Are Gas Shales Suitable Analogs for Oil Shale Exploration?*

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Search and Discovery Article #41624 (2015)**
Posted June 22, 2015

*Adapted from oral presentation given at AAPG 2015 Southwest Section Annual Convention, Wichita Falls, Texas, April 11-14, 2015

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Abstract

Gas shales are not suitable direct exploration analogs for oil resource plays. First, reservoirs with properties sufficient for gas production may be insufficient for oil production. Second, oil in resource plays may have migrated from their source beds, whereas gases in mudrock reservoirs are usually self-sourced. Finally, gas sorbed in reservoirs can contribute to production whereas oil sorbed in the reservoir cannot be desorbed.

Subsurface oil viscosity is about 100 times higher than gas viscosity. Oil reservoirs therefore need about 100 times higher permeability to produce at equivalent subsurface volumetric rates. Oil reservoirs have less drive. The oil reservoir must have higher permeability to compensate for the lower drive. Oil drive increases with higher initial pressure and dissolved gas content. Fractures may compensate for lower matrix permeability, but they will not compensate for lower drive and the displacement nature of oil production.

Gas migration into nanoDarcy reservoirs is difficult or impossible. Gas-charged nanoDarcy reservoirs must be self-sourced. The gas-productive fairway can be predicted from the thermal maturity and source rock quality. In contrast, oil can migrate into reservoirs with microDarcy permeability; self-sourcing is not needed. Oil can accumulate in thermally immature, low permeability reservoirs, depending in part on migration and sealing patterns. Oil sorbs so tightly to organic matter that sorbed oil cannot be produced by any primary production mechanism. Organic matter increases reservoir sorption, so high organic content may reduce the oil recovery efficiency from a tight oil reservoir. Characteristics favorable for oil resource plays are the following:

- Permeability should exceed a microDarcy or so, and oil saturation should be high to give a high oil relative permeability. Oil saturation needs to be corrected for the oil sorbed on kerogen so that calculated saturation is that of the volumetrically stored oil.
- In situ GOR and pressure need to be relatively high. This requires suitable oil thermal maturity and relatively deep reservoirs.
- Reservoirs need to be in a position favorable for charging from a thermally mature oil source rock. The reservoir itself can be thermally immature.

ARE GAS SHALES SUITABLE ANALOGS FOR OIL SHALE EXPLORATION?

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Objectives

- Show why gas shale accumulations cannot be used as analogs for oil exploration.
- Effects examined here:

