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EPA HF Workshop

Flow of Gas and Water in Hydraulically Fractured Shale Gas Reservoirs

RANGE RESOURCES

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Outline

- Controlling factors for fluid flow
- Permeability of Marcellus shale
- Hydraulic fracturing
- Pressure sinks and pressure distribution
- Fate of frac water
- Concluding remarks

Controlling Factors for Fluid Flow

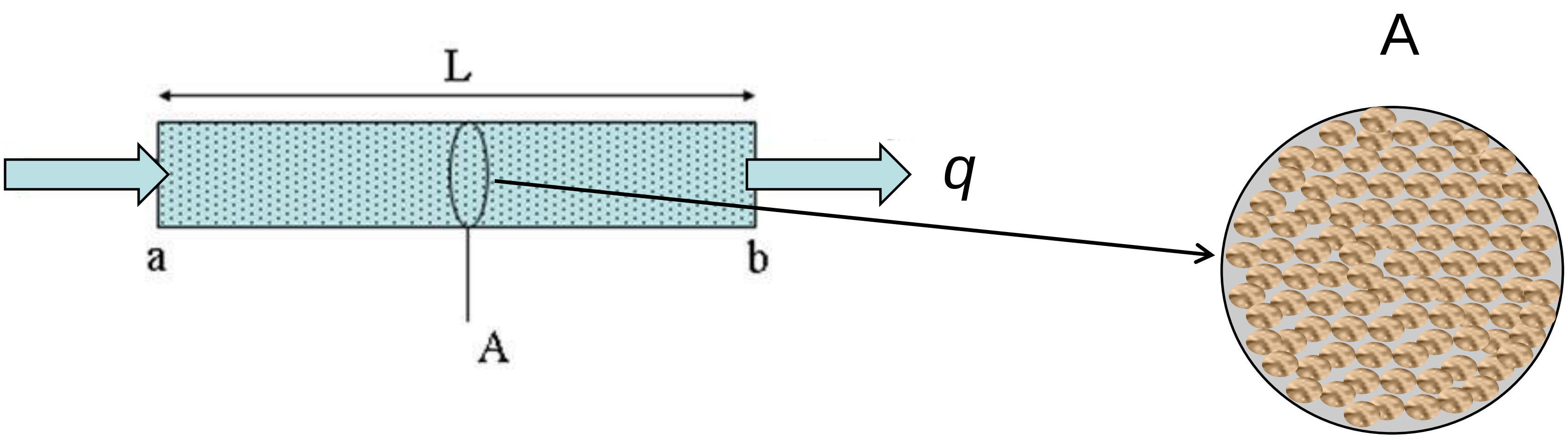
- Hydraulic conduit and pressure gradient

