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Managing Shut-in Time to Enhance Gas Flow Rate in Hydraulic Fractured Shale Reservoirs: a Simulation Study

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Abstract

Some shale gas and oil wells undergo month-long shut-in times after multi-stage hydraulic fracturing well stimulation. Field data indicate that in some wells, such shut-in episodes surprisingly increase the gas and oil flow rate. In this paper, we report a numerical simulation study that supports such observations and provides a potentially viable underlying imbibition and drainage mechanism. In the simulation, the shale reservoir is represented by a triple-porosity fracture-matrix model, where the fracture forms a continuum of interconnected network created during the well simulation while the organic and non-organic matrices are embedded in the fracture continuum. The effect of matrix wettability, capillary pressure, relative permeability, and osmotic pressure, that is, chemical potential characteristics are included in the model.

The simulation results indicate that the early lower flow rates are the result of obstructed fracture network due to high water saturation. This means that the injected fracturing fluid fills such fractures and blocks early gas or oil flow. Allowing time for the gravity drainage and imbibition of injected fluid in the fracture-matrix network is the key to improving the hydrocarbon flow rate during the shut-in period.

Introduction

Some shale gas and oil wells undergo month-long shut-in times after multi-stage hydraulic fracture stimulation. Field data indicate that in some wells, such shut-in episodes surprisingly increase the gas and oil flow rate. For example, **Fig. 1** shows the effect of an extended shut-in on production of a multi-stage hydraulically fractured well in Marcellus shale (Cheng, 2012). The well was flowed back, after hydraulic fracture stimulation, for a short period before it underwent a six-month shut-in period. When the well was reopened after six months of shut in, gas production rate increased and water production rate decreased significantly. The question is what caused this apparent anomaly?

Water load recovery and flowback behavior

Field experience indicates that water load recovery could be as low as 5% of the total injection volume in Haynesville shale to as high as 50% of that in Barnett and Marcellus shales (King, 2012). Number of mechanisms could contribute to the low-recovery, including extra-trapped water due to changing in natural fractures width that increasing during injection and decreasing during production periods (Economides et al., 2012), water imbibition into shale matrix by capillary pressure (Cheng, 2012).

Flow back water analyzed by Haluszczak et al. (2013) indicates that formation brine in shale basin could be higher than 150,000 ppm, **Fig. 2b**. As the typical fracturing fluid comprises low-salinity water, in many cases it is in the range of 1,000 ppm, significant salinity contrast would be expected. This major salinity difference could lead to substantial chemical potential differences creating large osmotic pressure and driving filtrate from natural fractures into shale matrix block.



Fig. 1 – Field production data from a well in Marcellus shale: (a) water production and (b) gas production. After six-month shut-in, gas production increased and water production decreased substantially (Cheng, 2012).



Fig. 2 – Water load recovery behavior: (a) Load recovery from wells in Horn River shale basin (Economides et al., 2012) and (b) Water salinity profile during flowback and production periods from wells in Marcellus shale basin (Haluszczak et al., 2013).

In this paper, we present the results of a numerical simulation study which replicate similar flow behavior. The reason is that water imbibition into the matrix, augmented by osmotic and capillary pressures, reduces the water saturation while enhancing gas flow into natural fractures to the hydraulic fracture and the wellbore.

Osmotic pressure

Osmotic pressure is generated by the chemical potential difference of solutions across a membrane, which is semi-permeable allowing water molecules but solution ions flowing through (Neuzil, 2000). Water molecules flow from low-salinity solution to high-salinity solution, due to the difference in water activity, until it reaches equilibrium. At the equilibrium, the increase in hydrostatic pressure (p) equals the theoretical osmotic pressure (π), Fig. 3.



Fig. 3 - Diagram demonstrating osmotic pressure: (a) At the initial condition and (b) At the equilibrium condition.

In subsurface environment, clay/shale formations could behave as a membrane, where their pore size approaching the thickness of "double layer" clay surface charges (Marine and Fritz, 1981). Marine and Fritz (1981), Neuzil (2000), and Neuzil and Provost (2009) have reported that high pressure anomalies in geological settings could be created by osmotic pressure. Furthermore, high salinity brine in some formations could be explained by reverse osmosis (Bredehoeft et al., 1963). During burial processes, porous rock has been continuously compressed due to the overburden weight increasing. Consequently, the formation brine has been expelled from the formation. Only water molecules could leave as the membrane-like properties of shale prevents salt ions to escape, thus increasing the formation salinity. High-salinity brine in prolific shale formations could be created by the reverse osmotic process, which indicates the membrane-like properties of the shale formations.