Sorption

Mobility

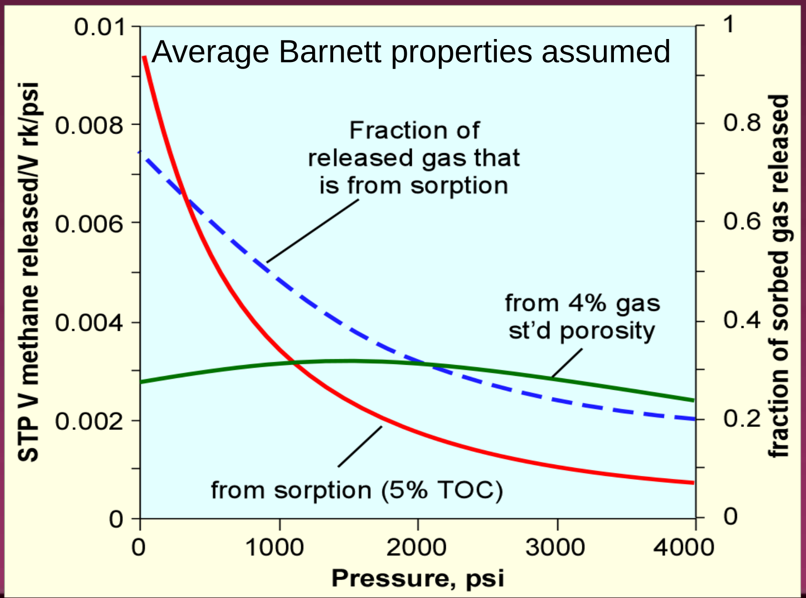
Drive

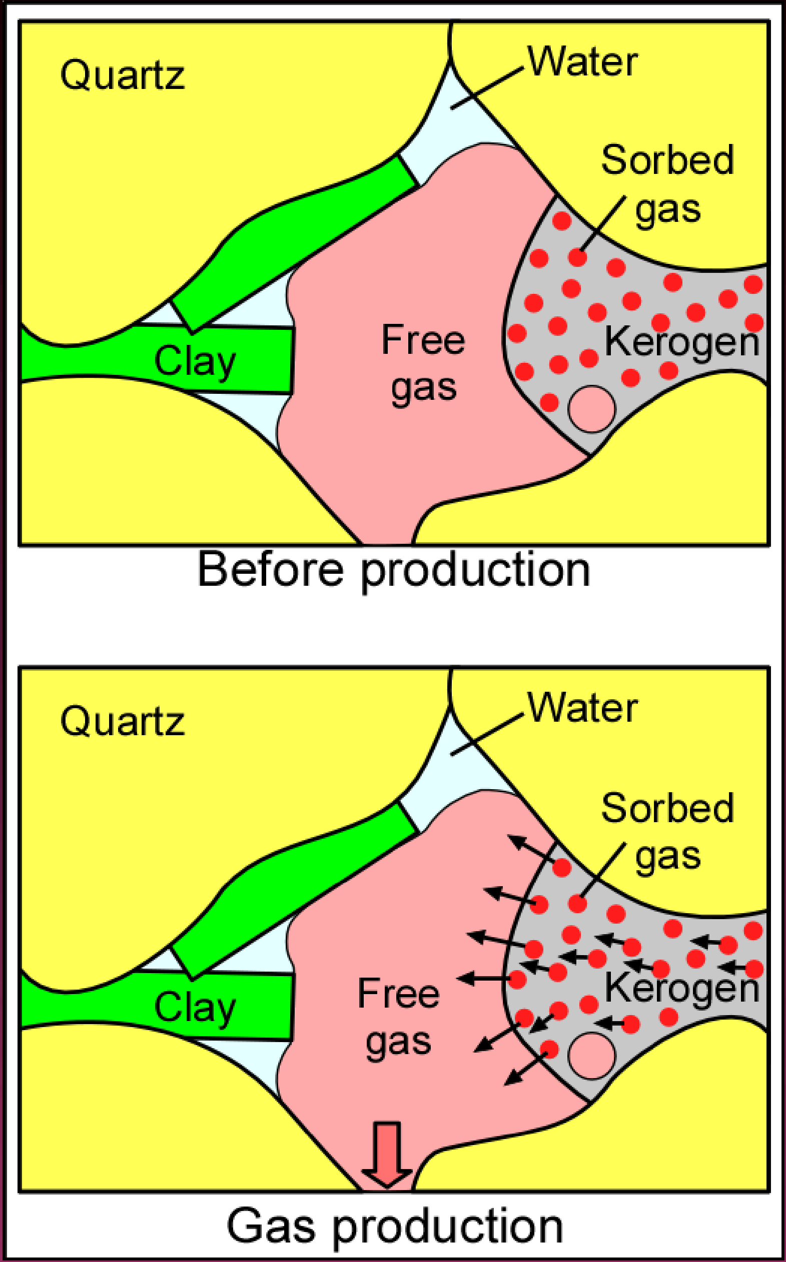
Capillarity

Sorption

Sorption in Shale Gas

- At reservoir pressure, gas sorbs into kerogen, adding to total gas storage (upper).
- As gas is produced and pressure drops, gas desorbs from the kerogen and adds to the total gas production (lower left).
- About 20% of initial production in Barnett type reservoir is desorbed gas. Percent desorbed gas increases as pressure drops.



