Accepted Manuscript

Thermal cooling to improve hydraulic fracturing efficiency and hydrocarbon production in shales

Saeid Enayatpour, Eric van Oort, Tad Patzek

PII: S1875-5100(18)30536-5

DOI: <https://doi.org/10.1016/j.jngse.2018.12.008>

Reference: JNGSE 2789

To appear in: *Journal of Natural Gas Science and Engineering*

Received Date: 11 August 2018

Revised Date: 6 December 2018

Accepted Date: 9 December 2018

Please cite this article as: Enayatpour, S., van Oort, E., Patzek, T., Thermal cooling to improve hydraulic fracturing efficiency and hydrocarbon production in shales, *Journal of Natural Gas Science & Engineering*, <https://doi.org/10.1016/j.jngse.2018.12.008>.

This is a PDF file of an unedited manuscript that has been accepted for publication. As a service to our customers we are providing this early version of the manuscript. The manuscript will undergo copyediting, typesetting, and review of the resulting proof before it is published in its final form. Please note that during the production process errors may be discovered which could affect the content, and all legal disclaimers that apply to the journal pertain.

Thermal Cooling to Improve Hydraulic Fracturing Efficiency and Hydrocarbon Production in Shales

Saeid Enayatpour^{a,*}, Eric van Oort^a, Tad Patzek^b

^a*Petroleum and Geosystems Engineering, The University of Texas at Austin, TX, USA*

^b*Earth Science and Engineering Department, King Abdullah University of Science and Technology*

Abstract

Unconventional hydrocarbon reserves contained in oil and gas shale formations are proving themselves to be abundant sources of current and future energy supply, unlocked through the technologies of horizontal drilling and hydraulic fracturing. Despite the various technology improvements that have buoyed the "shale revolution" in the last decade, there remain very significant opportunities to further improve hydrocarbon recovery from shales by making hydraulic fracturing more efficient. In this paper, we look into the possibility of stimulating a rock matrix to a higher degree with hydraulic fractures by deliberately cooling down the rock. Cooling reduces in-situ thermal stress, which lowers initiation and propagation pressures of hydraulic fractures. Moreover, when a laterally confined solid undergoes temperature reduction induced by cooling, a thermal stress gradient is developed in the solid body. We perform sensitivity analyses to show that in an in-homogenous shale, this thermal stress gradient can lead to differential contraction of its various mineralogical constituents, which in turn may create thermal cracks. The opening of such cracks increases shale permeability and provides additional pathways for the flow of hydrocarbons, thereby enhancing productivity. Here, we solve the coupled equations of stress, heat transfer and flow using finite element techniques for hydraulic stimulation amplified by cooling. It is shown that thermal cracks in tight formations induced by thermal cooling have the potential to improve the productivity of horizontal wellbores placed in shale by an estimated 16% for the case of methane gas flow through thermally stimulated shale of micro-darcy permeability.

Keywords: Thermal Stimulation, Thermal Rock Fracturing, Cohesive zone method (CZM), Hydraulic Fracturing, Response Surface Methodology, Central Composite Design

*Corresponding author

Email address: s.e@utexas.edu (Saeid Enayatpour)

1. Introduction

Shale oil and gas reservoirs are abundant, not only in Northern America but in various places around the globe, (Selley, 2012; J.R.V. Brooks, 2001; Swann and Munns, 2003; Horsrud et al., 1998). These reservoirs will play a progressively increasing role in meeting current and future energy needs.

Successful production of oil and gas from shales with nano-Darcy range permeability is only possible through large-scale hydraulic fracturing (Peebles, 1980; Donohue et al., 1981; Zielinski and McIver, 1981; Zou et al., 2010; Chen et al., 2011; Huang et al., 2012) to create extensive surface area and enhance permeability to facilitate hydrocarbon flow. With current state-of-the-art technology, only 5-15% of the hydrocarbons in place can be produced during primary recovery (Lake, 1989).

Ways of improving hydraulic fracturing efficiency and hydrocarbon recovery are continuously being explored, however, from straightforward manipulation of hydraulic pressure and injection flow rate, changing well and frac spacings, increasing proppant loading, etc., to more elaborate techniques that for instance aim to favorably manipulate in-situ stress contrasts, (Patel et al., 2016; Sierra et al., 2014; Settari and Warren, 1994; Chen et al., 1995; Wojnarowski and Rewis, 2005; Dunn-Norman et al., 2009). In this paper, it is shown that hydraulic fracturing can be enhanced by cooling down the wellbore and the fracture surfaces, i.e. augmenting hydraulic fracturing with thermo-mechanical (TM) fracturing. Heat diffuses relatively easily in shales. Cooling of shales in the near-wellbore region and along the fracture surfaces can be readily accomplished, and will generate significant tensile stresses in the rock matrix. This may trigger local rock failure and the generation of thermal cracks, since shales are generally weak in tension (Gao et al., 2015). In turn, the thermal cracks will create new surface area and enhance permeability for hydrocarbon flow. It is a well known fact that injection of cold fluid into reservoir rock leads to thermal cracking. This has been observed in the injection of CO₂ for sequestration purposes and in research studies of thermal loading on rock properties (Kim and Kemeny, 2009; Keaney et al., 2004; Enayatpour et al., 2018). It has also been observed in drilling that circulating cool drilling fluid across downhole formations leads to a lowering of the near-wellbore tangential stress, with associated induced fracturing and lost circulation events (Hetttema et al., 2004).

From a practical perspective, there are two ways in which the wellbore and hydraulic fracture(s) could be effectively cooled:

- Cooling down the wellbore prior to or after perforating and prior to hydraulic fracturing. This will generate thermal cracks primarily in the near-wellbore region, i.e., the region that has been effectively cooled and where temperature is effectively lowered compared to native in-situ values. Such cooling could be achieved by circulating as simple a fluid as chilled water

downhole, or by using more exotic options such as liquid CO₂. Note that the effect of such cooling on the well design, particularly the stress state of the casing and the surrounding cementation, needs to be explicitly addressed.

- Cooling down the fracture itself by injecting a cold fluid as part of the hydraulic fracturing job. Again, this fluid could simply be chilled water or more exotic cold fracturing fluids (such as CO₂, LPG, etc.). There also may exist an innovative way to amplify the cooling of a fracture by using an endothermic reaction taking place in the hydraulic fracturing fluid itself. An endothermic reaction is a reaction that absorbs heat from the surrounding environment in order to achieve an increase in entropy (ΔS). Such a reaction leads to a lower Gibbs free energy (ΔG), even if the enthalpy of the reaction products (ΔH) is higher. Of course, cooling effects already play a role in making current hydraulic fractures more effective. In current slick water fracs, large amounts of relatively cool water are injected into downhole fractures, which will cool down the wellbore and the fractures themselves, leading to lower in-situ thermal stress and induced thermal fracturing. Our argument here is to deliberately amplify this cooling effect by cooling down the wellbore and the fracture(s) more than is currently already (unknowingly) achieved.