Permeability – a measure of flow capacity

Darcy's Law

$$q = \frac{k}{\mu} A \frac{p_a - p_b}{L}$$

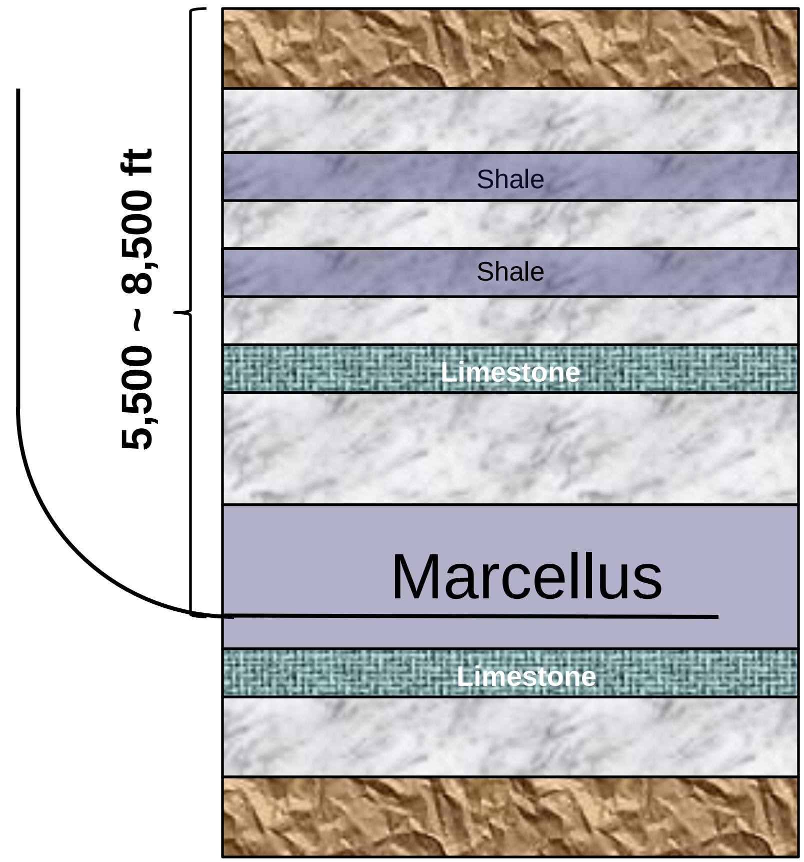
Pressure gradient, ∇p , psi/ft



Permeability of Marcellus Shale

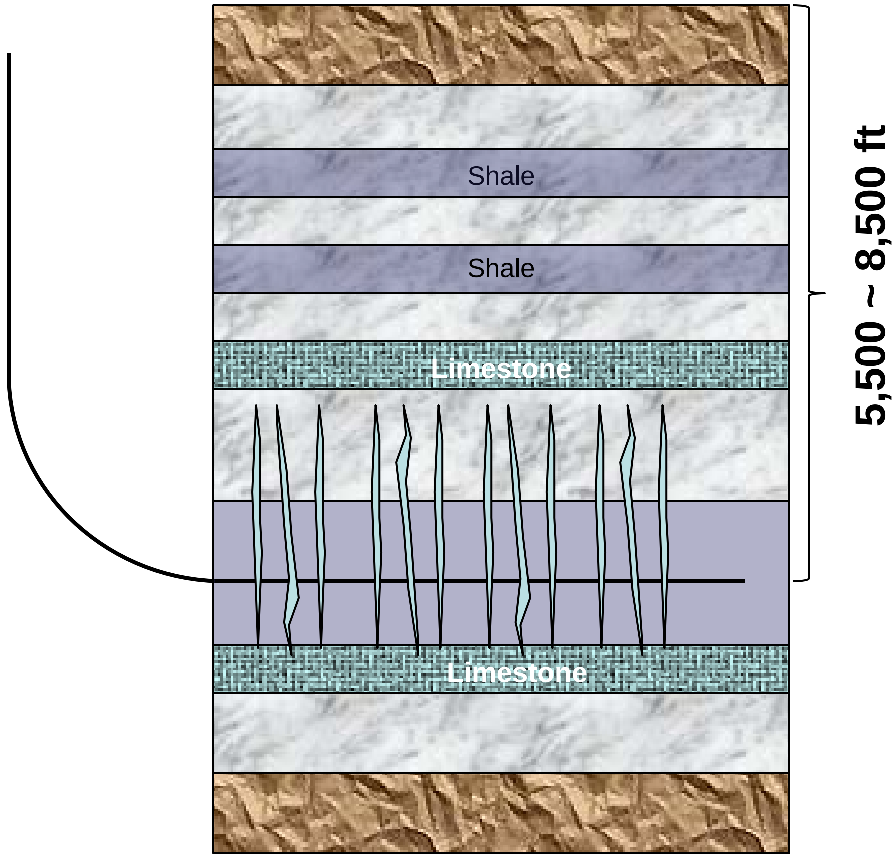
Marcellus Shale	
Depth, ft	5,500 ~ 8,500
Matrix Porosity (%)	2 ~ 12
Matrix Permeability (nanodarcy)	100 ~ 450
Pore Size (nanometer)	10s ~ 100s

