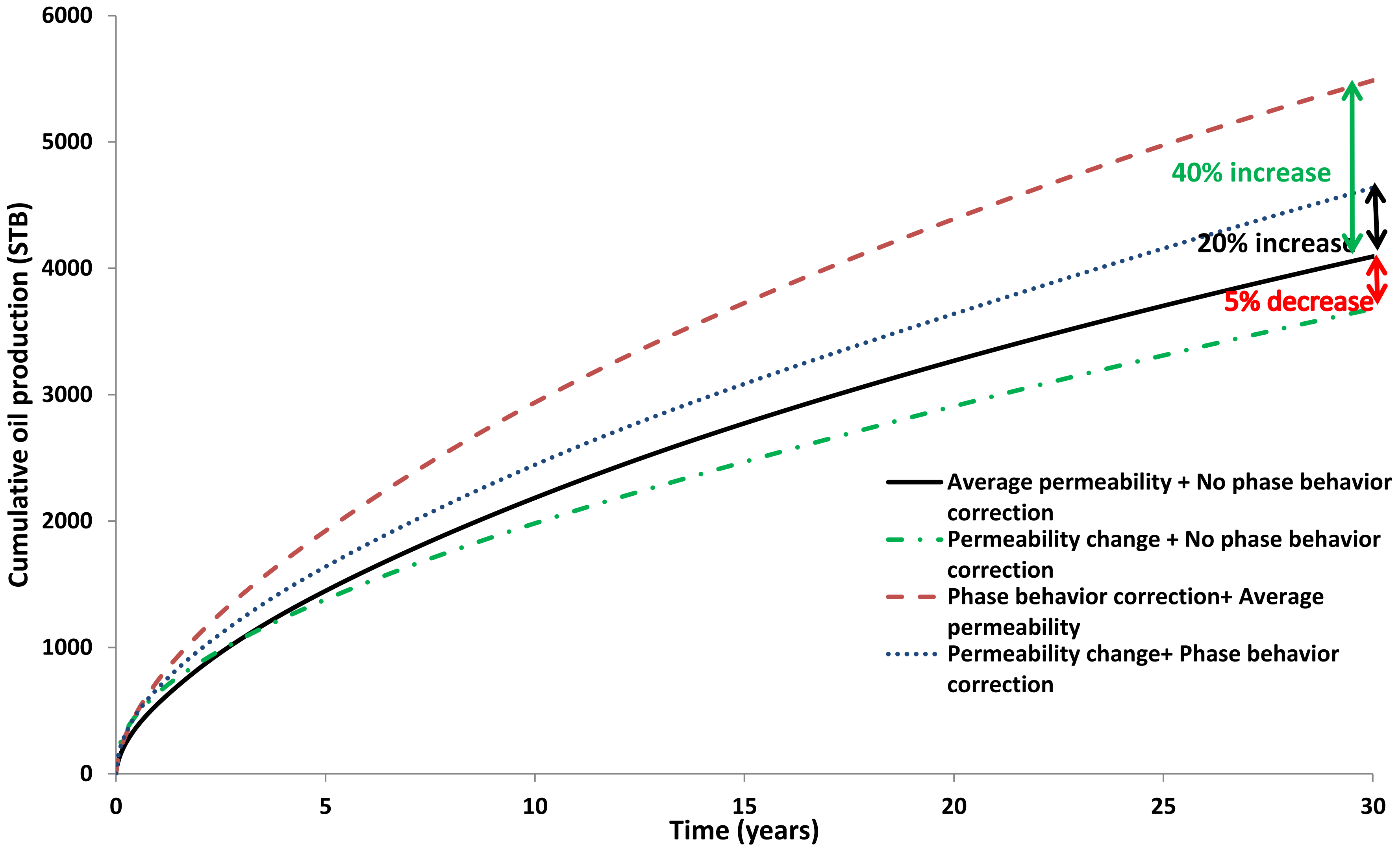
# Results: different PVT regions are considered



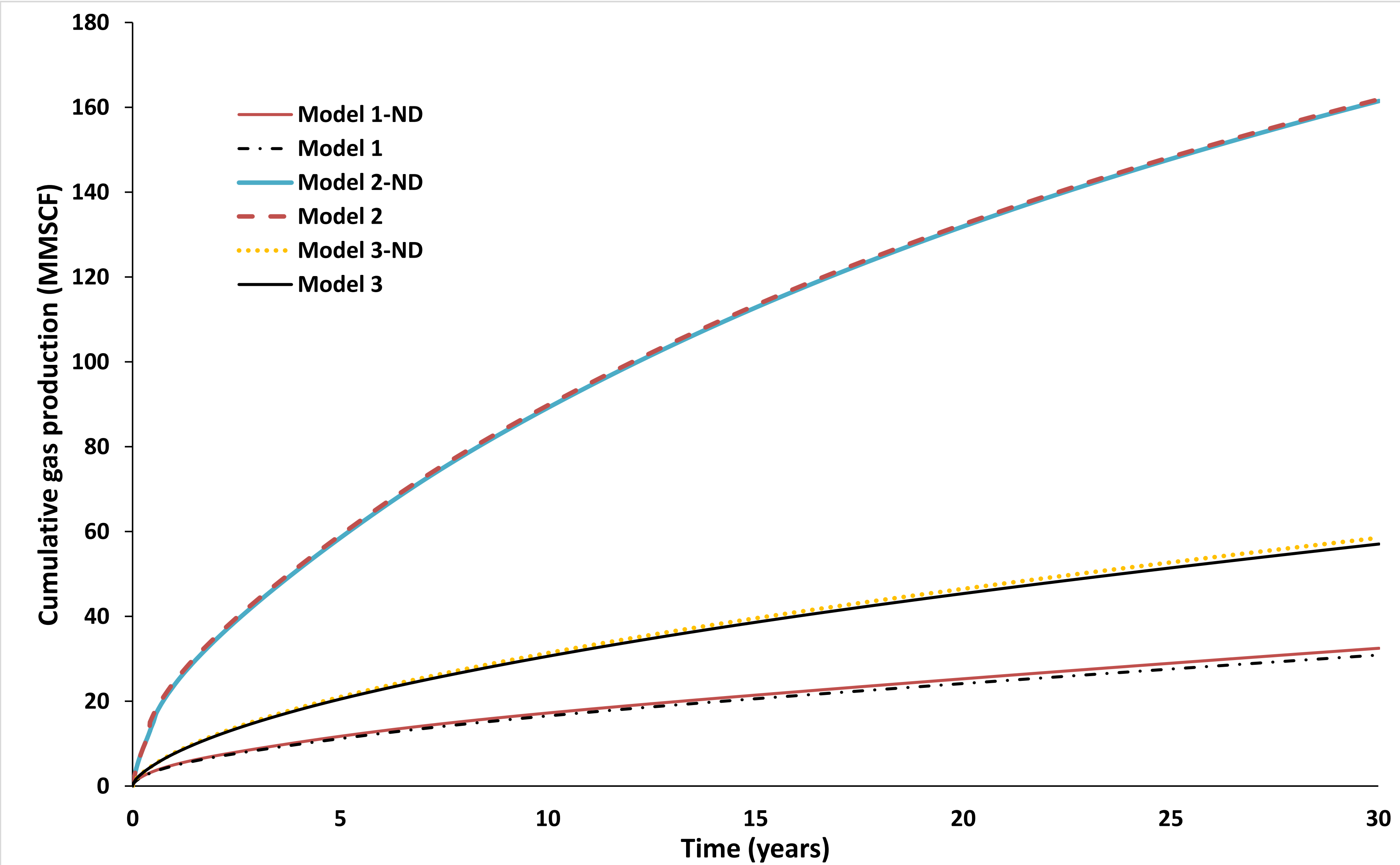
# Results: different PVT and permeability regions are considered