2. Theory

2.1. General

The following rock mechanical parameters and factors play a major role in thermal fracturing / cracking induced by cooling:

- The stiffness of the rock as characterized by its Young's Modulus (E) and Poisson's Ratio (ν), which directly affect the magnitude and facility of thermal fracturing, as discussed below. Some shales are extremely stiff, others less so. An example of a very stiff shale is the Qiongzhusi Shale in China with a modulus of elasticity of 60 GPa, which is an order of magnitude larger than that of the Marcellus shale with a modulus of elasticity of only 6 GPa (Lau and Yu, 2013).
- The coefficient of thermal expansion α , which directly affects the ease and extent of thermal crack initiation.
- The applied temperature gradient for cooling the rock, having a direct effect on crack initiation and propagation.

- 65 • Lateral confinement of rock. The lateral boundary plays an important role: the more the rock is confined, the less compliance it will exhibit to an applied thermal cooling load, leading to easier crack initiation and propagation.
- The thermal conductivity of the rock, which affects the dynamics of heat diffusion in the rock and the extent around either the wellbore or the fracture surfaces where efficient cooling takes place. Moreover, a progression of cracks reduces the thermal conductivity coefficient of the 70 bulk rock.
- Rock tensile strength and fracture toughness, which affect the level of resistance of material to brittle rupture. The lower the fracture toughness, the more brittle the fracture will be, with less energy required for rupturing the rock.
- 75 • The magnitude of the effective in-situ stress, particularly the effective stress, parallel to the primary hydraulic fracture. This effective in-situ stress will typically be the maximum effective horizontal stress, against which thermal cracks will open perpendicular to the primary hydraulic fracture, as discussed below.
- The presence of natural fractures and the degree to which thermal fractures can aid in linking 80 up the hydraulic fracture with the network of natural fractures.

The facility of thermally enhanced fracturing is directly proportional to Young's Modulus and coefficient of thermal expansion, and inversely proportional to the tensile strength/fracture toughness of the rock and the maximum effective horizontal stress magnitude. In the work discussed here, we impose thermal shrinkage on a shale rock formation with certain elastic and thermal properties 85 which is laterally confined. An equilibrium approach to fracturing is taken, i.e., we are not concerned with how fast a fracture propagates in time, but rather to what extent a low-permeability shale rock develops thermal cracks in response to an applied thermal cooling load. We then estimate the permeability improvement, ultimately yielding an improvement in hydrocarbon recovery which results from the appearance of these thermal cracks.

90

2.2. *Effect of Cooling on Fracture Initiation and Propagation*

In hydraulic fracturing, hydraulic pressure is used to overcome the in-situ formation stress (and formation tensile strength, which usually only plays a minor role) to create massive fracture net- 95 works to stimulate the production of hydrocarbons in tight rocks such as shales and tight sands.

The in-situ stress is a function of formation temperature – the higher the temperature, the higher the in-situ stress, but the reverse is true also: the lower the temperature, the lower the in-situ stress and the easier it becomes to fracture. Here, it is proposed to manipulate the formation temperature during the hydraulic fracturing process actively. More precisely, in-situ formation temperature is actively lowered prior to and/or during hydraulic fracturing, in turn lowering the in-situ formation stress and in turn lowering the threshold for fracture initiation and propagation. Thereby, the same hydraulic fracture may be pumped at lower hydraulic pressure and pump horsepower. Similarly, for the same pump hydraulic horsepower larger volumes and rates of fracturing fluid can be pumped, leading to larger and more extensive fracture networks in a formation that has been actively cooled.

The effect of temperature on the wellbore wall is time-dependent, such that the longer the rock is in contact with the wellbore fluid, the further away from the hole the temperature perturbation will propagate. In a simplified approach, one can assume that the material is impermeable (a reasonable assumption for ultra-low permeability materials such as shales). In this case, a relatively simple integral equation can be written for the magnitude of $\Delta\sigma_{\theta\theta}^{\Delta T}$, the variation of the tangential stress around the wellbore as a function of radial position r and time t due to temperature effects (Stephens and Voight (1982)). Although the exact solution for the temperature distribution near a constant-temperature wellbore is a series expansion, solutions exist which approximate the temperature in the near wellbore region using only the first two terms of the expansion as shown in Equation (1), (Ritchie and Sakakura, 1956):

$$\Delta\sigma_{\theta\theta}^{\Delta T} = \left[\frac{\alpha E \Delta T}{1 - \nu} \right] \left[\left(\frac{1}{2\rho} - \frac{1}{2} - \ln \rho \right) I_0^{-1} - \left(\frac{1}{2} + \frac{1}{2\rho} \right) \right] \quad (1)$$

where: $\rho = \frac{r}{a}$; $I_0^{-1} = \frac{1}{2\pi i} \int_{-\infty}^0 \frac{e^{[4\tau z / \sigma^2]z}}{z \ln z} dz$

Once steady state has been reached, the change of the tangential stress around the wellbore is given by Equation (2), (Charlez, 1991, 1997):

$$\Delta\sigma_{\theta\theta}^{\Delta T} = \left[\frac{\alpha E \Delta T}{1 - \nu} \right] \quad (2)$$

Where α is the linear coefficient of thermal expansion, E and ν are the static Young's Modulus and the Poisson's Ratio of the rock respectively, and ΔT is the temperature difference between the

borehole fluid and the in-situ formation (note that ΔT is negative if the fluid in the borehole is cooler than the formation temperature). For a horizontal wellbore drilled in the direction of minimum horizontal stress, the minimum tangential stress around the wellbore is now given by Equation (3):

$$\sigma_{\theta\theta} = S_{Hmax} + S_V - 2(S_{Hmax} + S_V)\cos(2\theta) - 2P_{pore} - P_{wellbore} + \Delta\sigma_{\theta\theta}^{\Delta T} \quad (3)$$

Cooling of the wellbore (*i.e.*, negative values of ΔT and $\Delta\sigma_{\theta\theta}^{\Delta T}$) reduces the value of the tangential stress $\sigma_{\theta\theta}$ around the wellbore, thus lowering the threshold for placing the wellbore in a state of effective tension and lowering the threshold for hydraulic fracture initiation. It will also lower the value of S_{hmin} , the minimum horizontal stress. For a rock that is effectively cooled, this will reduce the fracture propagation pressure. The fact that cooling leads to reduction of fracture initiation and propagation pressure is well-known from deepwater drilling operation, where circulating cold drilling fluid across downhole formations triggers induced tensile wellbore fracturing and associated mud losses, see *e.g.*, (Gonzalez et al., 2004; Algu et al., 2007; Hettema et al., 2018).