Osmotic pressure (π) is described by (Marine and Fritz, 1981):

$$\pi = (14.5) \frac{RT}{\overline{V}} \ln \frac{a_I}{a_{II}} \tag{1}$$

where,

 a_I, a_{II} water activity of system I and II; low-salinity I and high-salinity II, Water activity for fresh water is 1.0.

R gas constant, equal to 0.082 atm⁻ (kg-mol·K)⁻¹

T temperature, °K

 \overline{V} partial molar volume, *l*/kg-mol

The calculation of water activity for a high-salinity solution requires an iterative computation procedure (Xu et al., 2012). Thus, we used a chemical reaction simulator (TOUGHREACT) for the calculation. **Fig. 4** shows the osmotic pressure, created by the salinity difference between formation brine and low-salinity water. The plot is consistent with the calculation by Marine and Fritz (1981). For the typical injected water (1,000 ppm) and formation brine (150,000 ppm) system in shale reservoirs, the osmotic pressure could be as high as 2,000 psi.



Fig. 4 – Theoretical osmotic pressure created by the salinity difference between formation brine and low-salinity water in fractures at different temperature.

Mathematical model for single phase flow

For single phase water system, we can include osmotic pressure (**Fig. 4**) to a fluid flow equation in fractured rock through transfer function ($\tau_{f/m}$) between fractures and matrix:

$$\tau_{f/m} = \tau_{f/m,p} - \tau_{f/m,\pi} = (0.006328)\sigma \frac{k_m}{\mu} (p_f - p_m) - (0.006328)\sigma \frac{k_m}{\mu} (\pi_f - \pi_m)$$
(2)

where,

,	
k_m	matrix permeability, mD
p_f	pressure in fracture, psi
p_m	pressure in matrix, psi
γ	fluid gradient, psi/ft.
π_{f}	osmotic pressure in fracture calculated from salt concentration using Fig. 4, psi
π_m	osmotic pressure in matrix calculated from salt concentration using Fig. 4, psi
$\tau_{f/m,p}$	transfer function caused by pressure, 1/day
$\tau_{f/m,\pi}$	transfer function caused by osmotic pressure, 1/day

Pressure equations:

Fracture:

$$\nabla \cdot \left(0.006328\right) \left(\frac{k_{f,eff}}{\mu} \nabla p_f\right) + \hat{q} - \tau_{f/m} = \left(\phi c_t\right)_f \frac{\partial p_f}{\partial t}$$
(3)

Matrix:

 $\tau_{f/m} = \left(\phi c_t\right)_m \frac{\partial p_m}{\partial t} \tag{4}$

where,

 $\begin{array}{lll} c_t & \mbox{total compressibility, 1/psi} \\ k_{f,eff} & \mbox{effective fracture permeability, md} \\ \hat{q} & \mbox{sink/source term, 1/day} \\ t & \mbox{time, day} \\ \phi & \mbox{porosity, fraction} \\ \mu & \mbox{fluid viscosity, cp} \end{array}$

Salt concentration equations:

In this paper we assumed that salt is not absorbed on the surface of rock grain. In fracture:

$$\nabla \cdot (0.006328) \left(C_f \frac{k_{f,eff}}{\mu} \nabla p_f \right) + C_f \hat{q} - C_{f/m,p} \tau_{f/m,p} + C_{f/m,\pi} \tau_{f/m,\pi} - \sigma D_{f/m} \left(C_f - C_m \right) = \left(C \phi c_t \right)_f \frac{\partial p_f}{\partial t} + \phi_f \frac{\partial C_f}{\partial t}$$
(5)

In matrix:

$$(C\rho\tau)_{f/m,p} - (C\rho\tau)_{f/m,\pi} + \sigma D_{f/m} (C_f - C_m) = (C\phi c_t)_m \frac{\partial p_m}{\partial t} + \phi_m \frac{\partial C_m}{\partial t}$$
(6)

where,

C_{f}, C_{m}	salt concentration in fracture and matrix, ppm
$D_{f/m}$	diffusion coefficient between fracture and matrix, ft ² /day