$k_v << k_h \quad k_v = \pm 0.01 \times k_h$

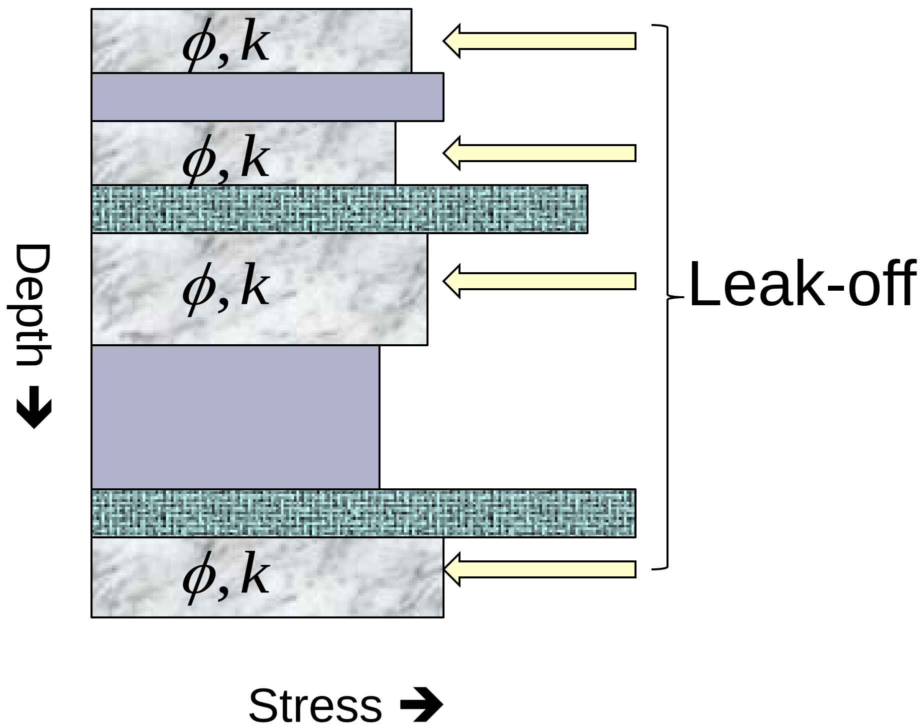


Shale typically serves as a cap rock to prevent escape of fluids

Hydraulic Fracturing