2.3. Thermal Cracks

The beneficial effect of cooling for hydraulic fracturing may not be limited to fracture initiation and propagation pressure reduction. Cooling may also induce a large number of small thermal cracks perpendicular to a hydraulic fracture. Figure 1 shows thermal cracks of depth d perpendicular to a hydraulic fracture in a horizontal wellbore in a tight formation such as a shale. Hydraulic fractures tend to grow normal to the minimum horizontal stress, S_{hmin} . When cold fluid is injected into a fracture, heat diffusion will cool the fracture surfaces, cooling down the zone directly neighboring the fracture. The confined rock will now shrink parallel to the hydraulic fracture length, causing thermal cracks to occur with depth d along the x -axis, with spacing distance b , and width t_f .

Figure 1 shows that these thermal cracks will have to open against the maximum in-situ horizontal stress S_{Hmax} . These thermal cracks therefore generally do not extend too far from the hydraulic fracture face. Hence, we will approximate them as straight fractures. Moreover, we will assume that their presence does not influence heat transfer in the x -direction.

Figure 1: Thermal fractures created perpendicular to a hydraulic fracture.

Thermal fracturing studies on ceramic and glass by H.A. Bahr (1986); Bahr et al. (2010) indicate that the average spacing of a thermal crack is expected to be roughly proportional to its length, *i.e.*, $b \propto d$. For illustration purposes, Figure 2.a shows the thermal shock crack pattern on a glass ceramic slab. Faces A and C were quenched at $\Delta T = 300K$ in water and face B was kept thermally isolated. The two faces A and B serve as boundary conditions and heat transfer through the interfaces between face B and the other two faces create thermal cracks. It can be observed that the length of cracks d and their spacing b are roughly proportional, *i.e.*, the smaller the cracks, the shorter apart they are and the larger the cracks, the further apart they are (Figure 2.b). We make use of this observation to estimate values of b and t for thermal cracks in shale. This proportionality of fracture length and spacing is called self-similarity. A self-similar object is the object which approximately or exactly follows part of its pattern. Many experimental results including the research conducted by Bahr et al. (2010); Bahr and Weiss (1986) as shown in Figure 3 confirm that the length of thermal crack growth from a half space such as fractures created on the walls of a hydraulic fracture is an example of self-similarity (Allain and Limat, 1995; Boeck et al., 1999; Hull and Caddock, 1999; Dufresne et al., 2003). In other words, the length of thermal cracks due to thermally induced rock contraction is proportional to the distance between the two consecutive fractures. Tarasovs and Ghassemi (2014a) studied the propagation and interaction of an initial array of 100-200 small cracks of length d and spacing b . They applied the thermal load at the faces of the cracks. Using simulation, they showed that when some of the initial cracks stop after several crack increments, the resulting crack pattern does not depend on the initial geometry, and that crack length versus spacing follows a power-law scaling.

The material properties reported for ceramic tested by Bahr et al. (2010) are: Fracture toughness,

175 $K_{IC} = 1.89 \text{ MPa}\sqrt{\text{m}}$; coefficient of thermal expansion, $\alpha = 1.15 \times 10^{-5} \text{ K}^{-1}$; and Young's modulus, $E = 60 \text{ GPa}$. The characteristic length scale of such thermal cracks induced by thermal shock is discussed by Tarasovs and Ghassemi (2014b). Note that these properties compare well with those of stiff shales; hence, we expect to see a similar pattern of thermal cracks in such shales.

Figure 2: Thermal shock crack pattern on a glass ceramic slab (Bahr et al. (2010)). (a) Faces *A* and *C* were quenched at $\Delta T = 300 \text{ K}$ in water while faces *B* were kept thermally isolated, (b) self-similarity of crack length and spacing.

To get an insight into the efficiency of thermal crack creation during hydraulic fracturing, we numerically solve the 1D heat conduction equation in a semi-infinite solid medium shown in Figure 3. 180 The results are then compared to an analytical heat diffusion solution. We assume that the diffusion of heat from the reservoir rock to the cold fracturing fluid is conducted along the x axis, and that the fracture side (half-space) is an infinite medium.

Figure 3: Thermal fracture front changes with time along x axis.

The closed-form solution of the problem shown in Figure 3, is given by Incropera and DeWitt
 185 (1990) as:

$$\frac{T(x, t) - T_s}{T_i - T_s} = \text{erf}\left(\frac{x}{2\sqrt{Dt}}\right) \quad (4)$$

Where “erf” in Equation (4) is the error function defined as:

$$\text{erf}(u) = \frac{2}{\sqrt{\pi}} \int_0^u \exp(-t^2) dt \quad (5)$$

Table 1 lists the properties used for both analytical and numerical simulations.

Parameter	Units
Young's Modulus, E	50 GPa
Thermal expansion coefficient, α	$1 \times 10^{-5} \text{ K}^{-1}$
Poisson's ratio, ν	0.22
Minimum horizontal stress, S_{hmin}	2000 psi
Maximum horizontal stress, S_{Hmax}	3000 psi
Reservoir temperature, T_i	125°C
Fracturing fluid temperature, T_s	30°C
Thermal conductivity, k	$2 \frac{\text{W}}{\text{mK}}$
Mass density of rock, ρ	$2300 \frac{\text{kg}}{\text{m}^3}$
Specific heat, C	$1380 \frac{\text{J}}{\text{kgK}}$
Thermal diffusivity, D	$^{a}0.63 \times 10^{-6} \text{ m}^2/\text{s}$
Simulation time	1 day

Table 1: Material properties and external parameters used for the solution of the thermal crack development problem described in the text.

^aThermal diffusivity is calculated as: $D = k/(\rho C)$

190 The distribution of temperature along the x direction as a function of time is shown in Figure 5. It can be seen that the initial temperature in the rock is equal to the reservoir temperature T_i . As the time goes on, temperature decreases and the rock cools down. The temperature at the hydraulic fracture wall is kept at a constant value of T_s . In order for the thermal cracks to initiate, the reservoir rock has to undergo a sufficient amount of contraction. Knowing that the thermal cracks open against the maximum in-situ stress S_{Hmax} ,
195 we will first have to determine the critical temperature change ΔT_c for cracks to initiate, as follows.