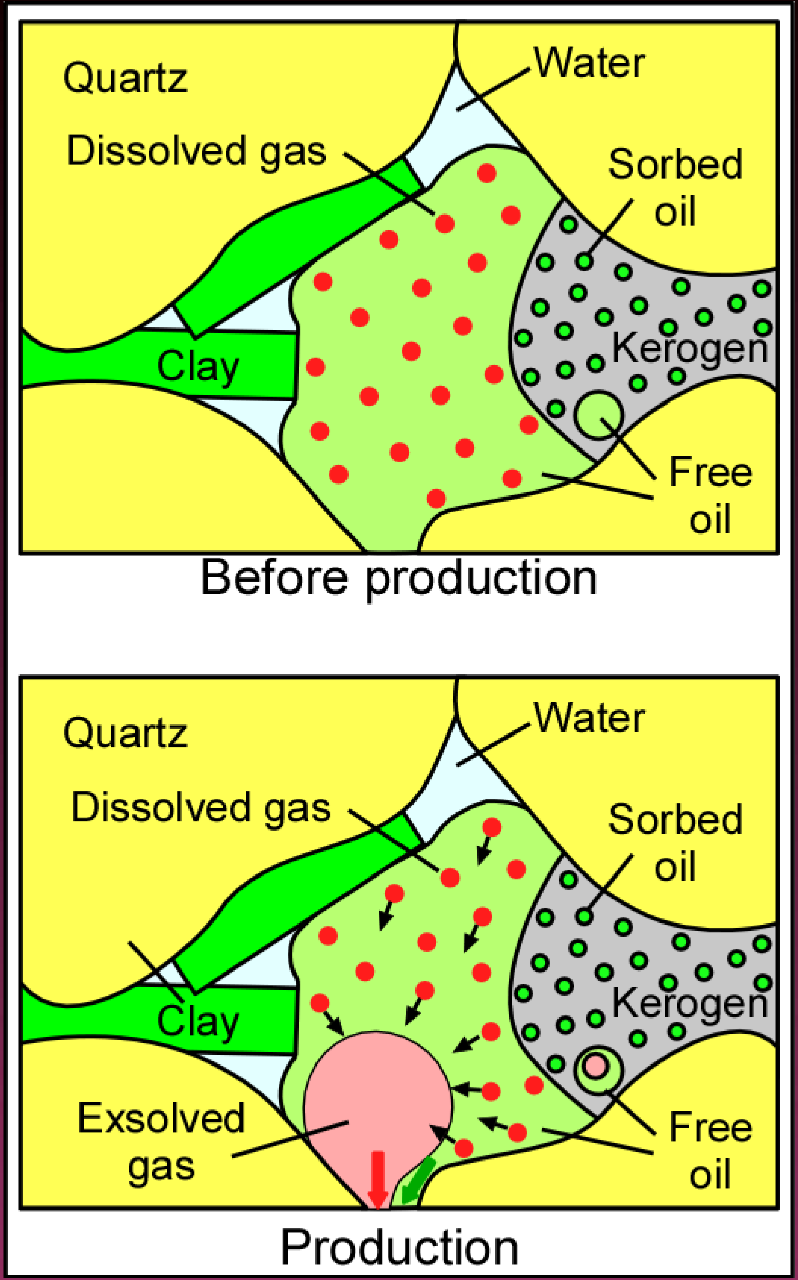


Oil Does Not Produce From Sorption Reservoirs

- Oil sorbs onto kerogen (~100 mg oil/g TOC) more than light hydrocarbons and methane (~15 mg gas/g TOC).
- Oil components selectively displace methane from sorption due to their lower boiling point.
- Oil does not desorb. Reservoir temperatures are less than boiling points of sorbed oil components. Organic matter does not add to recoverable storage.