To examine the mathematical model, we modeled and compared our simulation to the osmotic pressure measurement for single-phase water in a laboratory conducted by Al-Bazali (2006), for a 3-nd shale sample. Detailed input parameters are shown in **Table 1**. The simulation results indicate a reasonable matching, **Fig. 5**. Initially, the osmotic pressure induced fluid flow from low-salinity to high-salinity and rapidly increased the pressure difference between the shale sample and the small chamber representing a wellbore. This pressure difference, in turn, induced fluid flow from high-salinity formation brine in the shale matrix to low-salinity in the chamber. As a result, it increased salinity in the chamber, thus reducing the salinity contrast, the osmotic pressure, and the pressure difference. The ratio between the final osmotic pressure and the theoretical osmotic pressure is the membrane efficiency. In this experiment, the efficiency is less than 1%.

TABLE 1 – INPUT PARAMETERS FOR THE NUMERICAL SIMULATION MODEL COMPARING TO LABORATORY DATA		
Parameters	Value	
Diffusion coefficient*, ft ² /d	10 ⁻⁸	
Permeability , md	0.000003	
Equivalent salinity in shale, ppm	100,000	
Equivalent initial salinity in wellbore, ppm	10,000	

* Low value due to membrane effect



Fig. 5 – Comparison between experimental data (adopted from Al-Bazali, 2006) and numerical simulation results for a 3-nd shale sample.

Neuzil and Provost (2009) have thoroughly reviewed public experimental data and reported consistently low membrane efficiency, lower than 1%. They have argued that the low membrane efficiency measured in laboratories is caused by thin shale specimen whereas shale formation is much thicker. Also, these experiments have been conducted in a single-phase system. We believe that in shale reservoirs, where the initial water saturation in shale matrix approaching the irreducible water saturation, water flowing from shale matrix to fractures would be minimal. Thus, it allows the osmotic pressure to draw low-salinity water into a shale matrix block.

Pore morphology in shale formations and an idealized pore network connection

Prolific shale formations are often overmature and yield high porosity in organic matter, as high as 50%, produced from digenesis process (Passey et al., 2010). This type of pore provides storage and connection in organic material, **Fig. 6a** showing the pore structure in organic matter from a high-resolution scanning-electron microscopy of ion-beam milled Barnett shale sample. Some parts of shale formation can contain non-organic material such as silica grain, quartz, and clay, which are waterwet rocks. These non-organic and organic rocks coexist in shale formations. Thus, we can idealize shale matrix as the combination of organic and non-organic matrix blocks, **Fig. 6b**. Mathematically, we describe shale pore network as a triple-porosity system including fractures, non-organic, and organic matrices, **Fig. 7**. Each matrix pore type could connect to natural fractures, which provide high permeability flow path to hydraulic fractures and a wellbore.



Fig. 6 – Pore morphology and fluid distribution in shale formations: (a) Ion-milled SEM image of a Barnett organic rich shale (Passey et al., 2010), (b) idealized pore network cartoon and fluid content.



Fig. 7 – Idealized pore-network connection of fractured rocks: (a) Classical dual-porosity and (b) Triple-porosity for organic-rich shale formations

Mathematical model for gas-water in triple porosity system

For mass transfer, we use both osmotic and capillary imbibition. Matrix block is subdivided into non-organic and organic matrices. Non-organics include water-wet silicates, quartz, clays, and calcite. We assumed gas adsorption occurs only on organic material.

Pressure equations:

Fracture:

$$\nabla \cdot (0.006328) k_{f,eff} \left[\lambda_{tf} \nabla p_{gf} - \left(\lambda_{wf} \gamma_w + \lambda_{gf} \gamma_g \right) \nabla D \right] + \hat{q}_t - \tau_{t,f/m1} - \tau_{t,f/m2} = \left(\phi c_t \right)_f \frac{\partial p_{gf}}{\partial t}$$
(7)

Non-organic matrix:

$$\tau_{t,f/m1} - \tau_{t,m1/m2} = \left(\phi c_t\right)_{m1} \frac{\partial p_{gm1}}{\partial t}$$
(8)

Organic matrix:

$$\tau_{t,f/m2} + \tau_{t,m1/m2} = \left(\phi c_t\right)_{m2} \frac{\partial p_{gm2}}{\partial t} + \left(\frac{\rho_s \left(VF_2 - \phi_{m2}\right) B_g}{2200} \frac{a_\infty b}{\left(1 + bp_{gm2}\right)^2}\right) \frac{\partial p_{gm2}}{\partial t}$$
(9)

where,

maximum gas absorption, scf/ton
Longmuir coefficient, 1/psi
gas formation volume factor, cf/scf
depth, ft
gas pressure in fracture, non-organic and organic matrices, psi
capillary pressure of gas-water system, psi
volume fraction for organics matrix
gas and water gradient, psi/ft
gas, water, and total mobility, 1/cp
rock density, lb/ft ³
total transfer function between fracture and non-organic, and fracture and organic rocks, 1/day. Full equation
forms can be found in Appendix A.