The thermal strain is proportional to the coefficient of thermal expansion and the change of temperature, i.e.,

$$\varepsilon_{thermal} = \alpha \Delta T \quad (6)$$

The deformation of shale is assumed to be linear elastic and the failure is assumed to be brittle. The
200 component of the normal stress in a linearly elastic material is calculated as:

$$\sigma_{thermal} = E \varepsilon_{thermal} = E \alpha \Delta T \quad (7)$$

The thermal stress at any point x in our 1D semi-infinite heat conduction problem is then given by:

$$\sigma(x, t) = E\alpha[T_i - T(x, t)] \quad (8)$$

Equation (8) is written for a plane stress condition. For a plane strain condition, it should be modified to become:

$$\sigma(x, t) = E(1 + \nu)\alpha[T_i - T(x, t)] \quad (9)$$

When the stress in Equation (9) exceeds the maximum in-situ stress S_{Hmax} , thermal cracks will develop. Therefore, we can write the following condition for the initiation of thermal cracks in a plane strain approx-
 205 imation:

$$E(1 + \nu)\alpha[T_i - T(x, t)] \geq S_{Hmax} \quad (10)$$

and the critical temperature used for cooling down and initiation of thermal cracks, which is equal to $T_i - T(x, t)$, can be calculated as

$$\Delta T_c \geq \frac{S_{Hmax}}{E(1 + \nu)\alpha} \quad (11)$$

It can be seen from Equation (11) and graphically in Figure 4 that the critical temperature reduction is proportional to the in-situ stress, *i.e.*, reservoirs at larger true vertical depth will be harder to thermally
 210 fracture. Also, the critical temperature reduction is inversely proportional to the Young's modulus of rock. In other words, the stiffer the rock, the easier it is to fracture it by a thermal shock. We use a range of 5 to 100 GPa for Young's modulus of shales and calculate the critical temperature reduction for various in-situ stresses ranging from 50 to 3000 psi. Poisson's ratio is taken to be 0.25 and the thermal expansion coefficient is taken $1 \times 10^{-5} \frac{1}{^\circ K}$. We can observe that for less stiff shales with Young's modulus of about 5 GPa, a
 215 considerable reduction of temperature is required to reverse the effect of compressive stress and fail the rock in tension. Stiff shales, on the other hand, require only modest temperature reduction, as expected.

Figure 4: The impact of Young's modulus and in-Situ stress on critical temperature reduction required to initiate thermal fractures.

The critical cool down temperature ΔT_c is also shown in Figure 5. For the case described in Table 1, its critical cooling value is around 35 degrees Celsius. As the cooling front moves out into the rock formation over time, this critical cool down temperature is reached at locations that are progressively deeper into the rock formation, extending the thermal crack. Note that these cracks not only create additional permeability, but could themselves serve either as fracture initiation points or seeds to better link up the induced hydraulic fracture with in-situ natural fracture networks.

Figure 5: Distribution of temperature in 1D along the x -direction as a function of temperature.

The length of a thermal crack plays a significant role in calculation of the stress intensity factor K_I . To evaluate the extension of thermal fractures with time, we manipulate Equation (4) to obtain the following expression for $T_i - T(x, t)$ as:

$$T_i - T(x, t) = \left[(T_i - T_s) \operatorname{erfc} \left(\frac{x}{2\sqrt{Dt}} \right) \right] \quad (12)$$

The function “erfc” in Equation (12), is the complementary error function and is defined as:

$$\operatorname{erfc}(u) = 1 - \operatorname{erf}(u) = \frac{2}{\sqrt{\pi}} \int_u^{\infty} \exp(-t^2) dt \quad (13)$$

Inserting $[T_i - T(x, t)]$ from Equation (12) into Equation (10) and changing the inequality sign to the equality sign for the onset of crack initiation, we obtain:

$$E(1 + \nu)\alpha \left[(T_i - T_s) \operatorname{erfc} \left(\frac{d}{2\sqrt{Dt}} \right) \right] = S_{Hmax} \quad (14)$$

Note that x , the coordinate of crack tip is replaced with d , the thermal crack length. Solving Equation (14) for d , we obtain:

$$d = (2\sqrt{Dt}) \operatorname{erfc}^{-1} \left[\frac{S_{Hmax}}{E(1 + \nu)\alpha(T_i - T_s)} \right] \quad (15)$$

2.4. Effect of Pore Pressure

Finally, we consider the influence of pore pressure. Volumetric rock stimulation can be achieved through pore pressure increase. Increasing pore pressure is an efficient way to break the rock matrix bonds by reduc-

ing effective stresses and triggering local tensile stress failure. This method works best for highly permeable rocks such as sandstones, in which pore pressure can be quickly raised. For impermeable rocks such as shale, however, pore pressure diffusion is slow; in fact, it is slower than thermal diffusion. Therefore, it is not easy to break such impermeable rocks by pore pressure increase. Note that the tensile failure achieved in hydraulic fracturing is achieved by applying pressure as an external tensile load, not an internal pore pressure load leading to tensile stresses in the rock matrix. The inability to induce tensile stresses in a timely manner in tight shale formation by pore pressure increase leads us to explore other possibilities to induce tensile failure, such as offered by cooling / freezing of the rock. Note that in the following analyses, we have not yet considered the secondary effects of temperature directly on pore pressure; this will have to be addressed in future work.

3. Modeling Approach

3.1. Validation: Heat Diffusion at Fracture Wall

To investigate the effect of heat diffusion at the fracture wall and validate our simulation results, we first solve a 1-D heat diffusion problem numerically and compare the result with an analytical solution. Our validation model is a 2-D geometry of a 10 m by 3 m rectangle with a small notch created on the lower side of the rectangular domain to represent the hydraulic fracture wall. The geometry, mesh, and the contour plot of temperature distribution are shown in Figure 6. For accurate results of heat flux in the vicinity of the fracture wall, a high density mesh is created along the fracture geometry. The initial temperature of reservoir rock is set at 125°C and the imposed temperature boundary at the fracture wall is 30°C. We perform a transient coupled analysis to study the temporal variation of heat diffusion and heat flux in the domain. Since the deformation along the x-direction does not affect the heat diffusion in that direction, the boundaries for the force equilibrium equation are fixed. It can be seen in Figure 6 that the rock cools down gradually as we go farther away from the face of the hydraulic fracture. To study quantitatively how much rock volume is affected by thermal shock, we need to find the depth at which temperature has decreased by the critical value ΔT_c . The calculation of impacted depth is presented in Figure 5, where it is shown that the coordinate x at the intersection of the temperature profiles and the horizontal dashed line is the locus of points where the temperature has dropped by $T_i - \Delta T_c$.

Figure 6: The numerical solution of rock fracture cool down and temperature distribution.

To validate the numerical model, we first compare the numerical result with the closed-form analytical solution we derived in Equation (12). It can be seen in Figure 7 that numerical simulation of this coupled heat transfer process in rock is in good agreement with the analytical or closed-form solution.

Figure 7: The comparison between analytical (Equation (4), Incropera and DeWitt (1990)) and Finite Element solution of temperature distribution in 1D.

Figure 8a shows the temperature distribution normal to fracture wall for a simulation time of one day. It can be observed that thermal cooling is effective within 2 feet (0.6 m) away from fracture wall. It should be noted that the jump of temperature (also known as temperature overshoot) at initial stages is an artifact of numerical method and can not be eliminated. Figure 8b shows the heat flux distribution normal to the

fracture wall. It can be seen that heat flux initially starts at a high value of 1400 W/m^2 and quickly reduces over time. This high value at the initiation of the rock cooling process highlights the initial thermal shock impact.