Sorption in Oil Shale

- Oil is sorbed into kerogen and gas is dissolved in oil (upper figure).
- Gas exsolves from oil as pressure drops, but sorbed oil is not desorbed (lower figure).
- Sorbed oil remains in kerogen and does not add to production.



Mobility

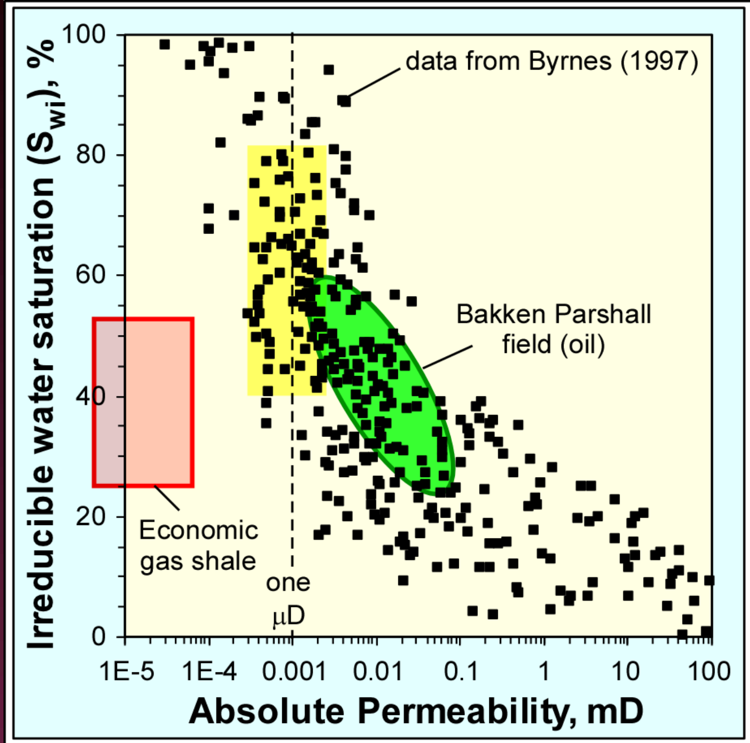
$$q = k/\mu \; \Delta P/\Delta L$$

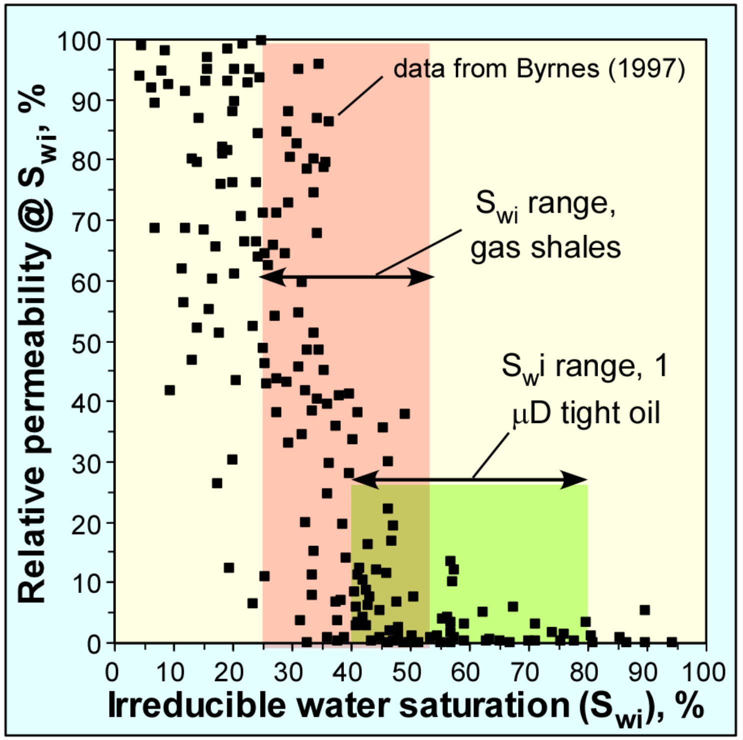
(mobility = permeability/viscosity)

Oil Reservoirs Require Higher Permeability for Equal Flow Rates

- Subsurface oil viscosity is from 30 to 100+ times higher than gas viscosity.
- Oil is 30 to 100+ times less mobile than gas in the same permeability rock.
- An oil reservoir must be 30 to 100+ times more permeable than a gas reservoir to produce at the same rate.
  - For example, an oil reservoir with 1 cp oil viscosity must have a 500 nD (0.5 μD) oil permeability to have the same mobility as a reservoir with 10 nD gas permeability and 0.02 cp gas viscosity.