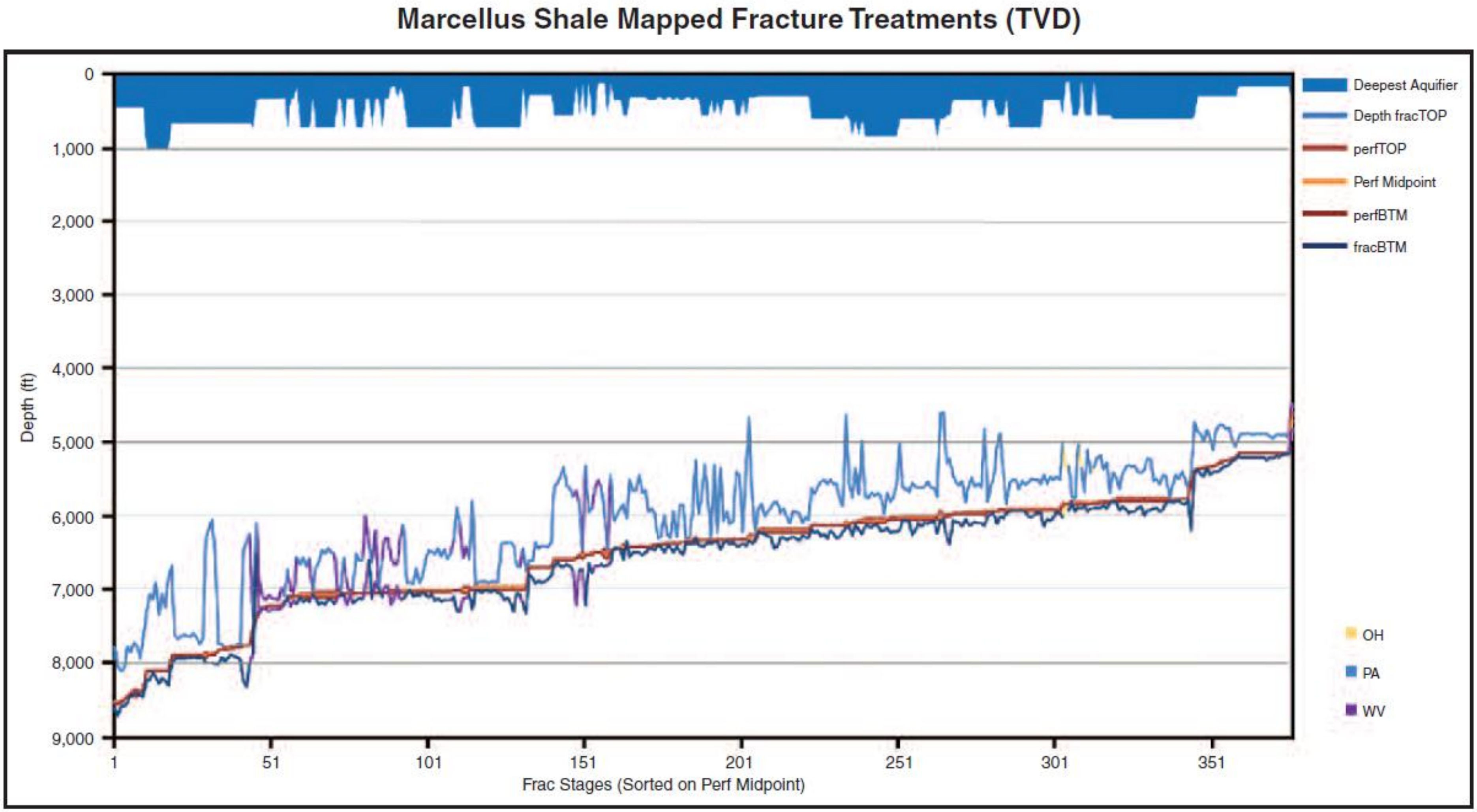


Stress Profiles



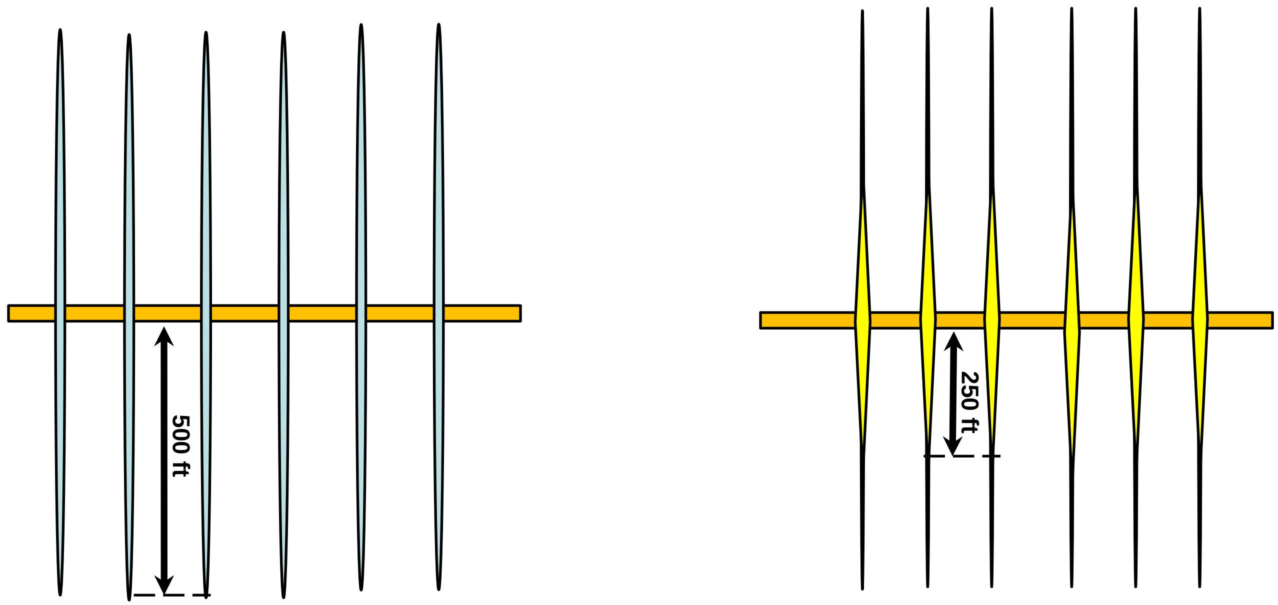
Fracture height growth is confined by stress barriers and formation leak-off etc.