Figure 8: (a) Temperature distribution normal to fracture wall, (b) heat flux distribution normal to fracture wall.

Now that the numerical model is validated and the temperature and heat flux evolutions over time are studied, we can extend our simulation to the case of a wellbore temperature reduction and study the impact of thermal load on tensile and shear stresses in the near-wellbore zone.

3.2. Wellbore Model Description

Figure 9 shows the 3D finite element model used to study the problem of heat transfer in a horizontal wellbore. The wellbore radius in this case is 6 inches and the reservoir domain is a rectangular block of rock 200 ft × 200 ft × 1000 ft. Initial reservoir conditions of 1000 psi pressure and 100°C temperature are used. To eliminate the effect of boundaries, the well is placed at the center of a 200 ft by 200 ft rock volume, as shown in Figure 9b. The model domain is fixed on the block surfaces normal to the wellbore surface. Using the boundary condition we have imposed, the wellbore is able to deform radially in response to thermal and mechanical loads. We perform a multi-step fully coupled TM analysis. In the first step of the simulation, the initial conditions, including initial formation pressure and temperature, are activated. In the second step, a constant temperature of 0°C is applied to wellbore internal surface, *i.e.*, a differential temperature of 100°C is applied between the wellbore and formation. This generates the heat flux from the reservoir toward the low-temperature wellbore surface. Since the rock is confined externally, it will not be able to deform freely under this heat transfer process; hence, thermal stress gradients develop in the rock, leading to tensile cracks.

Figure 9: Finite element model description for heat transfer analysis.

3.3. Quantifying the zone of effective cooling

The problem of heat transfer and tensile stress generation by cooling/ freezing of the rock is a coupled TM problem. This problem requires solving the following set of coupled equations:

1. Equilibrium of forces:

$$-\nabla \cdot \sigma = F \quad (16)$$

where F is the external force and σ is the total stress tensor. For elastic analysis, the effect of temperature T as the coupling term in TM analysis can be expressed using Equation (17).

$$\sigma = D\epsilon = D(\epsilon - \epsilon_{th}) = D(\epsilon - \alpha(T - T_{ref})) \quad (17)$$

where D is the elastic rigidity, ϵ is the mechanical strain, ϵ_{th} is the thermal strain, α is the coefficient of thermal expansion, and T_{ref} is the reference temperature.

2. Heat transfer equation: In the absence of convection and source term, the heat transfer equation can be expressed as:

$$\rho C_p \frac{\partial T}{\partial t} = \nabla \cdot (k \nabla T) \quad (18)$$

For the reservoir thermal simulation, the parameters listed in Table 2 are used to quantify the extent of the cooling zone around the wellbore.

Parameter	English units	SI units
Reservoir properties		
Mass density of rock, ρ	0.08 $\frac{\text{lbm}}{\text{in}^3}$	2300 $\frac{\text{kg}}{\text{m}^3}$
Shale mechanical properties		
Modulus of elasticity, E	15×10^6 psi	100 GPa
Poisson's ratio, ν	0.3	0.3
Thermal expansion, β	$9.7 \times 10^{-6} \frac{1}{^\circ\text{K}}$	$9.7 \times 10^{-6} \frac{1}{^\circ\text{K}}$
Shale thermal properties		
Conductivity, k	0.45 $\frac{\text{lb f in}}{\text{s in } ^\circ\text{K}}$	2 $\frac{\text{W}}{\text{m } ^\circ\text{K}}$
Specific heat, C	5,500 $\frac{\text{lb f in}}{\text{lbm } ^\circ\text{K}}$	1380 $\frac{\text{J}}{\text{kg } ^\circ\text{K}}$
Fluid properties		
Hydraulic conductivity, K	$39 \times 10^{-14} \frac{\text{in}}{\text{s}}$	$1 \times 10^{-14} \frac{\text{m}}{\text{s}}$
Void ratio, e	1	1
Specific weight, ρg	0.04 $\frac{\text{lb f}}{\text{in}^3}$	9,806 $\frac{\text{N}}{\text{m}^3}$

Table 2: Model properties for 3-D coupled TM analysis.

The temperature distribution for three instances of time (at initial stage, 1800 sec and 7200 sec) are

shown in Figure 10.a. As described earlier, due to the large heat flux at the start of cooling operation, a major portion of the heat energy is transferred quickly from the hot reservoir rock to the cold wellbore zone. This slows down after about 30 minutes to one hour. To withdraw more heat energy from the reservoir, cold fluid must be injected for longer periods of time. The affected cooling zone for the condition of material properties used in the case shown is one foot from the wellbore; however, the extent of this zone depends on the thermal conductivity of the rock. Note that this result was obtained for a lowest possible value for thermal conductivity as a worst case scenario. For higher thermal conductivities, the cooling zone becomes extended for the same cooling conditions. This is studied in further detail in the sensitivity analysis section of this paper. Figure 10.b shows that significant tensile stresses (radial tensile stress around the wellbore) develop in response to the induced cooling / freezing effects. Tension in Figure 10.b is reflected by positive stress values and compression is reflected by negative values. The results demonstrate that even if a large zone of reservoir remains under compressive in-situ stress, the near-wellbore zone experiences significant tensile stresses.

Figure 10: a) Temperature distribution around the wellbore after $t = 0$, 1800, and 7200 seconds, b) Stress distribution around the wellbore after $t = 0$, 1800, and 7200 seconds.

Due to cooling of the wellbore wall and the existence of rock lateral constraints, the reservoir rock in the near-wellbore zone contracts and the wellbore continues to “bulge out” toward the reservoir. Figure 11 shows this deformation of the wellbore surface, which results in creation of radial tensile stresses in rock and the development of thermal cracks.

Figure 11: Displacement vectors of wellbore wall in radial direction.

The analysis shown in Figure 11 was continued for longer simulation times to delineate the continued expansion of the efficient cooling zone around the wellbore. The temperature distribution in the radial direction with respect to the wellbore wall for 3 and 24 hours of analysis are plotted in Figure 12. The cooling zone extends to approximately 2 feet after 3 hours and then extends to 6 feet after 24 hours. In field practice, however, such long cooling periods may prove to be impractical and uneconomical, and other methods such as chemical manipulation of the fracturing fluid to generate an in-situ endothermic reaction with a cooling effect may have to be incorporated (van Oort et al., 2018).

Figure 12: Variation of temperature in the radial direction around the wellbore for a longer simulation time of 24 hours.