Permeability and Saturation: Tight Oil





- Endpoint relative HC permeability decreases as absolute permeability decreases in water-wet reservoirs. Tight oil reservoirs fall along the water-wet tight S_{wi}-permeability trend. Shale gas reservoirs have low Sw, even at low permeability.
- Oil-phase permeability in tight (<1 μD), water-wet oil reservoirs will be substantially less (<10%) than absolute permeability due to their high water saturation.

HC Mobility: Tight Oil vs. Tight Gas

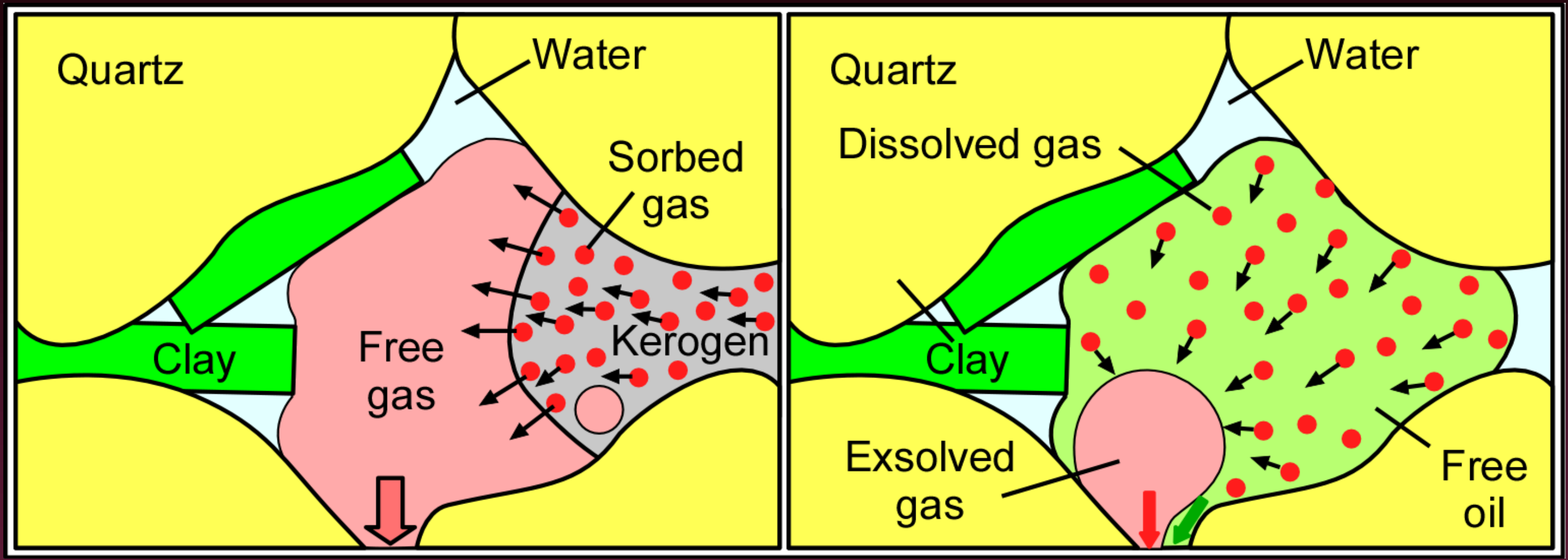
- **Viscosity effect**: Oil-phase permeability must be a factor of 30 – 500 times higher than gas-phase permeability to have same flow rate.
- **Relative permeability effect**: Absolute permeability of water-wet oil reservoirs must be greater than about 1 microDarcy to have sufficiently low S_{wi} for high oil relative permeability.
- **Conclusion**: Tight oil reservoirs need a minimum absolute permeability near 1 microDarcy for economic flow potential. Higher is better. This excludes true mudstones.