# Results: Effect of different parameters on Cumulative condensate production (Model 3)

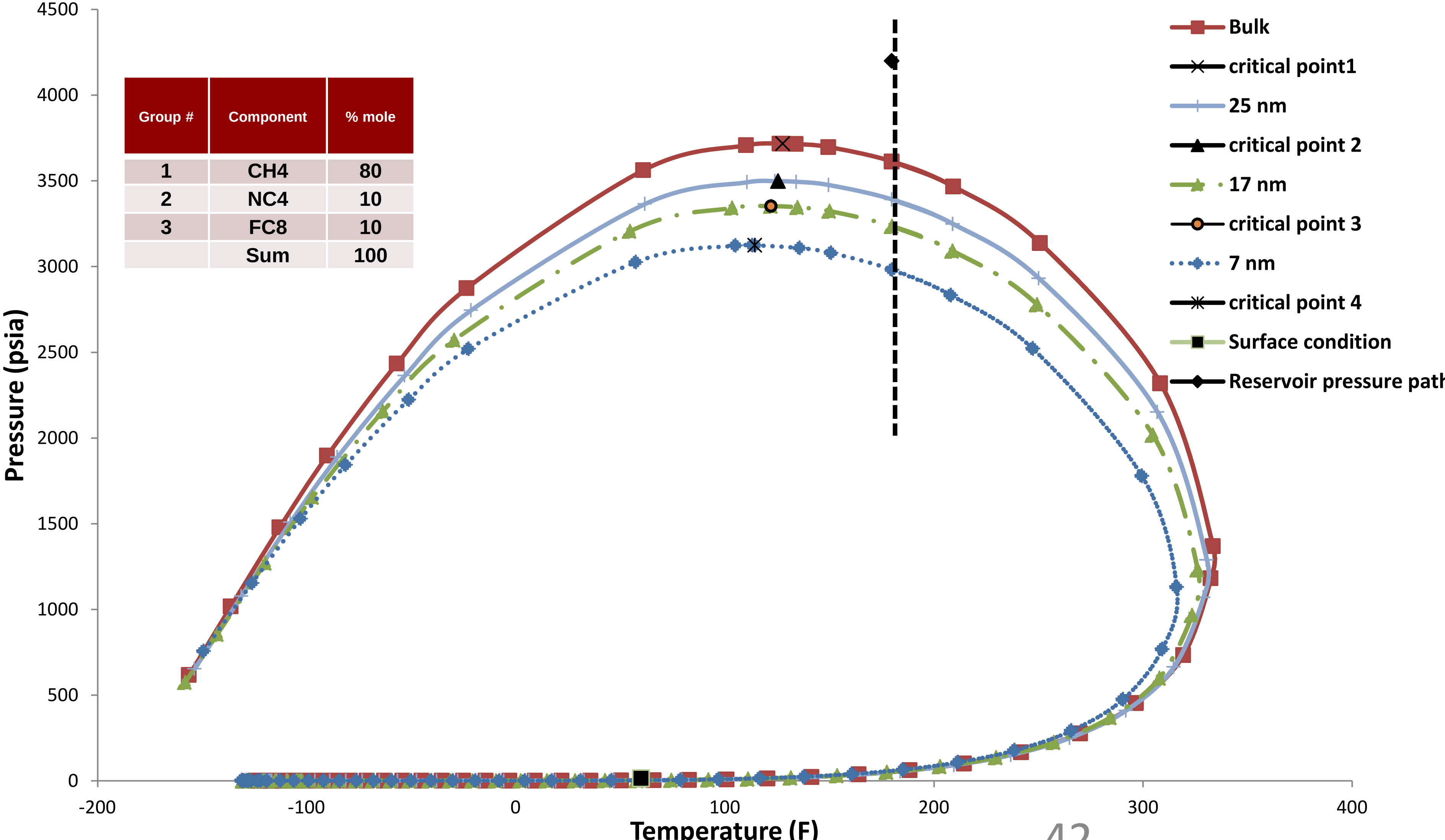


# Results: Effect of non-Darcy flow

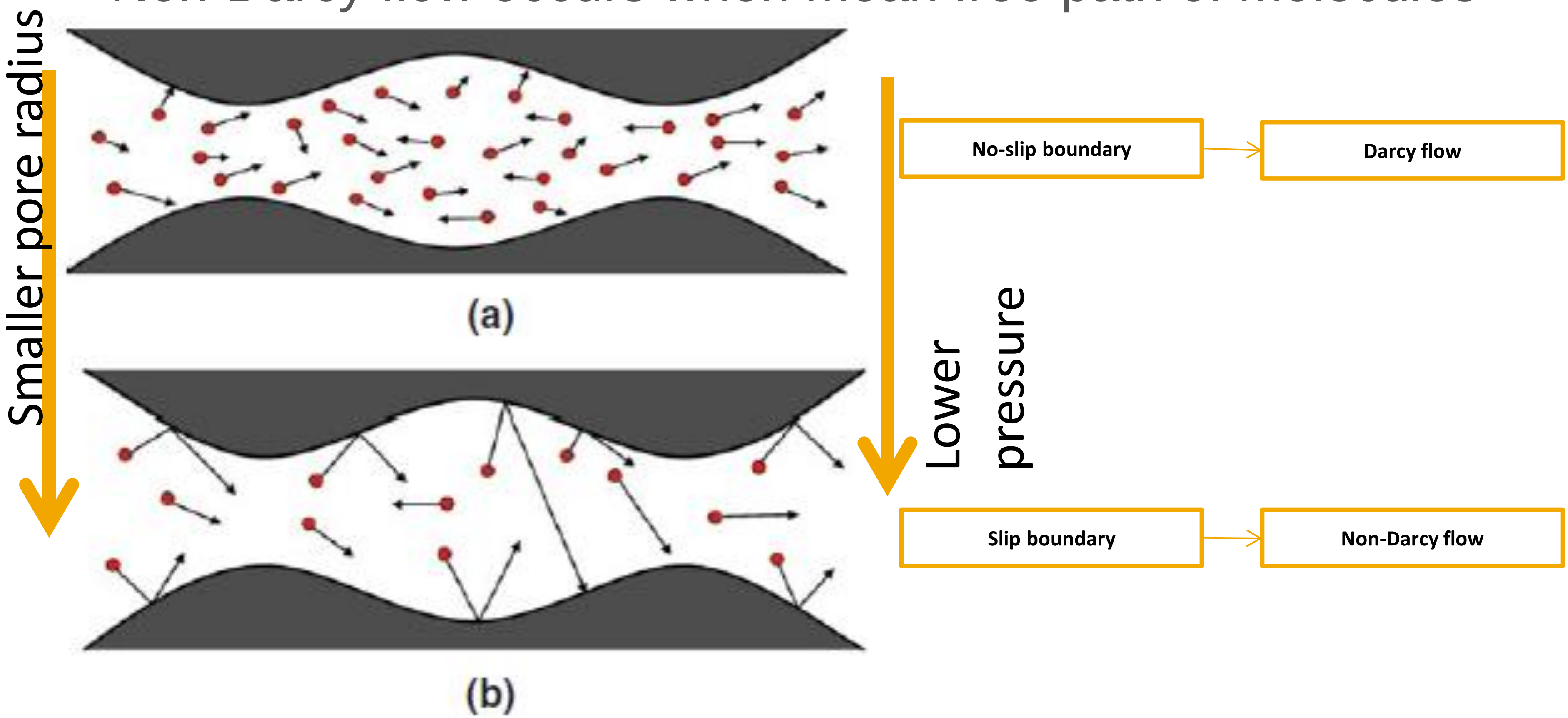


# two-phase envelope change
# Due to Pore proximity

| Group # | Component | % mole |
|---|---|---|
| 1 | CH4 | 80 |
| 2 | NC4 | 10 |
| 3 | FC8 | 10 |
| | Sum | 100 |



- Non-Darcy flow occurs when mean free path of molecules




Ziarani and Aguilera (2012)

# Introduction

- Knudsen number is a measure of degree of rarefaction