3.4. Heterogeneity Impact on Production

Shales are mostly inorganic materials and inherently mechanically anisotropic, resulting in complexities that must be accounted for in numerical simulation of the rock fracturing process. Therefore, the thermo-hydro-mechanical (THM) properties of shale including Young's modulus of elasticity, compressive and tensile strength, and permeability are primarily dependent on 1) heterogeneity and mineral composition of the rock, 2) spatial distribution of organic/inorganic constituents (Gao et al., 2015) and 3) spatial distribution of in-situ fractures in shale. Clay minerals in shale enhance plastic deformations, which in turn reduces the brittleness of rock. Silica, on the other hand, increases the brittleness of rock and facilitates fracturing. Jia et al. (2018) have performed numerical and experimental investigation of permeability in heterogeneous fractured tight porous media. They performed gas flow through shale core plugs for several types of gas and investigated the complex relationships between adsorption and permeability over a wide range of pressure. Jia et al. (2017) also studied core plug heterogeneity effect on the flow behavior by flowing gas through core plugs and numerically modeled the effect of horizontal and vertical bedding of decreasing/increasing permeability value on pressure decline over time. He modeled the extent of heterogeneity using a Dykstra-Parsons coefficient (V_{dp}) ranging from 0.4 to 0.9 and concluded that the effective permeability ratio reduces to 11% and 18% with the Dykstra-Parsons coefficient of 0.69 as determined from transient and steady state method. Authors have focused on heterogeneity of strength and thermal properties in this paper. Our sensitivity analysis results in this paper show that rock fracturing is facilitated due to heterogeneity (Figure 17). In conclusion, heterogeneity reduces permeability, but facilitates fracturing and promotes connectivity of thermal fractures to in-situ fractures which enhances flow in porous media (Enayatpour et al., 2018).

3.5. Sensitivity Analysis of Rock Variability Parameters

In spite of all the complexities associated with distribution of material properties, fracture creation in shales benefits from stresses induced by disparate material properties such as variation in Young's modulus E , coefficient of thermal expansion α , specific heat C and thermal conductivity k between two neighboring rock layers. Due to compatibility of strains in a continuous medium, the adjacent layers of rock of different stiffness or thermal expansion coefficient will be subjected to similar strains, but different stresses. This anisotropy-induced stress plays a significant role in the success of thermal fracturing in tight formations. To investigate the macro-scale effect of thermal loading (here, cooling down the rock) on anisotropy-induced stress development, a finite element-based numerical model was created and deformation, shear stresses and tensile stress at the rock layers interface were studied.

Figure 13 is the layout of problem geometry and the work-flow of our simulations. Figure 13.a shows two rock blocks representing the two rock layers of different Young's modulus E , coefficient of thermal expansion α , specific heat C and thermal conductivity k . The lateral constraint of rock is modeled using fixed supports at the two ends of the rock blocks. The process of cooling down the hot reservoir rock from 100°C to 0°C is performed using injection of a cold fracturing fluid. This is simulated by the thermal boundary conditions imposed laterally to the external surfaces of the two rock layers representing hydraulic or in-situ

fracture walls (Figure 13.b). As a result of heat loss from rock to cold fracturing fluid, the two rock layers contract laterally and undergo a thermal strain of magnitude $\alpha\Delta T$. Due to different values for α , the top layer in Figure 13.c exhibits twice as large a thermal strain as the bottom layer. This is reflected by the total deformation vector plot in Figure 14.a and leads to 1) thermally induced shear stress at the interface, Figure 14.c and 2) an interface separation in tangential direction, Figure 14.d.

The different induced thermal strains of the two blocks leads to sliding and tensile failures at the rock interface, which in turn enhances the rock permeability. The shear and tensile stress effects at the interface between the two layers are shown in Figure 14 (d and e), with shale parameters obtained from literature (Horsrud et al. (1998); Ibanez and Kronenberg (1993); Ibanez (1993); Al-Bazali et al. (2008)). The Young's Modulus E ranges from 5 GPa (Hiroki, 2012) for soft shales (note that Josh et al. (2012) report a lower value of 1-3 GPa) up to 100 GPa (Zoback, 2007; Lau and Yu, 2013) for very stiff shales. The parameters used in our simulation for rock sensitivity analysis are listed in Table 3.

Parameter	Values (SI units)
Upper block, thermal/mechanical rock properties	
Mass density of rock, ρ	2300 $\frac{\text{kg}}{\text{m}^3}$
Thermal conductivity, k	0.5, 1, 2 $\frac{\text{W}}{\text{mK}}$
Specific heat, C	1300, 1350, 1400 $\frac{\text{J}}{\text{kgK}}$
Modulus of elasticity, E	10, 50, 100 GPa
Poisson's ratio, ν	0.25, 0.3
Thermal expansion, α	$<1.2, 1.5, 5, 10> \times 10^{-6} \frac{1}{\text{K}}$
Initial temperature, T_1	100 °C
Final temperature, T_2	$<0, 20, 40, 60, 80, 100> \text{°C}$
Lower block, thermal/mechanical rock properties	
Mass density of rock, ρ	2300 $\frac{\text{kg}}{\text{m}^3}$
Thermal conductivity, k	1 $\frac{\text{W}}{\text{m}^\circ\text{K}}$
Specific heat, C	1350 $\frac{\text{J}}{\text{kg}^\circ\text{K}}$
Modulus of elasticity, E	10 GPa
Poisson's ratio, ν	0.25
Thermal expansion, α	$1.2 \times 10^{-6} \frac{1}{\text{K}}$
Initial temperature, T_1	100 °C
Final temperature, T_2	$<0, 20, 40, 60, 80, 100> \text{°C}$

Table 3: TM properties of the rock blocks for sensitivity analysis study.

The presence of organic and inorganic constituents in shale causes the material properties to exhibit a wide range of variation, as mentioned earlier. To account for this, a wider range of specific heat, thermal conductivity, Young's modulus of elasticity and thermal expansion coefficient values is used to simulate the relevant properties of the upper rock block, as listed in Table 3, while the properties of the lower block are kept constant. Various combinations of simulation cases are modeled and shear and tensile stress variations are studied. The result of this sensitivity analysis is shown as a response surface plot, (Figure 13.f). The mathematical formulation and discussion of response surface analysis are provided in the next section.

Figure 13: (a) Numerical model setup of thermally induced stress and deformation for two layers of rock with different thermal and mechanical material properties, (b) cooling down the rock at the boundaries, (c) heat flux vectors through rock boundaries, (d) shear stress induced at the interface, (e) tensile stress induced at the interface and (f) response surface of combinations of input variations.

3.6. Sensitivity Analysis Results Discussion

Figure 14 shows the coupled TM simulation results of thermally induced stress and deformation for a model of two-layered rock with different thermal and mechanical material properties. It can be seen in vector plots of Figure 14a and b that due to temperature reduction, the upper block exhibits larger contraction with a maximum of 0.34 mm displacement at the corners. This results in shear stress development at the interface, as shown in Figure 14c, leading to sliding between the two rock layers (Figure 14d).

Figure 14: Coupled TM simulation results of thermally induced stress and deformation for a model of two-layered rock with different thermal and mechanical material properties. (a) 3D deformation vector plot, (b) top-view deformation vector plot, (c) shear stress at the interface of the two rock layers induced by differential lateral contraction of rock layers, (d) interface sliding separation due to excessive shear stress.