Microseismic Data from Marcellus Shale Treatments



Fracturing of the Marcellus cannot impact groundwater

Areal View

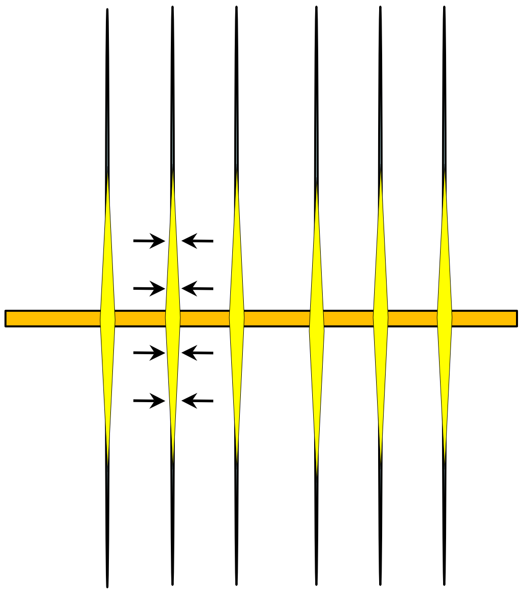


Created Fracture Length > Propped Fracture Length

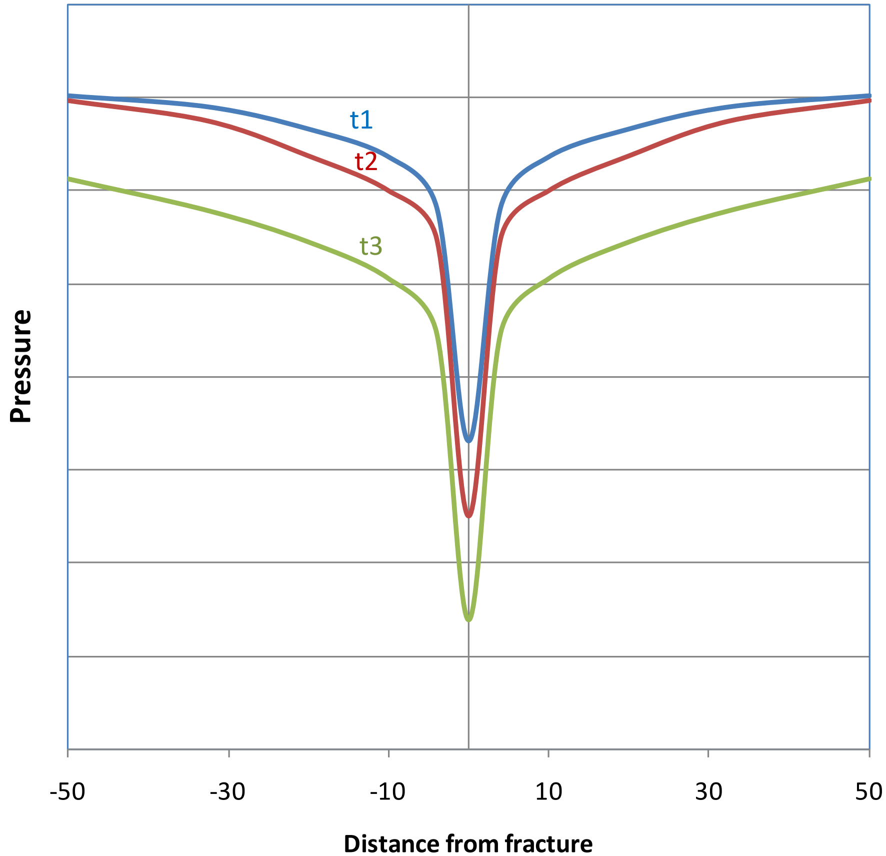
During treatment   After treatment

Some of induced fractures may become isolated after treatment

Pressure Sinks During Production

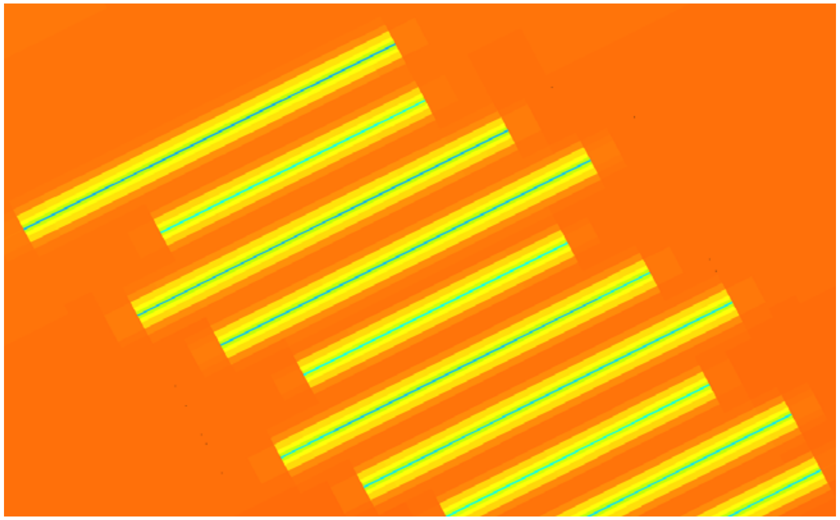


Gas flow ⟹ fractures ⟹ wellbore

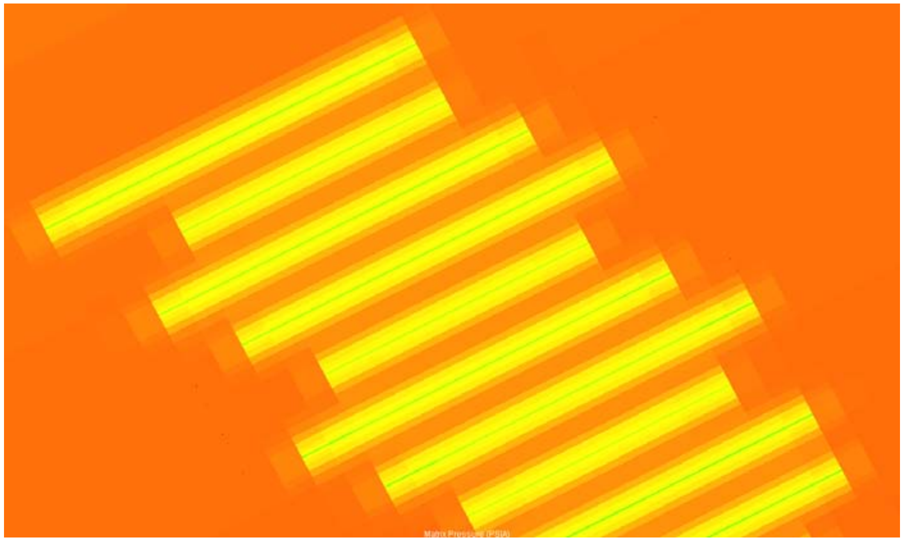


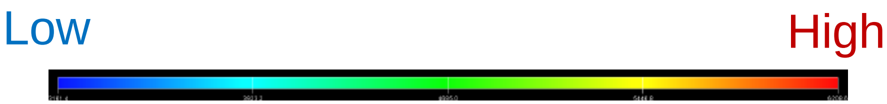
Pressure Distributions