Saturation equations:

Fracture:

$$\nabla \cdot (0.006328) k_{f,eff} \left[\lambda_{wf} \nabla p_{gf} - \lambda_{wf} \gamma_{w} \nabla D \right] + \hat{q}_{w} - \tau_{w,f/m1} - \tau_{w,f/m2} = \phi_{f} S_{wf} \left(c_{\phi f} + c_{w} \right) \frac{\partial p_{gf}}{\partial t} + \phi_{f} \frac{\partial S_{wf}}{\partial t}$$
(10)

Non-organic matrix:

$$\tau_{w,f/m1} - \tau_{w,m1/m2} = \phi_{m1} S_{wm1} \left(c_{\phi m} + c_w \right) \frac{\partial p_{gm1}}{\partial t} + \phi_{m1} \frac{\partial S_{wm1}}{\partial t}$$
(11)

Organic matrix:

$$\tau_{w,f/m2} + \tau_{w,m1/m2} = \phi_{m2} S_{wm2} \left(c_{\phi m} + c_w \right) \frac{\partial p_{gm2}}{\partial t} + \phi_{m2} \frac{\partial S_{wm2}}{\partial t}$$
(12)

Salt concentration equations:

Fracture:

$$\nabla \cdot (0.006328) C_f k_{f,eff} \left[\lambda_{wf} \nabla p_{gf} - \lambda_{wf} \gamma_w \nabla D \right] + C_f \hat{q}_w - C_{f/m1,p} \tau_{w,f/m1,p} + C_{f/m1,\pi} \tau_{w,f/m1,\pi} - \sigma_{f/m1} D_{f/m1} \left(C_f - C_{m1} \right) - C_{f/m2,p} \tau_{w,f/m2,p} + C_{f/m2,\pi} \tau_{w,f/m2,\pi}$$
(13)
$$- \sigma_{f/m2} D_{f/m2} \left(C_f - C_{m2} \right) = C_f \phi_f S_{wf} \left(c_{\phi f} + c_w \right) \frac{\partial p_{gf}}{\partial t} + C_f \phi_f \frac{\partial S_{wf}}{\partial t} + \phi_f S_{wf} \frac{\partial C_f}{\partial t}$$

Non-organic matrix:

$$C_{f/m1,p}\tau_{w,f/m1,p} - C_{f/m1,\pi}\tau_{w,f/m1,\pi} + \sigma_{f/m1}D_{f/m1} \left(C_{f} - C_{m1}\right) - C_{m1/m2,p}\tau_{w,m1/m2,p} + C_{m1/m2,\pi}\tau_{w,m1/m2,\pi} - \sigma_{m1/m2}D_{m1/m2} \left(C_{m1} - C_{mf}\right) = C_{m1}\phi_{m1}S_{wm1} \left(c_{\phi m} + c_{w}\right)\frac{\partial p_{gm1}}{\partial t} + C_{m1}\phi_{m1}\frac{\partial S_{wm1}}{\partial t} + \phi_{m1}S_{wm1}\frac{\partial C_{m1}}{\partial t}$$
(14)

Organic matrix:

$$C_{f/m2,p}\tau_{w,f/m2,p} - C_{f/m2,\pi}\tau_{w,f/m2,\pi} + \sigma_{f/m2}D_{f/m2} \left(C_{f} - C_{m2}\right) + C_{m1/m2,p}\tau_{w,m1/m2,p} - C_{m1/m2,\pi}\tau_{w,m1/m2,\pi} + \sigma_{m1/m2}D_{m1/m2} \left(C_{m1} - C_{mf}\right)$$
(15)
$$= C_{m2}\phi_{m2}S_{wm2} \left(c_{\phi m} + c_{w}\right)\frac{\partial p_{gm2}}{\partial t} + C_{m2}\phi_{m2}\frac{\partial S_{wm2}}{\partial t} + \phi_{m2}S_{wm2}\frac{\partial C_{m2}}{\partial t}$$

where,

 $C_{fr} C_{ml}, C_{m2}$ Salt concentration in fracture, non-organic and organic matrices, ppm $\tau_{wf/m1}, \tau_{wf/m2}$ water transfer function between fracture and non-organic, and fracture and organic rocks, 1/day. Full equation form of transfer functions can be found in **Appendix A**.