Before we discuss the simulation cases in a single response surface plot, let us look at the lateral contraction and interfacial tensile stress versus temperature gradients varying from 0 °C to 100 °C, for three stiffness ratios E_2/E_1 of 1, 5 and 10 to highlight the power of a TM response surface plot. Figure 15 shows the lateral displacement or contraction of rock for five temperature reduction values of 20, 40, 60, 80 and 100 °C respectively when the original reservoir rock temperature is set at 100 °C. The maximum contraction or possibility of rock shear failure occurs at a temperature gradient of 100 °C and a rock stiffness ratio of 10. This result is in agreement with Equation (11) and confirms that brittle rocks are more prone to thermal

failure.

Figure 15: Variation of reservoir rock lateral contraction under temperature reduction values of 0 °C to 100 °C for various stiffness ratios of 1, 5 and 10.

Figure 16 shows the variation of the interfacial tensile stress of rock due to cooling down the rock at five temperature reduction values of 20, 40, 60, 80 and 100 °C. The fixed boundary condition (*i.e.*, no displacement boundary condition) is used in all cases at the top/bottom of the model. Similar to the previous plot, the stiffness ratio values are 1, 5 and 10. The plot of Figure 16 demonstrates the ease of tensile fracturing in shale as a result of cooling down the reservoir rock.

Figure 16: Variation of tensile stress normal to shale layers interface under temperature reduction values of 0 °C to 100 °C for various stiffness ratios of 1, 5 and 10.

The results shown in Figures 15 and 16 appear to be linear with respect to rock stiffness variations. In general, this is not always the case due to the complex interplay between rock toughness and temperature reduction level. In addition, this highlights the necessity of a response surface study whereby a more complicated non-linear multi-dimensional input/output relation is constructed when all inputs vary simultaneously.

Figure 17 shows the variation of tensile force at the interface when all parameters including Young's modulus E , coefficient of thermal expansion α , specific heat C and thermal conductivity k , vary at the same time. Since it is not possible to show more than two inputs on the RS plot, we have limited are presentation of results to maximum two inputs of highest correlation factors. These are: 1) the Young's modulus E and 2) the temperature gradient ΔT . The two horizontal axes reflect temperature gradient and the upper block rock stiffness (when the stiffness of the lower block is maintained at 10 GPa). The surface plot shows the sensitivity of the result (here, tensile force) with respect to changes of all input parameters. It can be seen that at all values of rock stiffness ratio, the response of tensile force to temperature reduction is linear. However, at a given temperature gradient, the response of tensile force to changes of stiffness ratio is nonlinear as shown in Figure 17. Calculating the maximum tensile stress of rock due to the force of 2.4×10^5 N (54,000 lbf) from sensitivity analysis, over the 1 ft by 1 ft rock interface area, we obtain a tensile stress of 2.6×10^6 Pa (375 psi). The results presented in Figures 16 and 17 show that the tensile stresses developed during the cooling process are one to two orders of magnitude larger than the tensile strength of shale (*i.e.*,

2.76×10^4 Pa (4 psi) normal to the bedding plane or layers interface Gao et al. (2015)) and reflects the potential and relative ease of shale thermal fracturing.

Figure 17: Response surface plot of tensile force normal to shale layers interface when all parameters including Young's modulus E , coefficient of thermal expansion α , specific heat C and thermal conductivity k , vary simultaneously.

4. Permeability Estimate

The most important parameter in porous media flow simulation is permeability. Estimates of permeability using analytical methods rely on fracture opening; however, many complexities including: in-situ stress, crack geometry, rock grain size and lithology, tortuosity, and fracture surface damage affect the field value of permeability. There have been a number of experimental investigations into the effect of parameters such as grain size and in-situ stress on permeability. Chen et al. (2000) showed that fracture permeability is enhanced by shear dilation as a result of shear displacement, even at high normal stress values. Recent observation of samples taken from previously stimulated rock volumes of the Eagle Ford shale following hydraulic stimulation shows the existence of a great number of open but un-propped fractures, (Rateman et al., 2017). As studied by Chen et al. (2000), proppant-free hydraulic fractures can greatly enhance permeability

in tight formations. Creation of small gaps in tight formations has a significant impact on the conductivity of such formations to gas flow in particular. The values of gaps we have previously obtained from CZM simulations indicate that thermal fracturing has the potential to meaningfully improve the recovery in tight formations (Enayatpour et al., 2018). The existence of open un-propped fractures as shown by Raterman et al. (2017) increases the significance of thermal fractures because they can stay open and contribute to permeability enhancement even when remaining un-propped.

Accurate rock permeability measurement requires field or laboratory measurements. In the absence of these, a simple analytical calculation of thermally induced fracturing is used to show the efficiency of thermal fracturing. Figure 18 shows a configuration of two perpendicular thermal fractures in a block of rock with dimensions 1ft×1ft×1ft. Based on our simulation data and results, the permeability of reservoir rock is taken as 1μD and the width of fracture as 0.3 mm. The permeability of a fracture of width w, is $\frac{w^2}{12}$ or 7500 D, in this case. Total area of fractures for flow in the y direction is 180 mm². Given the area and permeability of fractures and reservoir rock in the y direction and using Equation (19), the stimulated permeability in the y direction is calculated to be 15×10⁶ μD.

$$K_y = \frac{\sum K_i A_i}{\sum A_i} \quad (19)$$

In the x direction, the calculation of permeability is performed in two steps. First, Equation (19) is used to obtain permeability of the three parallel layers in the x direction, and then Equation (20) is used to calculate the total permeability in the x direction.

$$K_x = \frac{\sum L_i}{\sum \frac{L_i}{K_i}} \quad (20)$$

L in this equation is the length of the cube in the x direction. Permeability in x or z directions is then obtained to be 7.5×10⁶ μD. Obtaining stimulated permeability of the given cube demonstrates the efficiency of thermal fracturing whereby the reservoir permeability of 1 μD is enhanced by 6 orders of magnitude. For our hydrocarbon recovery enhancement simulation we have assumed a more conservative value of up to 4 orders of magnitude larger than that of reservoir rock and used a maximum permeability of 10⁴ μD.

Figure 18: Analytical model to obtain the effective permeability of a block or reservoir rock and two perpendicular thermal fractures.