$$K_n = \frac{\lambda}{d}$$

- Smaller pores or lower pressure the higher the Kn
- The higher the Knudsen number the more deviation from Darcy flow

# Introduction

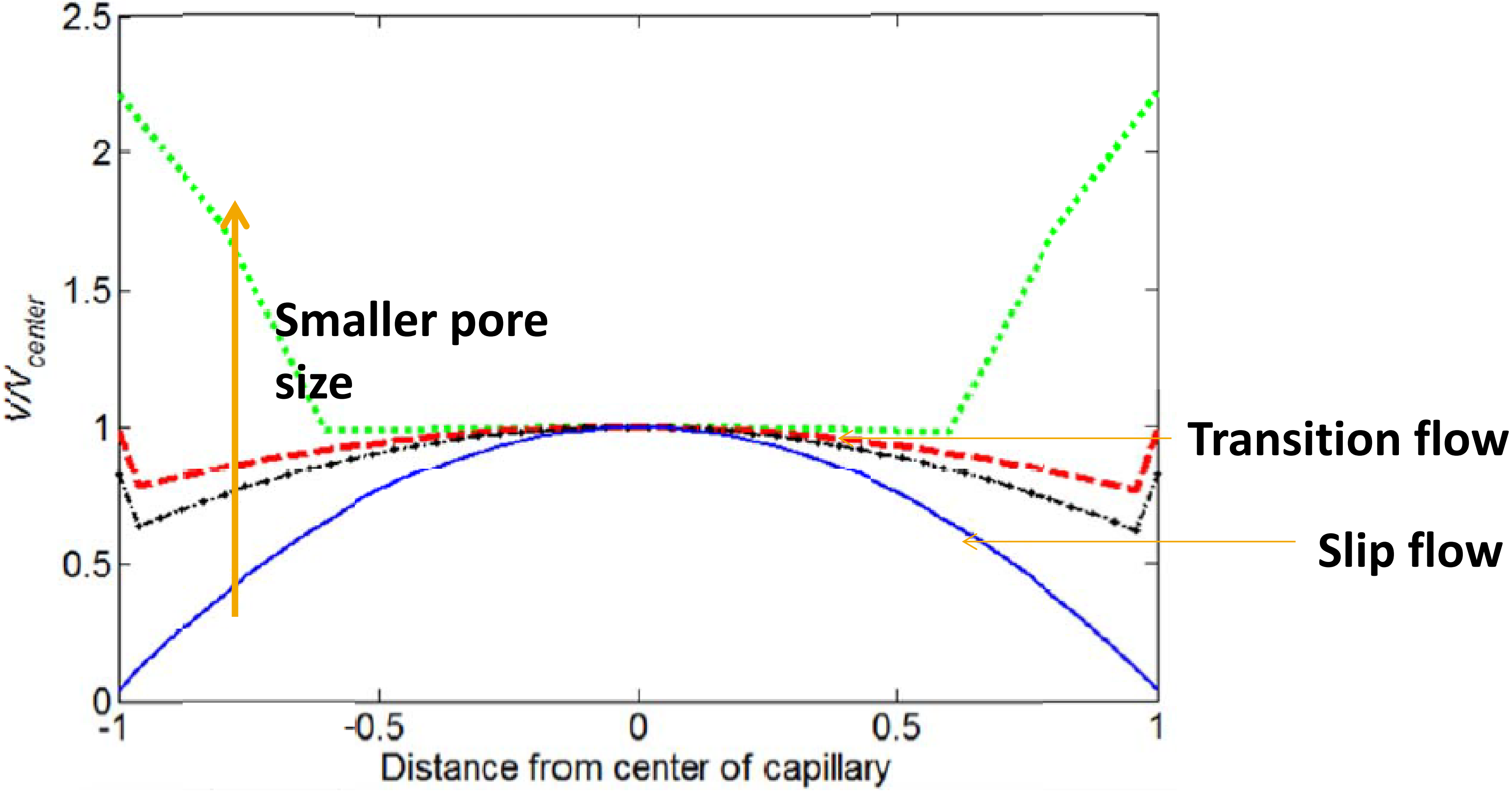
- Flow regimes

| Flow Equation | Flow Regimes | Knudsen Number Limits |
|---|---|---|
| Darcy | Continuum flow | Kn < 0.001 |
| Non-Darcy | Slip flow | 0.001 < Kn < 0. 1 |
| | Transition flow | 0.1 < Kn < 10 |
| | Free molecular flow | Kn ≥ 10 |

Schaaf and Chambre (1961)