Numerical simulation study

A 2-D sector model was constructed to represent a section covers one bi-wing hydraulic fracture, **Fig. 8**. The shale reservoir is represented by a triple-porosity fracture-matrix model, where the fracture forms a continuum of interconnected network created during the well simulation while the organic and non-organic matrices are embedded in the fracture continuum. Explicit orthogonal grids are assigned as a static hydraulic fracture with the dimensionless fracture conductivity of 10. Logarithmic grid size distribution near the hydraulic fracture is used to capture flow behavior near the fracture. No fracture propagation was modeled. Detailed reservoirs and hydraulic fracture input data can be found in **Table 2** and **Fig. 9**.

The simulation was initialized by injecting 5,000 bbl of fracturing fluid into the model to create the post-fracturing water saturation distribution near the hydraulic fracture. Then, the well was shut-in for various period of time to investigate the effect of shut-in to the subsequent production.



Fig. 8 - Model schematic: a 2-D sector model



(a) (b) Fig. 9 – Relative permeability and capillary pressure for water-wet rock, non-water-wet rock, and fractures: (a) relative permeability and (b) capillary pressure.

TABLE 2 – INPUT PARAMETERS: A 2-D SECTOR MODEL			
Parameter	Natural fractures (f)	<u>Non-organic rock (m1)</u>	<u>Organic rock (m2)</u>
Effective permeability, md	0.01	0.0001	0.0001
Effective porosity, fraction	0.0015	0.054	0.030
Irreducible water saturation, fraction	0.05	0.40 (water-wet) 0.05 (non-water-wet)	0.05
Capillary pressure at irreducible water saturation, psi	1.0	1000.0 (water-wet) 1.0 (non-water-wet)	10.0
Volume fraction, fraction	-	0.9	0.1
Shape factor, 1/ft ²	0.30 (f-m1)	0.10 (m1-m2)	0.03 (f-m2)
Salt diffusion coefficient, ft ² /day	10 ⁻⁸ (f-m1)	10 ⁻⁸ (m1-m2)	10 ⁻⁸ (f-m2)
Formation brine salinity, ppm	150,000	150,000	150,000
Gas absorption coefficient <i>Maximum gas absorption, scf/ton</i> Longmuir coefficient, 1/psi	n/a	n/a	2000* 0.00044

* Higher than a typical value because it only applies to the organic rock volume while the typical value is the weighted average absorption value for whole rocks including non-organic rock.

TABLE 3 – NUMERICAL SIMULATION CASES					
Simulation	Pore fabric connection			Osmotic	Non-organic rock
cases	<u>f-m1</u>	<u>f-m2</u>	<u>m1-m2</u>	pressure	type
(a) WW+OSP	\checkmark	\checkmark	\checkmark	\checkmark	Water-wet rock
(b) NW+OSP	\checkmark	\checkmark	\checkmark	\checkmark	Non-water-wet rock
(c) WW+NOOSP	\checkmark	\checkmark	\checkmark		Water-wet rock
(d) NW+NOOSP	\checkmark	\checkmark	\checkmark		Non-water-wet rock

To investigate the role of matrix wettability, capillary pressure, relative permeability characteristics, and osmotic pressure, four simulation cases were run. Each case represents different combination of rock matrix wettability including water-wet and non-water-wet rock, and the presence of osmotic pressure. The summary of simulation cases is shown in **Table 3**. Different shut-in periods including 0, 7, 15, and 30 days shut-in period, were included in the simulation cases.

Simulation results

Fig. 10 shows the comparison between capillary-induced and osmotic-induced fluid flux from fracture to matrix at 60 ft away from hydraulic fracture plane, from the simulation case (a). Positive value indicates flux from the fractures to shale matrix block. The flux term induced by osmotic pressure is four times higher than that of capillary pressure because significant salt concentration difference between fracturing fluid and formation brine.



Fig. 10 –Comparison of flux terms from fractures to matrix at 60 ft away from fracture face: In this plot, positive value indicates fluid flow from fracture to matrix.