During Production



During Shut-in

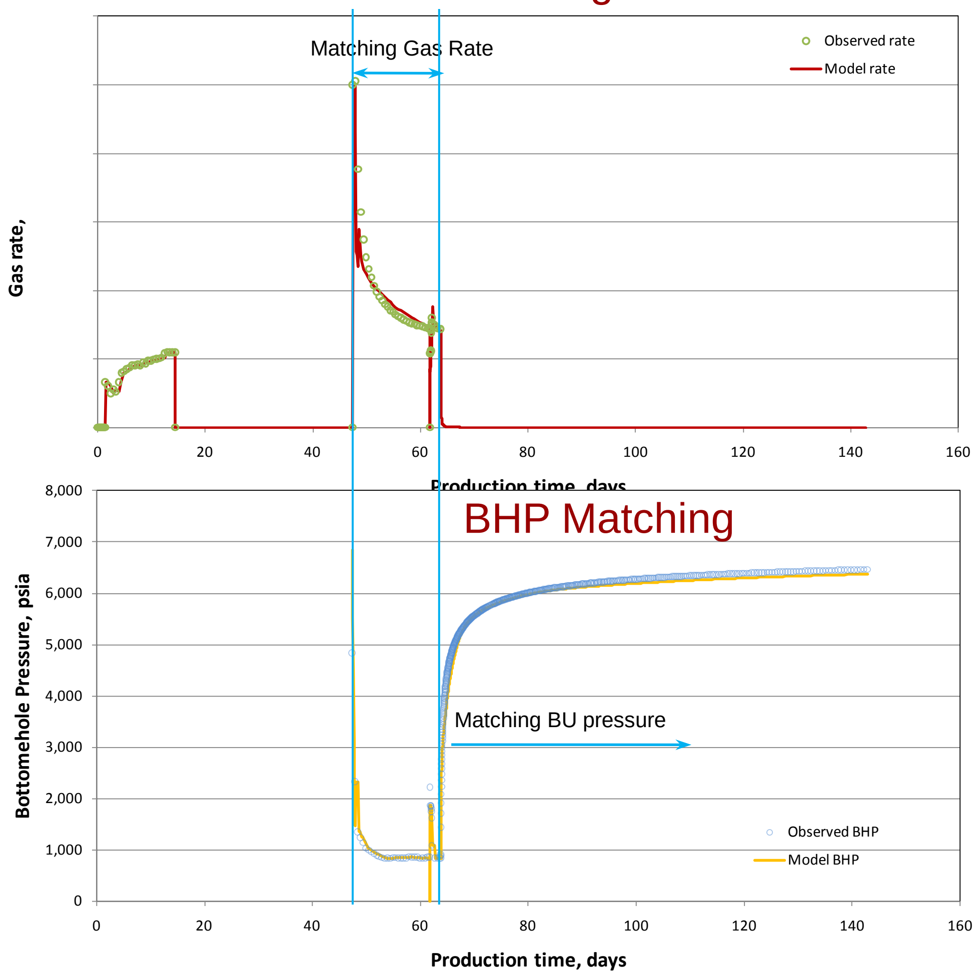


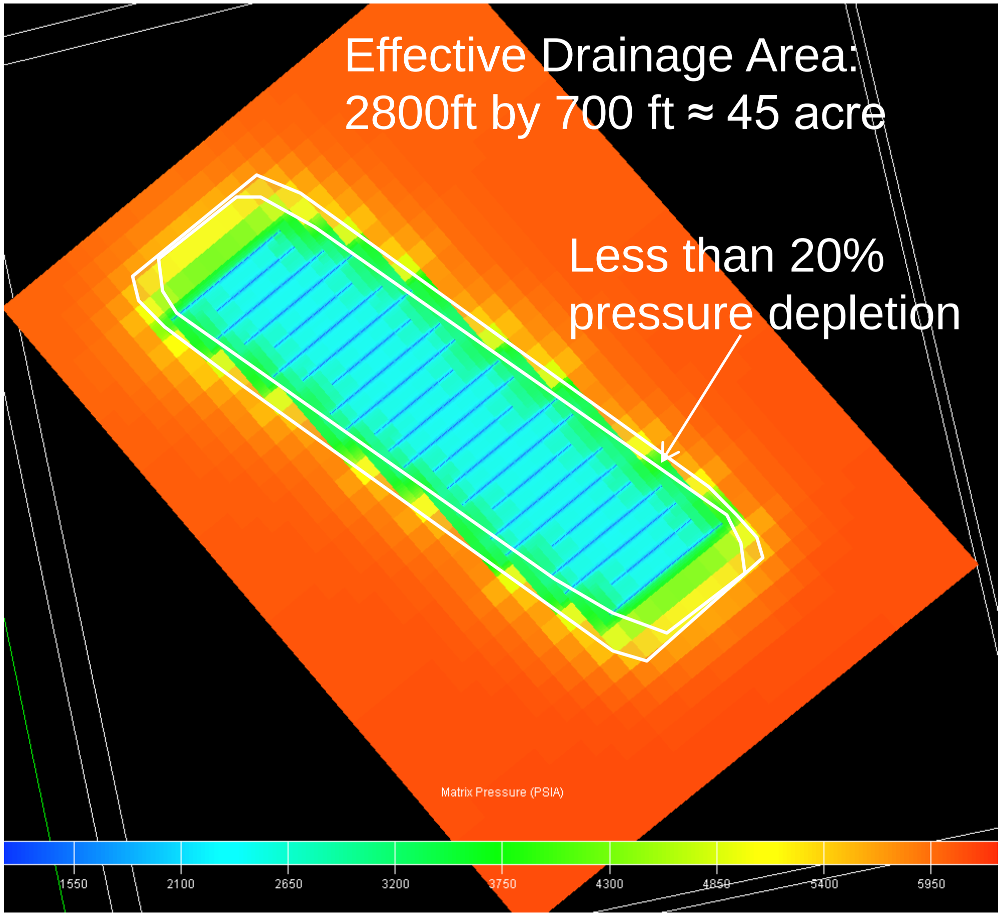


Pressure is always lower in stimulated zone than the surrounding formations

Minimum Gas Flow from Outside Stimulated Area

Gas Rate Matching





After 50 years production

Fate of Frac Water

- Where does frac water go ?

  1. Flowed back from fractures during production 20 – 40 %

  2. Imbibed into the matrix pore space
     - S_w increases 10~50%
     - Minimal K_{rw}
     - Much more viscous than gas
     - Practically immobile (stays in reservoir forever)