**Tight and shale gas reservoir**

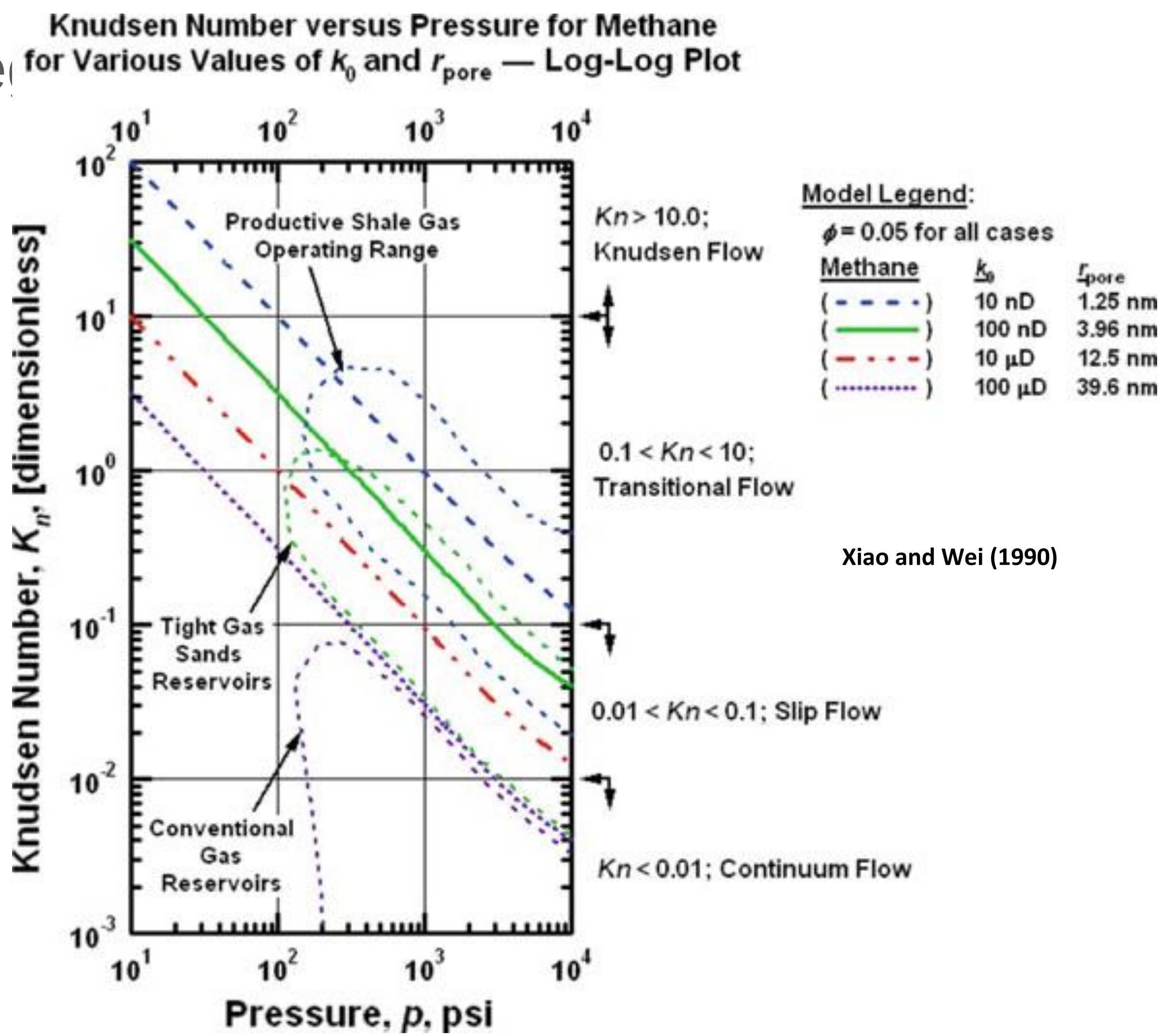
# Velocity profile in small capillaries




Fathi et al. (2012)

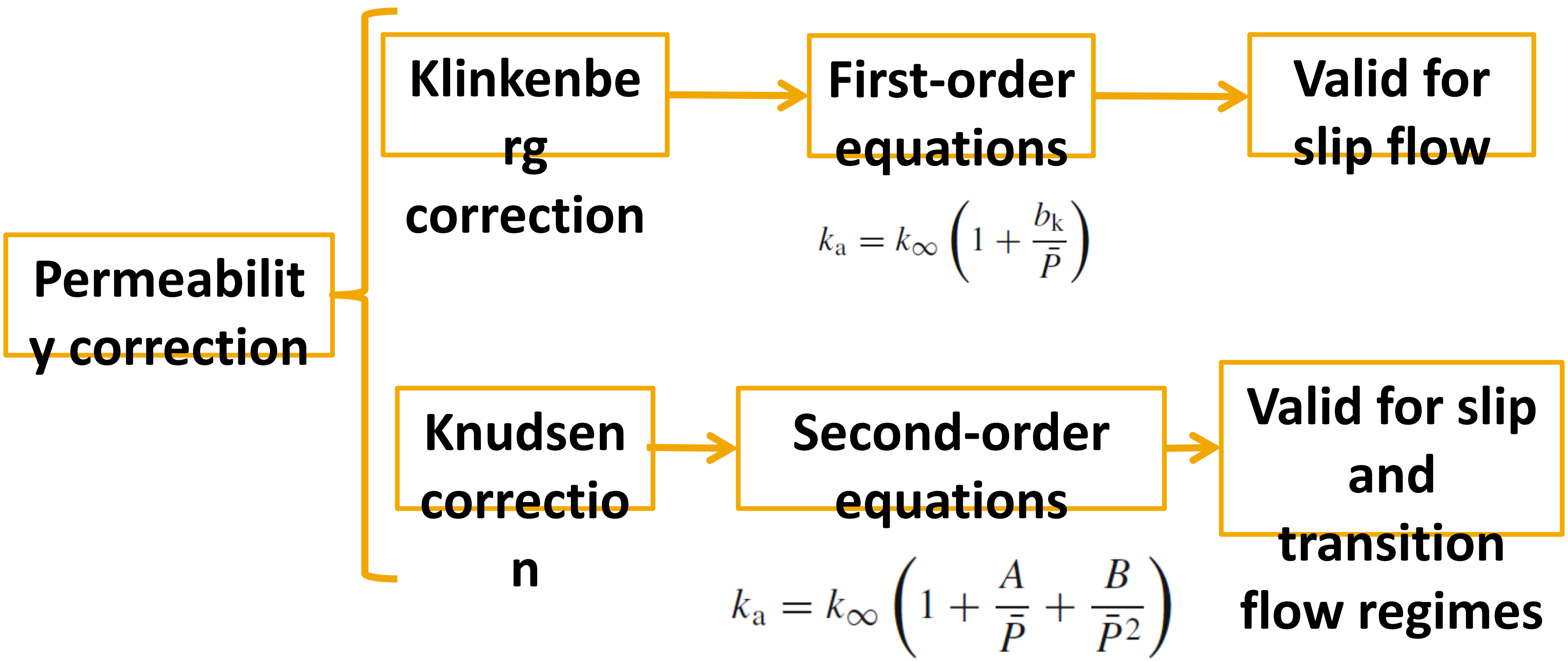
# Introduction

- Flow re




Xiao and Wei (1990)