Tight sand data from Byrnes, 1997

Production Drive

(Type and energy)

Production Drive



<u>**Gas Expansion (gas shale)**</u>

- Constant saturation; no change in K_r
- High drive energy due to high gas compressibility
- High recovery efficiency (~70%+)

<u>**Solution Gas (tight oil)**</u>

- Oil permeability decreases as gas saturation increases with production.
- Less energy (more rapid pressure drop with production).
- Increasing GOR with production.
- Low recovery efficiency (~20%).

Capillary Effects

Charge scenario

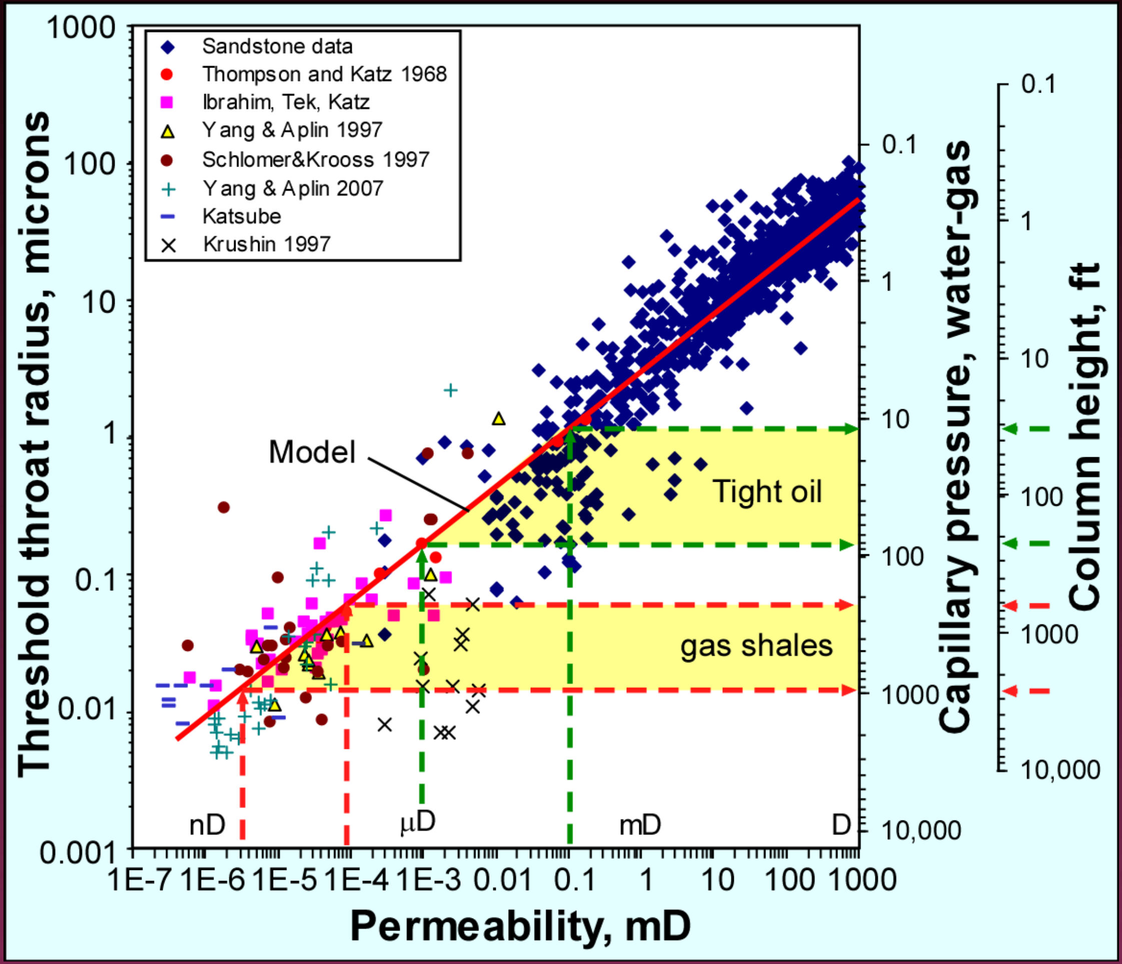
Water cut

Accumulation Charge

- **<u>Self sourced</u>**: Petroleum is generated from the reservoir rock itself.
  - –Reservoir fairways are constrained by thermal maturity