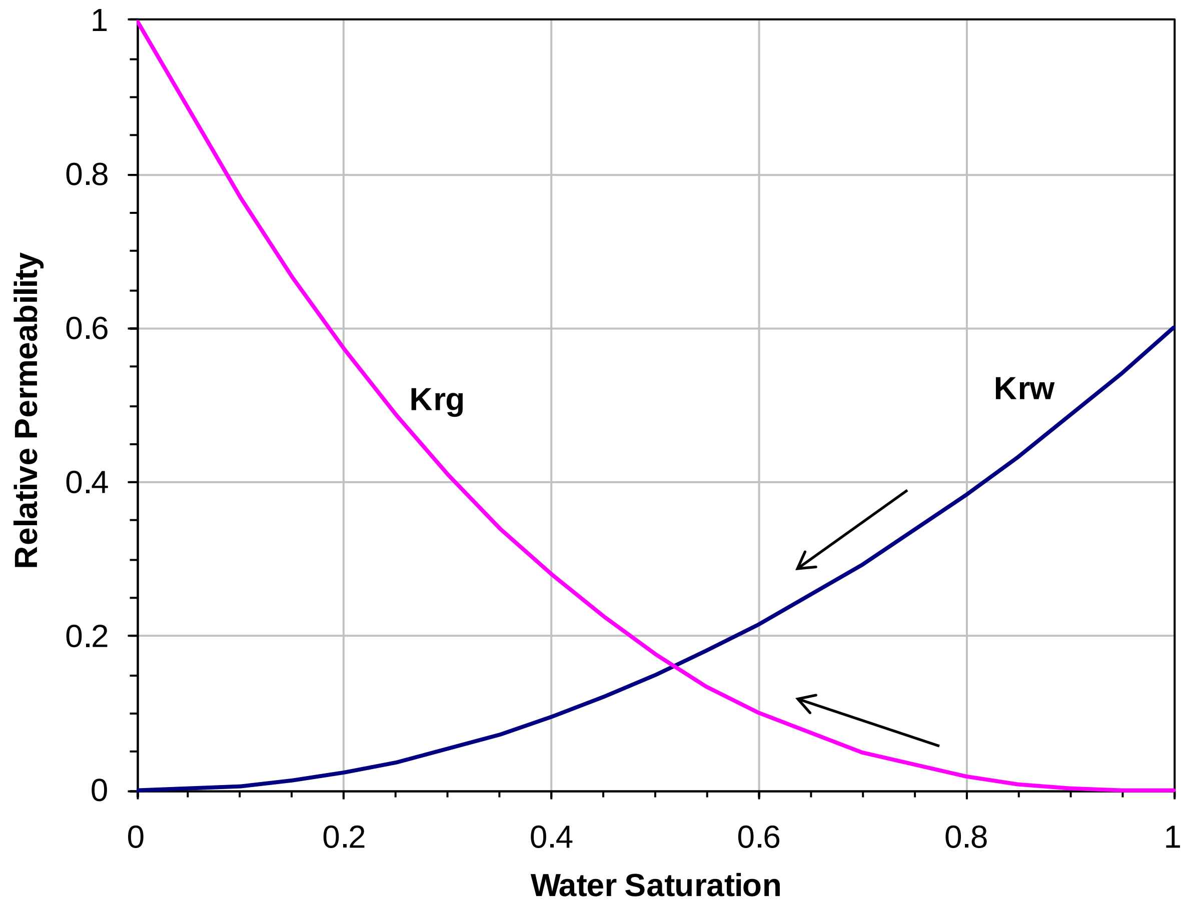
  3. Trapped in disconnected fractures

Flow of Frac Water

- Mainly occurs within propped fractures
- Multiple phase flow
- Water rate quickly declines and become stabilized

$$q_g = \frac{kk_{rg}}{\mu_g} A \nabla p_g$$

$$q_w = \frac{kk_{rw}}{\mu_w} A \nabla p_w$$



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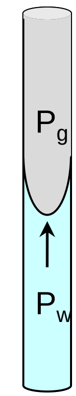
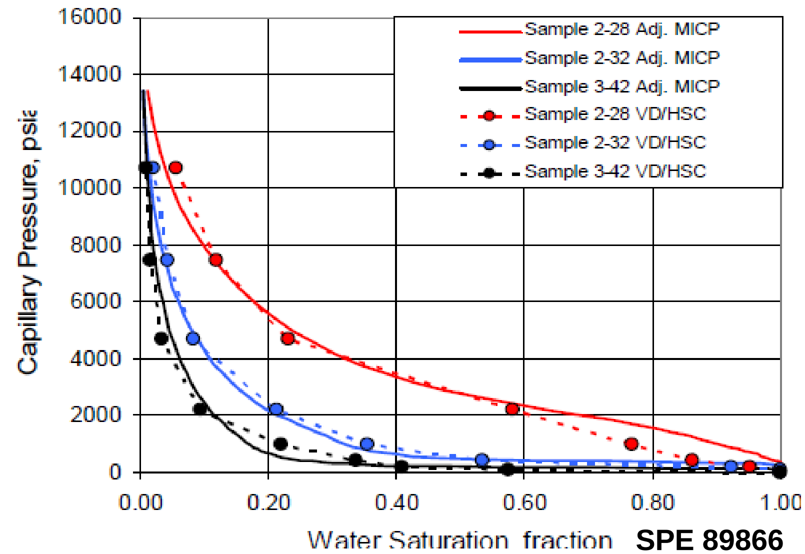
$$p_c = p_g(S_w) - p_w(S_w)$$



3. Trapped in disconnected fractures



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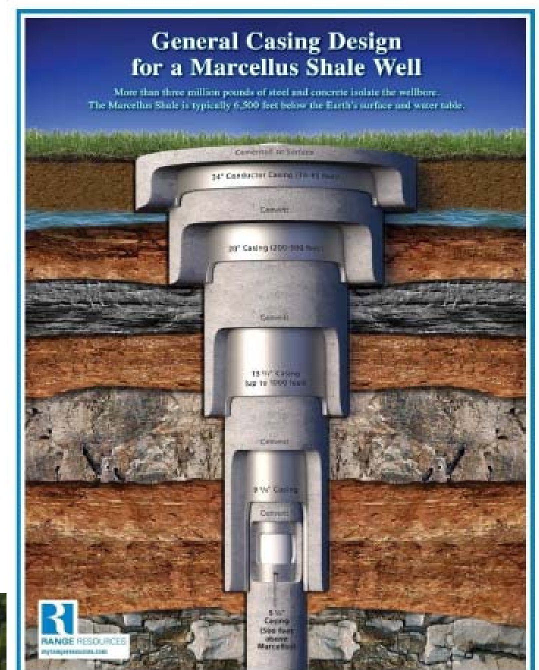
Concluding Remarks

- Pressure gradients drive the flow of gas and water
  - Gas must move into fractures, then to wellbore
  - Water mainly flows within fractures into wellbore
- Physical principles preclude migration of gas and water away from the stimulated zone
- A portion of frac water is produced up the wellbore back to surface
  - Wellbore isolated from surrounding rock by steel casing strings and cement
- Majority of frac water is held by shale formation and becomes immobile



Flow of Gas and Water in Hydraulically Fractured Shale Gas Reservoirs

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Underground fluid flow is primarily controlled by two physical factors: hydraulic conduits and pressure gradients. Both are required, or fluids will not move. In their natural state, shale formations are very impermeable, which means that there are virtually no natural hydraulic conduits in the rock. Because of this, shale has often acted as a cap rock and effectively limited and/or prevented fluids from escaping or migrating into other geologic formations over millions of years (i.e., geologic time).