# Permeability correction



# First-order equations (Klinkenberg correction)

- Klinkenberg (1941), first introduced the effect of gas slippage effect on Apparent permeability of gas

$$k_{\mathrm{a}} = k_{\infty}\left(1 + \frac{b_{\mathrm{k}}}{\bar{P}}\right)$$

- Slippage factor

$$\frac{b_{\mathrm{k}}}{\bar{P}} = \frac{4c\lambda}{r}$$

# First-order equations (Klinkenberg

Various correlations for Klinkenberg's gas slippage factor ($b_{\mathrm{k}}$)

| Model | Correlation | Comments/units | |
|---|---|---|---|
| Klinkenberg (1941) | $b_{\mathrm{k}} = 4c\lambda\,\bar{P}\,/r$ | $c$ is a constant close to unity | |
| Heid et al. (1950) | $b_{\mathrm{k}} = 11.419(k_{\infty})^{-0.39}$ | | |
| Jones and Owens (1979) | $b_{\mathrm{k}} = 12.639(k_{\infty})^{-0.33}$ | | |
| Sampath and Keighin (1982) | $b_{\mathrm{k}} = 13.851(k_{\infty}/\phi)^{-0.53}$ | | |
| Florence et al. (2007) | $b_{\mathrm{k}} = \beta\,(k_{\infty}/\phi)^{-0.5}$ | Gas | $\beta$-Value |
| | | Nitrogen | 43.345 |
| | | Air | 44.106 |
| Civan (2010) | $b_{\mathrm{k}} = 0.0094\,(k_{\infty}/\phi)^{-0.5}$ | Correlation for Nitrogen. Units: $b_{\mathrm{k}}$ (Pa), $k_{\infty}(m^2)$ | |

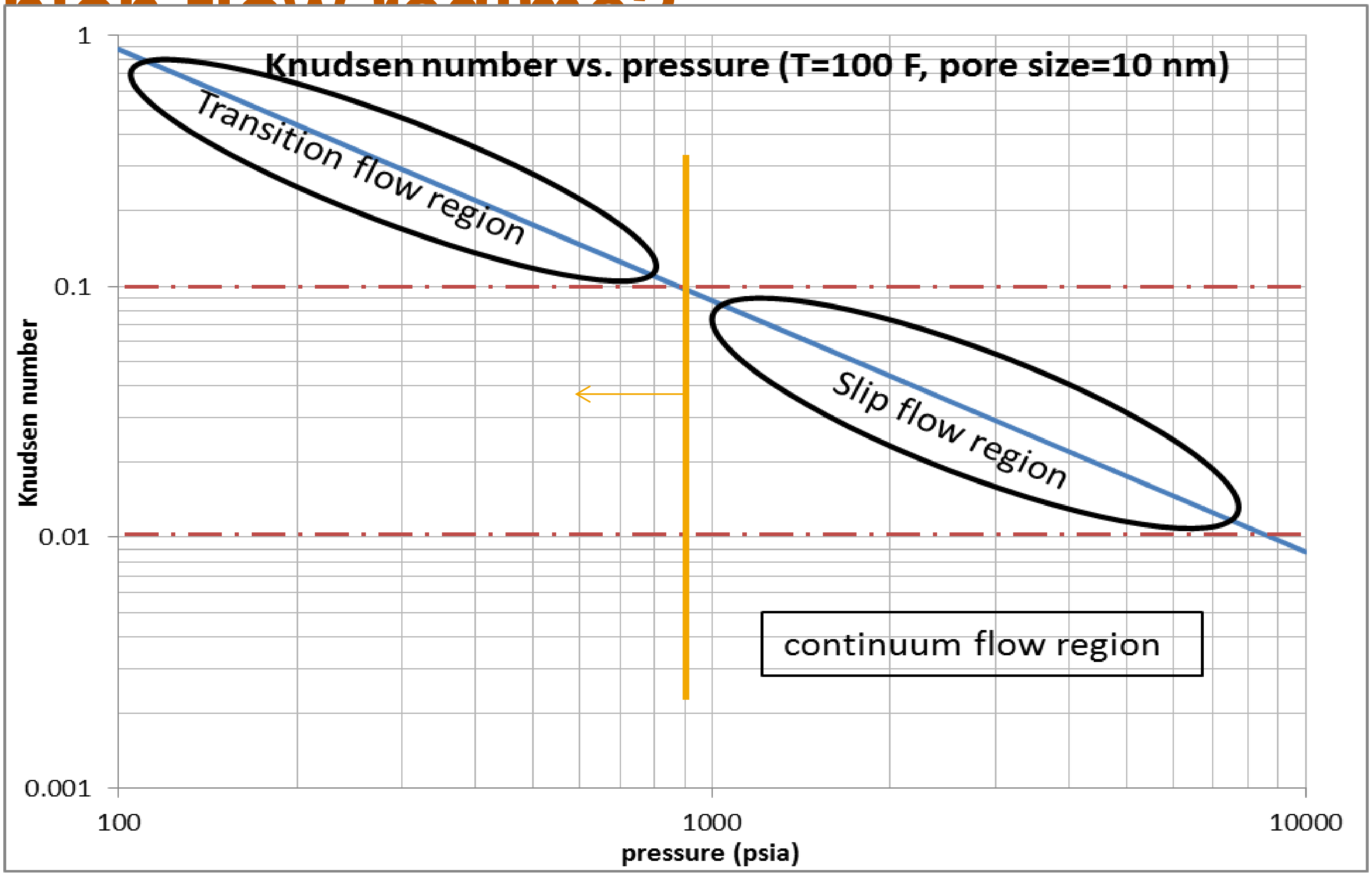
Units: $b_{\mathrm{k}}$ (psi), $k_{\infty}$ (md), $\bar{P}$ (psi), $r$ (nm), $\beta$ (psi), $\lambda$ (nm) and $\phi$ (fraction)