  - –Reservoir must have source-rock characteristics (high TOC, favorable kerogen type, etc.).
  - –Characteristic of shale gas.
- **<u>Charged</u>**: Petroleum is generated in a source rock outside the reservoir and migrates into the reservoir.
  - –Reservoir must have pore network properties favorable for petroleum charge.
  - –Reservoir must be located in a position where it can be charged from thermally mature source rock.

Capillary Pressure and Permeability

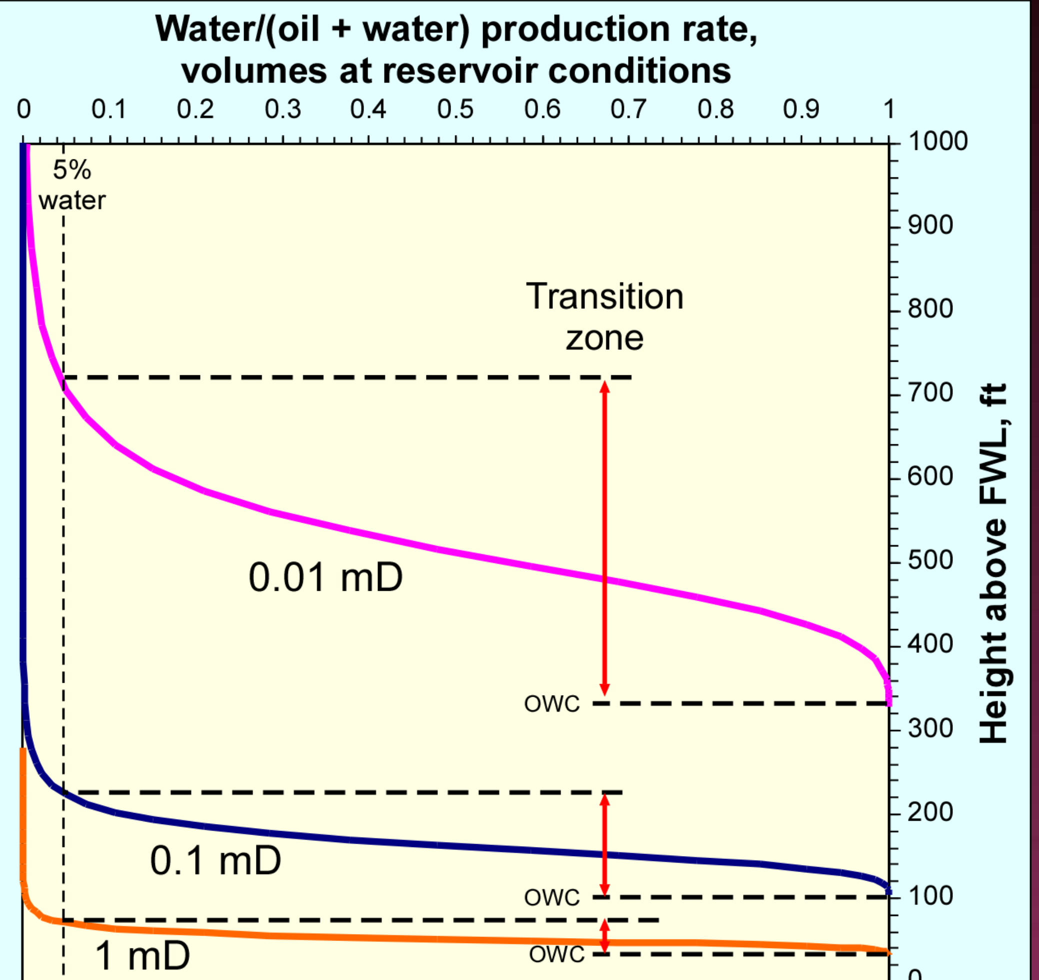
- Low permeability gas shales require such high capillary pressure that they can only be self sourced.
- Higher permeabilities of tight oil require lower capillary pressures, so charge or self source is possible in water-wet tight oil reservoirs.