The flow capacity of the rock can be quantified by permeability. The permeability of the shale matrix typically ranges from tens of nanodarcy to hundreds of nanodarcy (1 nanodarcy equals 10^{-6} microdarcy or 10^{-9} darcy). The shale matrix has such ultra-low permeability because of its very small pore size, which typically is on the order of tens of nanometer. Although natural fractures may exist in shale formations, most of them are filled with minerals in their in-situ conditions.

Because shale is so impermeable in its natural state, technologies such as horizontal drilling and hydraulic fracturing are necessary to enable economical production of gas from these formations. The process of hydraulic fracturing involves creating man-made fractures or fracture networks (i.e., hydraulic conduits) by pumping water and proppants (typically sand) at high rates down the wellbore. By placing proppant into the conduits, they can be held open over time so gas can be effectively produced from the formation. By drilling horizontal wells, multiple hydraulic fractures can be created in a single wellbore, which significantly increases the ability of gas and water to flow out of the shale.

The horizontal and vertical extent of hydraulically induced fractures are typically limited, being confined by such factors as in-situ stress differences, formation leak-off and the relative properties of the target shale formation and surrounding geological strata. When in-situ stress contrasts are high, propagation of the hydraulic fracture is prevented because the stress contrasts serve as a barrier to fracture growth. Even in the absence of stress barriers, formation leak-off will always arrest the fracture height growth, meaning the injected fracturing fluid will be absorbed into the strata with enough porosity and permeability, therefore stopping fracture extension. Typically, hydraulic fractures grow on the order of only a few hundred feet vertically and hundreds of feet horizontally. To evaluate fracture geometry, there is a service industry that collects data during fracture treatments. In addition, numerous hydraulic fracture models have been developed to model fracture geometry. Considering that gas shales are often buried several thousand feet (sometimes more than ten thousand feet) below the surface of the earth, even large hydraulic fractures would still be confined many thousands of feet below the earth's surface.

Not all induced fractures will result in conductive pathways between the formation and the wellbore. After a fracturing treatment, the in-situ stress of the formation will close some of the induced fractures, typically those without proppant. Those unpropped fractures may lose their width, and become disconnected with the propped fractures. Therefore, the effective post-treatment propped fracture lengths and heights are always less than the induced lengths and heights achieved during treatment.

During production, the horizontal wellbore serves as a pressure sink (i.e., the pressure is much lower in the wellbore than in the surrounding shale formation), causing the gas to flow from the shale formation (high pressure environment) into the fractures, and through the fractures to the wellbore (low pressure environment). Since the shale matrix has ultra-low permeability, flow of gas in the unstimulated shale zone is minimal. Virtually no conduits allow water to flow through the unstimulated zone. Consequently, the gas/water movement is within the stimulated zone and towards the wellbore since the pressure gradient is in that direction. Migration of gas and water away from the stimulated zone is precluded.

Wells may be shut-in periodically. During the shut-in, pressure will build up within the stimulated shale zone. However, the pressure within the stimulated zone will be always less than the pressure outside the stimulated zone. A minimum amount of gas will keep flowing from the unstimulated shale zone into the stimulated shale zone. Again, migration of gas and water away from the stimulated zone is precluded.

Fracturing treatment in shale gas reservoirs typically uses water as the fracture fluid to propagate the fractures and transport sands. A portion of this frac water will be produced up the wellbore, which is isolated from the surrounding rock by the steel casing strings and cement, back to surface during production. It is often referred to as flowback water. The flow of water mainly exists within the fractures. Both water and gas flows together as multiphase flow within the fractures toward the wellbore. The flow capacities of water and gas depend on the relative permeabilities of each phase, which are functions of the water saturation in the fractures and matrix. Initial water rates are high, but they decline quickly as water saturation is reduced. The water production typically tends to stabilize at low rates after a short period of production. Over many years, about 20-40 % of the injected water will be produced back.

Since frac water is in contact with the shale matrix through fracture surfaces, water-phase imbibition also plays an important role in water flow. The imbibition effect is caused by the capillary pressure between the gas and water phases. The lower the reservoir permeability, the higher the capillary pressure will be. In low-permeability reservoirs such as shales, the capillary pressure can be thousands of psi. Once water is imbibed into the micropores of the shale matrix, it will quickly become immobile and therefore be retained in the matrix permanently.

As discussed before, some induced but unpropped fractures may lose their width and become disconnected from the propped fractures during the initial flowback period and long-term. In this case, the water filling these fractures will become trapped and remain immobile during production operations.

Because integrated reservoir models consider reservoir geology, the physics of fluid flow in porous media, the nature of the fracturing treatment, production conditions, etc., they can be used to effectively quantify the flow of fluids in subsurface formations. These models show that the injected and produced fluids are contained within the shale formation or in the formations immediately adjacent to them. These formations are thousands of feet below the surface.