The effect of shut-in period on gas production rate for each simulation case is shown in **Fig. 11**. The simulation results from Case (a), (b), and (c) show significant early gas rate improvement after shut-in periods. The main reason for the improvement is because of mass transfer of filtrate into the matrix by gravity, capillary and/or osmotic mass transfer during the shut-in period. Initially, the natural fractures which are main flow path between shale matrix to the hydraulic fracture and the wellbore are fully saturated with fracturing fluid, blocking the flow path. The shut-in periods allow matrix to imbibe the filtrate and clean up the fluid flow path inside the fractures, thus allow higher gas production rate. On the other hand, the simulation results for Case (d) indicate minimal gas rate improvement because there is no driven force for imbibition as the rock is non-water-wet rock and no osmotic pressure is taking into account. Nevertheless, the early rate improvement does not last very long. After a couple of months, the gas production rate converges to a stabilized rate. The long term gas recovery in all simulation cases are no affected by the early gas rate improvement, (**Fig. 12**).

Fig. 13 shows water load recovery from various shut-in periods. Again, Case (a), (b), and (c) indicate less water load recovery after shut-in period from reducing from $\sim 20\%$ to $\sim 10\%$ because some of the filtrate is imbibed into shale matrix. Furthermore, Fig. 14 shows salinity profile during production. Initially, the salinity is low as most of the produced water comes from fracturing fluid. Later, formation brine from inside the shale matrix start to produce when the pressure difference between the fractures and matrix overcomes the capillary pressure.



Fig. 11 –Simulation results, gas production rate after long shut-in period for: (a) case WW-OSP: Water-wet rock with osmotic pressure effect, (b) case NW-OSP:Non-water-wet rock with osmotic pressure effect, (c) case WW-NOOSP: Water-wet rock without osmotic pressure effect, (b) case NW-NOOSP:Non-water-wet rock with osmotic pressure effect.



Fig. 12 – Simulation results, gas cumulative production for: (a) case WW-OSP: Water-wet rock with osmotic pressure effect, (b) case NW-OSP:Non-water-wet rock with osmotic pressure effect, (c) case WW-NOOSP: Water-wet rock without osmotic pressure effect, (b) case NW-NOOSP:Non-water-wet rock with osmotic pressure effect



Fig. 13 – Simulation results, cumulative water production for: (a) case WW-OSP: Water-wet rock with osmotic pressure effect, (b) case NW-OSP:Non-water-wet rock with osmotic pressure effect, (c) case WW-NOOSP: Water-wet rock without osmotic pressure effect, (b) case NW-NOOSP:Non-water-wet rock with osmotic pressure effect, (b) case NW-NOOSP:Non-water-wet rock with osmotic pressure effect.



Fig. 14 – Simulation results, cumulative water production for: (a) case WW-OSP: Water-wet rock with osmotic pressure effect, (b) case NW-OSP:Non-water-wet rock with osmotic pressure effect, (c) case WW-NOOSP: Water-wet rock without osmotic pressure effect, (b) case NW-NOOSP:Non-water-wet rock with osmotic pressure effect.

Conclusions

In this paper, we report the development of a mathematical model to include gravity, capillary, and osmotic pressure effects in a triple-porosity system for organic-rich shale formations. The osmotic pressure model is based on experimental data. We also conducted the numerical experiments to investigate the effect of the post-fracturing long shut-in periods on the initial gas production rate and fracturing fluid recovery. The following conclusion can be drawn from the simulation results:

- 1. We have been able to simulate the effect of shut-in of newly created hydraulic fractures on increased production of gas in organic-rich shale reservoirs. The results are similar with field data reported in literature.
- 2. The reason for the increase in gas production is because of mass transfer of filtrate into the matrix by gravity, capillary and/or osmotic mass transfer during the shut-in period, which reduces the liquid saturation in natural fractures and allows gas to flow at higher rates from the fractures.
- 3. The rate increase is not a lasting effect and depends on the nature of pore connectivity.