Assumes 0.2 g/cc gas, 50 mN/m² surface tension, and strongly water-wet reservoir for gas and Assumes 0.7 g/cc oil, 20 mN/m2 surface tension, 30o wettability angle for oil.

Water Production in Tight Oil Reservoirs

- Water is co-produced with oil in the transition zone.
- Transition zone thickness increases as permeability decreases. Most water-wet tight oil reservoirs are in the transition zone.
- Tight zones in interbedded reservoirs produce water while permeable beds produce oil.
- Initial water cut increases as average reservoir permeability decreases and heterogeneity increases.



10% porosity, water-wet oil reservoir; Brooks-Corey rel perm correlations; lambda = 1.5

Implications of Capillarity

- Charge:
  - Gas shales must be self sourced, so they must have high TOC and suitable thermal maturity for gas production.
  - Tight oil may be self sourced or migrated. If migrated, high TOC is not necessary and reservoirs may be thermally immature.
- Water cut:
  - Initial water cut increases as permeability of the tight oil reservoir decreases.
  - Tight reservoir heterogeneity increases water cut. Tight beds will produce water even if partially oil saturated, whereas more permeable beds produce oil with lower water cut.
  - Massive fracture stimulation reduces potential for reduce water cut by selective zone completion.

What Do We Look For (Shale-Associated Oil Production)?

- Higher absolute permeability than in gas shales (~1 microDarcy minimum and preferably much higher). NanoDarcy-scale mudstone permeabilities are too low for economic oil production rates.
- High TOC is <u>not</u> necessary for an economic tight oil reservoir.
- Reservoir can be thermally immature if in a location for favorable migration and charge.
- Low water saturation. (higher oil relative permeability and lower water cut).
- High initial GOR. (increases drive energy and recovery).

Fracture Stimulation?

- Gas shales work because we can increase effective permeability by increasing fracture permeability.
- Fracture stimulation of tight oil reservoirs has its limits:
  - Fracture number (or surface area) in stimulated volume would have to increase by factors of 10 to 100 to offset the mobility reduction by higher oil viscosity.
  - Fracturing will not be able to offset the lower drive of tight oil reservoirs.
  - Water may be produced from the water saturation in partially saturated tight oil reservoirs. Fracturing may increase watercut if the reservoir is heterogeneous and a large fraction of tight rock is stimulated along with more permeable rock.

Conclusions

- Basic rock properties constrain where oil can be economically produced from tight, shale-associated reservoirs.
- Economic gas shale production does not imply that the same rock type could produce oil economically if hydrofractured more.
- Properties used to guide exploration and evaluation of gas shales do not necessarily apply to oil exploration.
- Tight oil reservoirs:
  - need higher minimum permeability than gas shales.
  - Can be thermally immature because charge by migrating oil is possible whereas gas shales must be self sourced.
  - have high initial water cuts that increase with decreasing permeability and increasing reservoir heterogeneity.
  - have low recovery factor due to drive type.