**Ziarani and Aguilera (2012)**

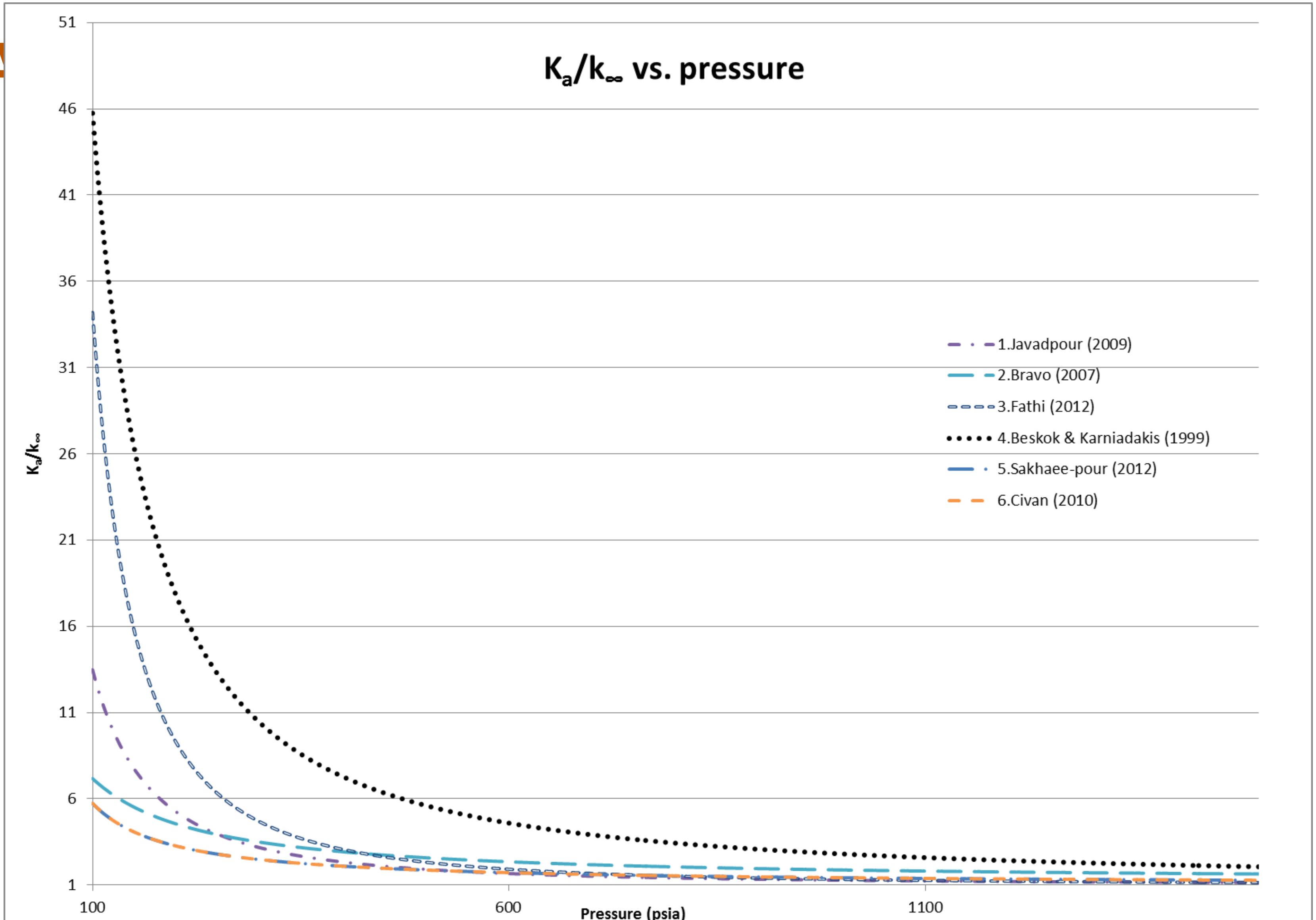
S

| Model | Correlation | Comments |
| --- | --- | --- |
| Beskok and Karniadakis (1999) | $k_a = k_\infty \left[1+\alpha(Kn)Kn\right]\left[1+\frac{4Kn}{1+Kn}\right]$ $\alpha(Kn) = \frac{128}{15\pi^2}\tan^{-1}\left[4Kn^{0.4}\right]$ | α is rarefaction coefficient and is a function of Knudsen number |
| Civan (2010) | $k_a = k_\infty \left[1+\alpha(Kn)Kn\right]\left[1+\frac{4Kn}{1+Kn}\right]$ $\alpha(Kn) = \frac{\alpha_0}{1+\frac{A}{Kn^B}}$ | Inverse power-law expression for rarefaction factor |
| Sakhaee-pour and Bryant (2012) | $k_a = k_\infty \left(0.8453+5.4576Kn+0.1633Kn^2\right)$ | 0.1<Kn<0.8 |
| Javadpour (2009) | $k_a = \frac{D_k \mu M}{RT\rho} + Fk_\infty$ $F = 1+\left(\frac{8\pi RT}{M}\right)^{0.5}\frac{\mu}{\overline{\mathrm{P}}r}\left(\frac{2}{\alpha}-1\right)$ | |
| Fathi (2012) | $k_a = k_\infty \left[1+\left(\frac{b}{\overline{P}}\right)^2\left(\frac{L_{KE}}{\lambda}\right)\right]$ | Double-slip theory |
| Bravo (2007) | $b = f(P)$ | Three velocity profiles |

# Which flow regime?



A


$K_a/k_\infty$ vs. pressure
51
46
41
36
31
26
21
16
11
6
1
$K_a/k_\infty$
100
600
1100
Pressure (psia)
1.Javadpour (2009)
2.Bravo (2007)
3.Fathi (2012)
4.Beskok & Karniadakis (1999)
5.Sakhaee-pour (2012)
6.Civan (2010)

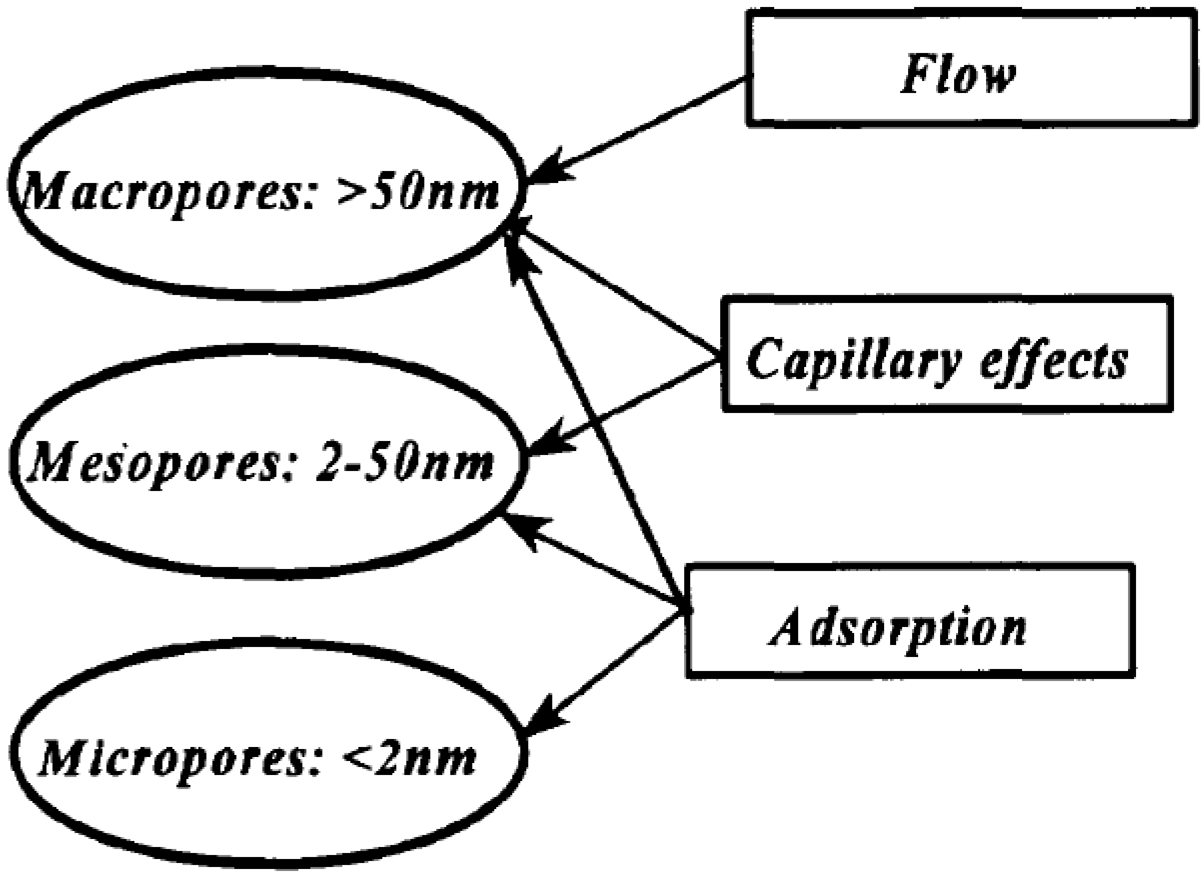
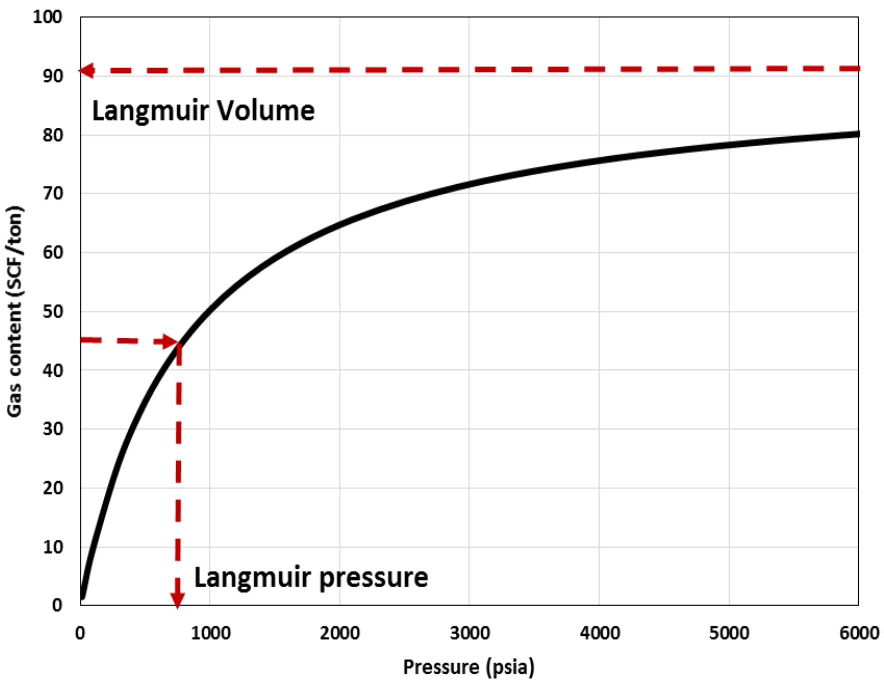