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Nomenclature

a_I	water activity of system I, dimensionless
с	compressibility, 1/psi
С	salt concentration, ppm
D	depth, ft
$D_{f/m}$	diffusion coefficient between fracture and matrix, ft ² /day
k	permeability, md
р	pressure, psi
\hat{q}	sink/source term, 1/day
R	gas constant, equal to 0.082 atm ⁻ (mol ⁻ K) ⁻¹
t	time, day
Т	temperature, K
\overline{V}	partial molar volume, l/mol

Greek letter

ϕ	porosity, fraction
γ	fluid gradient, psi/ft
λ	mobility, 1/cp
μ	viscosity, cp
π	osmotic pressure, psi
τ	transfer function, 1/day

Subscript

eff	effective
f	fracture
f/m1	between fracture and non-organic matrix
f/m2	between fracture and organic matrix
g	gas phase
m1/m2	between non-organic and organic matrices
m1, m2	non-organic and organic matrices
р	pressure term
t	total phase
w	water phase
π	osmotic pressure term

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Appendix A – Transfer functions

Fracture (f) – non-organic matrix (m1) connection:

$$\tau_{t,f/m1} = \tau_{w,f/m1,p} - \tau_{w,f/m1,\pi} + \tau_{g,f/m1,p}$$
(A-1)

$$\tau_{w,f/m1,p} = (0.006328)\sigma_{f/m1}k_m\lambda_{wf/m1} \left[\left(p_{gf} - p_{gm1} \right) - \left(p_{cgwf} - p_{cgwm1} \right) + \frac{\sigma_{z,f/m1}}{\sigma_{f/m1}} \gamma_w \left(h_{wf} - h_{wm1} \right) \right]$$
(A-2)

$$\tau_{g,f/m1,p} = (0.006328)\sigma_{f/m1}k_m\lambda_{gf/m1} \left[\left(p_{gf} - p_{gm1} \right) - \frac{\sigma_{z,f/m1}}{\sigma_{f/m1}} \gamma_g \left(h_{wf} - h_{wm1} \right) \right]$$
(A-3)

$$\tau_{w,f/m1,\pi} = (0.006328) \sigma_{f/m1} k_m \lambda_{wf/m1} E_{osp} \left(\pi_f - \pi_{m1} \right)$$
(A-4)

Fracture (f) – organic matrix (m2) connection:

$$\tau_{t,f/m2} = \tau_{w,f/m2,p} - \tau_{w,f/m2,\pi} + \tau_{g,f/m2,p}$$
(A-5)

$$\tau_{w,f/m2,p} = (0.006328)\sigma_{f/m2}k_m\lambda_{wf/m2} \left[\left(p_{gf} - p_{gm2} \right) - \left(p_{cgwf} - p_{cgwm2} \right) + \frac{\sigma_{z,f/m2}}{\sigma_{f/m2}}\gamma_w \left(h_{wf} - h_{wm2} \right) \right]$$
(A-6)

$$\tau_{g,f/m2,p} = (0.006328)\sigma_{f/m2}k_m\lambda_{gf/m2} \left[\left(p_{gf} - p_{gm2} \right) - \frac{\sigma_{z,f/m2}}{\sigma_{f/m2}} \gamma_g \left(h_{wf} - h_{wm2} \right) \right]$$
(A-7)

$$\tau_{w,f/m2,\pi} = (0.006328) \sigma_{f/m2} k_m \lambda_{wf/m2} E_{osp} \left(\pi_f - \pi_{m2} \right)$$
(A-8)

Non-organic matrix (m1) – organic matrix (m2) connection:

$$\tau_{t,m1/m2} = \tau_{w,m1/m2,p} - \tau_{w,m1/m2,\pi} + \tau_{g,m1/m2,p}$$
(A-9)

$$\tau_{w,m1/m2,p} = (0.006328)\sigma_{m1/m2}k_m\lambda_{wm1/m2} \left[\left(p_{gm1} - p_{gm2} \right) - \left(p_{cgwm1} - p_{cgwm2} \right) + \frac{\sigma_{z,m1/m2}}{\sigma_{m1/m2}}\gamma_w \left(h_{wm1} - h_{wm2} \right) \right] (A-10)$$

$$\tau_{g,m1/m2,p} = (0.006328)\sigma_{m1/m2}k_m\lambda_{gm1/m2} \left[\left(p_{gm1} - p_{gm2} \right) - \frac{\sigma_{z,m1/m2}}{\sigma_{m1/m2}} \gamma_g \left(h_{wm1} - h_{wm2} \right) \right]$$
(A-11)

$$\tau_{w,m1/m2,\pi} = (0.006328)\sigma_{m1/m2}k_m\lambda_{wm1/m2}E_{osp}(\pi_{m1} - \pi_{m2})$$
(A-12)