Fig. 1 - Pore size scales for different effects occurring in natural reservoirs.

# Adsorption model

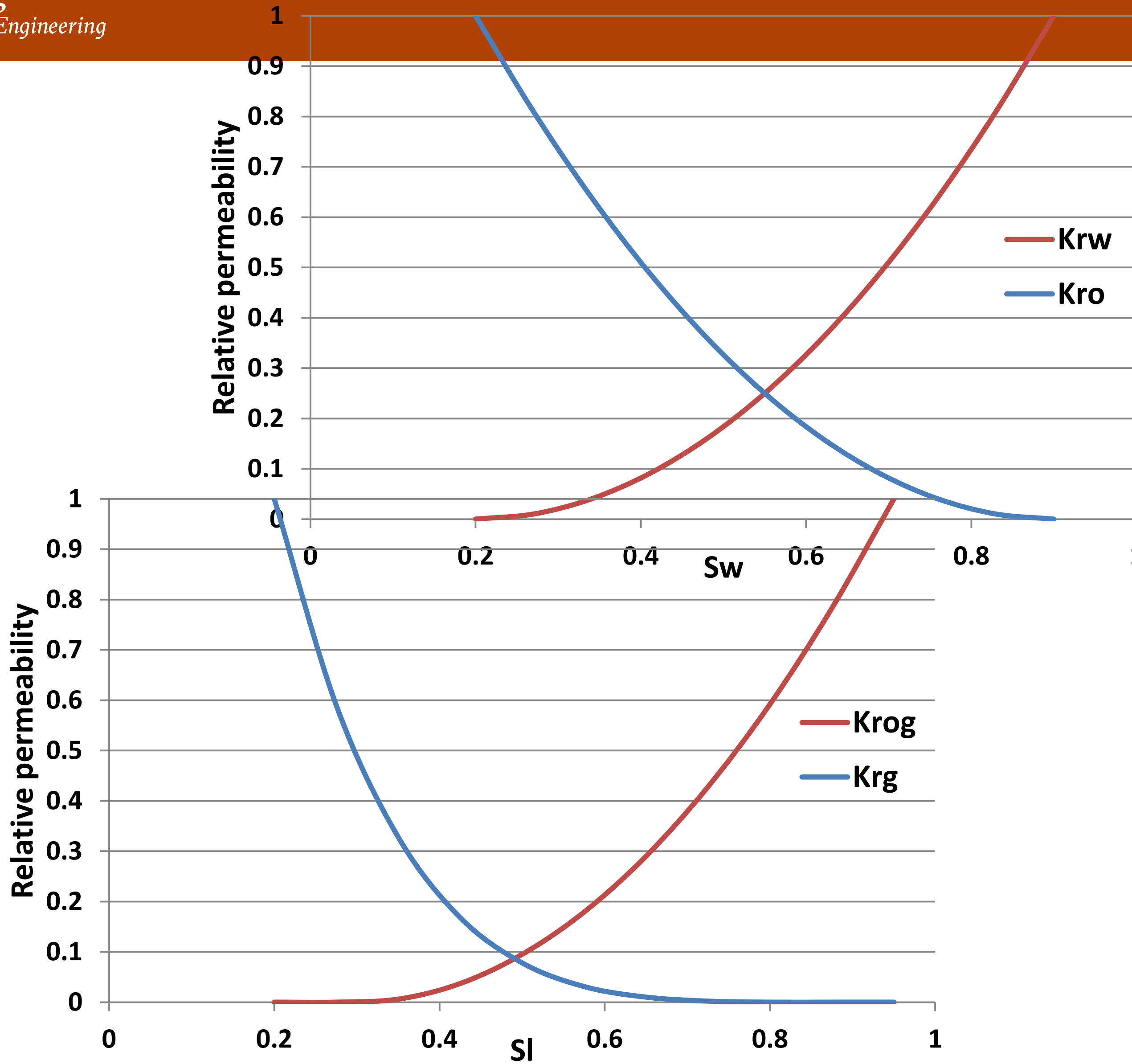
- Extended Langmuir (EL) model



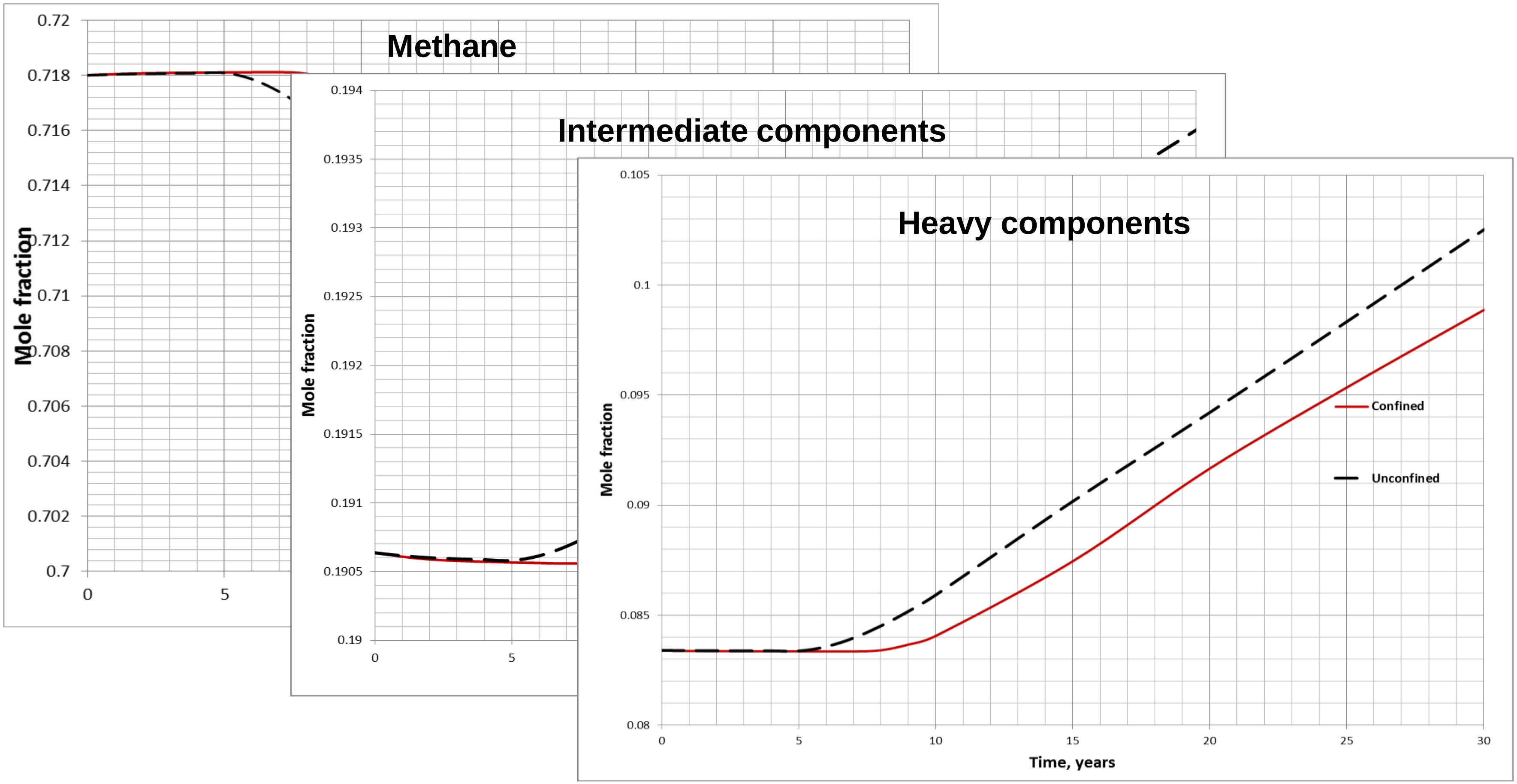

Langmuir Isotherm curve

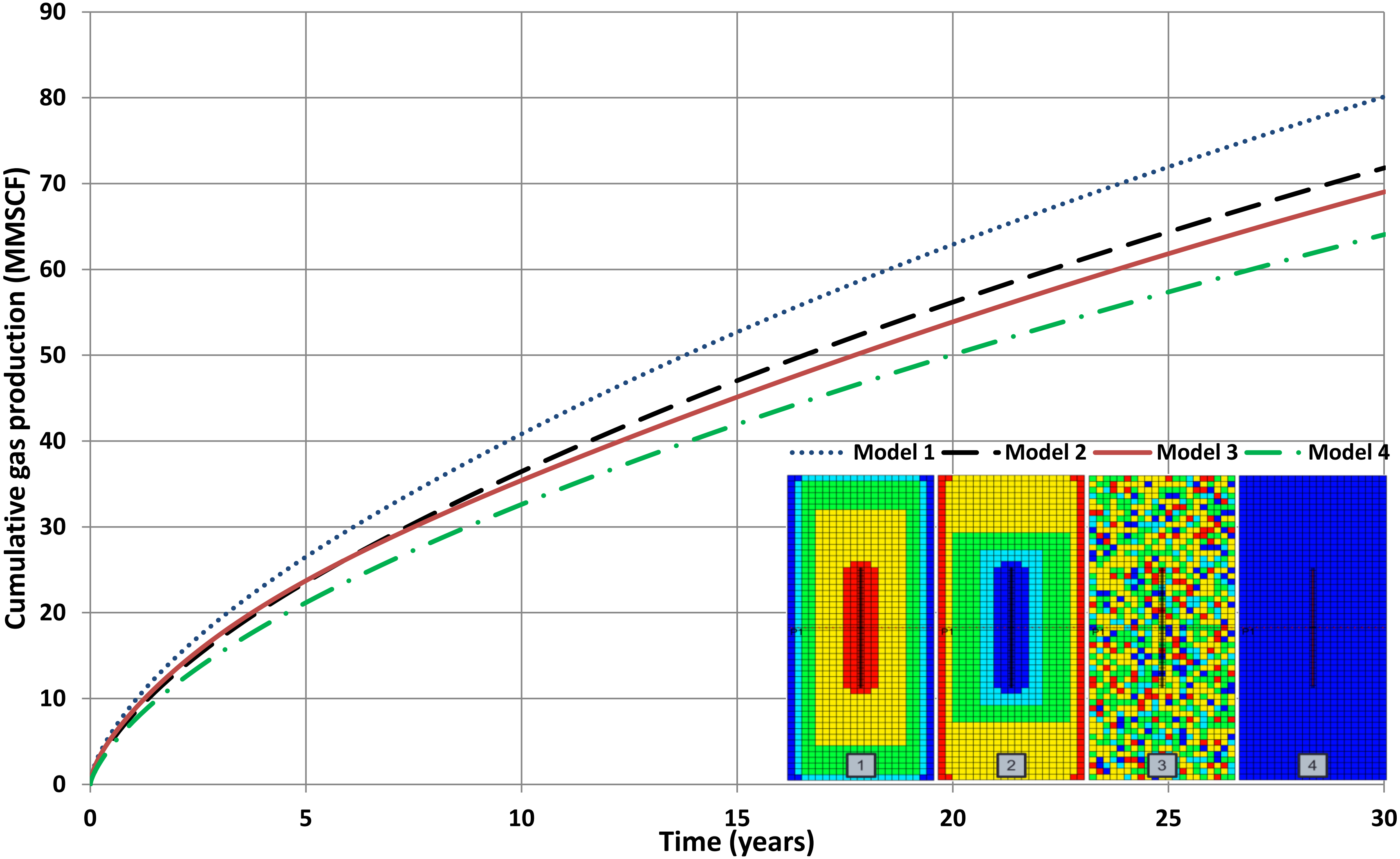
$$G = \frac{V_L P}{P + P_L}$$

$$G_{Li} = \frac{V_{L,i}(P_i/P_{Li})}{1 + \sum_j (P_j/P_{Lj})}$$


Relative permeability
Sw
Krw
Kro
Relative permeability
Sl
Krog
Krg
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

# Effect of confinement on components mole fraction




Cumulative gas production (MMSCF)
0
10
20
30
40
50
60
70
80
90
0
5
10
15
20
25
30
Time (years)
Model 1
Model 2
Model 3
Model 4
1
2
3
4

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