5. Results & Discussion

We studied different components of rock thermal fracturing analytically and numerically. For various numerical simulations including stress-deformation, heat transfer and hydrocarbon flow in porous media, we have utilized three Finite Element commercial packages: ANSYS, ABAQUS and COMSOL. We are now looking at the effect of induced thermal cracks on the recovery of natural gas from a fractured horizontal well. Figure 19 shows the geometry of the shale reservoir under study, with the finite element discretization of the three domains: 1) the wellbore, 2) the hydraulic fracture, and 3) the thermally stimulated zone that was considered in the gas flow simulation. Unlike the Finite Difference Method (FDM) which discretizes the derivatives of the state variable, discretization of the reservoir domain in the Finite Element Method is conducted by creating meshing and using shape functions to connect the nodal solution to solutions at any other point within the elements. To obtain accurate results, a high density mesh (36000 nodes, 17500 triangular high-order elements) is used in the fracture zone and the near wellbore region. About 15400 of the elements are concentrated in the near wellbore zone to accurately calculate pressure gradients in the vicinity of the wellbore. To add a flow component to the above set of coupled equations of stress-heat transfer (Equations 16-18), we first solve the stress-heat transfer problem, obtain the zone of thermal crack extensions around the wellbore, and with the permeability estimate described earlier solve the pressure diffusivity equation (21). For the simulations presented here, we have assumed four levels of permeability enhancement of 10, 100, 1000, 10000 μD for the stimulated zone around the wellbore with the rock permeability of 1 μD . Due to the very low permeability of tight rock formations, even a narrow thermal fracture will enhance the permeability by orders of magnitude: assuming a maximum improvement of permeability by four orders of magnitude from 1 μD to 10000 μD is therefore not unreasonable, as discussed previously. Assuming permeability enhancement is induced by thermal fracturing, Equation (21) is solved for the flow problem of a wellbore with radial rock stimulation. The following equation is used by the COMSOL commercial Finite

Element software and its derivation is shown in Appendix A. Notice that this equation takes into account the effect of high order pressure gradients to solve the nonlinear diffusivity equation.

$$\phi c_t \frac{\mu}{k} \frac{\partial p}{\partial t} = \nabla^2 p + c_{\text{fluid}} (\nabla p \cdot \nabla p) \quad (21)$$

There are a number of phenomena contributing to gas flow in shale matrix micro- to nano-scale pore network. These are: no-slip and slip flow, Knudsen diffusion, surface diffusion and Langmuir desorption.

Extensive research shows that these phenomena affect apparent permeability and make the shale flow calculation a complex multi-scale problem (Shabro et al., 2011; Islam and Patzek, 2014; Javadpour et al., 2007; Chen et al., 2017; Zhang et al., 2015). Our focus in this research is recovery improvement associated with permeability enhancement due to macro-scale thermal crack stimulation while micro- and nano-scale gas flow is not yet taken into account. Incorporating these complex features requires a separate research effort and is beyond the objective of this paper. To see a workflow of hydraulic fracture impact on well production in composite shale formation system, readers are referred to the work by Yuan et al. (2018)

Figure 20 shows the improvement in total production as a result of thermal stimulation around the wellbore. Evidently, without a hydraulic fracture, there is no significant hydrocarbon production. However, once we have generated a hydraulic fracture, it can be observed that the creation of thermal cracks in a 4 ft radius around the wellbore improves hydrocarbon recovery from the hydraulic fracture by a non-trivial 16%. It should be noted that hydrocarbon recovery obtained here varies as a function of reservoir and fluid properties. For our simulation we have used methane gas (critical temperature: -82.3°C , critical pressure: 45.79 atm and fluid compressibility: $1.5 \times 10^{-7} \frac{1}{\text{Pa}}$). The fluid density is obtained as a function of temperature (i.e., real gas condition) and plugged into COMSOL. Other properties are listed in Table 4.

Parameter	Field units
Reservoir properties	
Size	200×200 ft^2
Fracture half-length, X_f	50 ft
Fracture width, w_f	0.5 in
Boundary pressure, P_e	5000 psi
Well pressure, P_i	2000 psi
Radius of damage zone, r_d	varies between 1 and 4 ft
Wellbore radius, r_w	3 in
Rock properties	
Formation permeability, $k_{\text{formation}}$	1 μD
Formation porosity, ϕ	0.14
Fracture permeability, k_{frac}	1,000 μD
Stimulated zone permeability, k_d	10, 100, 1000, 10000 μD
Fluid properties	
Dynamic viscosity, μ	0.02 cp
Compressibility, c_f	10^{-3} psi^{-1} ($1.5 \times 10^{-7} \frac{1}{\text{pa}}$)
Density (Ideal Gas), ρ	$10^{-5} \times \text{pressure}^a$
Density (Real Gas), ρ	$10^{-5} \times \text{pressure}/Z(p)^b$

^aPressure in Pa and the density in ($\frac{\text{kg}}{\text{m}^3}$)

^bEquation (23)

Table 4: Input parameters of the numerical production model.

480 .Figure 21 shows the impact of the permeability of the thermally stimulated zone in recovery improvement.

Figure 19: Geometry of reservoir and finite elements discretization of the three domains used to simulate the gas flow.

Figure 20: Improvement in total production as a result of thermal stimulation around the wellbore.

Figure 21: Improvement in total production as a result of thermal stimulation around the wellbore for various levels of permeability enhancement.

Another example showing the benefit of augmentation of hydraulic fracture stimulation by induced cooling is shown in Figure 22. We have simulated gas flow in a fractured horizontal well placed in a low permeability formation. The hydraulic fractures are further stimulated by thermal shocks induced by the injection of a cold fracturing fluid. Initially many small thermal cracks are created, however only a few of them can grow far away from the hydraulic fracture surface. In our simulations, we have assumed that only one of the thermal cracks extends far enough to tie into natural fractures. In the absence of an analytical solution for flow through the complicated geometry of fractures, numerical simulation is used to obtain cumulative recovery.

We assume a single phase gas flow in a $1 \mu\text{d}$ permeability formation. The boundary and well pressures are 3500 and 500 psi (2.4×10^7 and 3.4×10^6 Pa), and production is simulated for a time period of 30 years. Figure 22 are the plan views of the pressure distribution after five years for the case of (a) no thermal cracks, and (b) with thermal cracks created. The pressures are in psi (and shown in Pa for consistency where necessary), and the dimensions of reservoir and fractures are shown in meters. The white arrows depict Darcy's velocity vectors.

It should be noted that in case (b), only one of the thermal cracks is assumed to have extended to intersect natural fractures. In reality, due to the presence of a network of natural fractures, more than one crack has the potential to grow and connect to existing fractures. The growth of multiple thermal cracks improves the productivity relative to that shown in Figure 22 (c).

Figure 22: a) Pressure distribution for stimulation with hydraulic fractures ($t = 5$ years), b) Pressure distribution for stimulation with hydraulic and thermal fractures ($t = 5$ years), c) Recovery improvement due to thermal cracks.

We believe that the examples of productivity improvement analysis given above are conservative, for the following reasons:

- The analysis does not take into account the effect that cooling/ freezing has on lowering fracture initiation and propagation pressures, as discussed previously
- The analysis does not take into account the possibility of cooling along the entire length of the fracture as it is being propagated during a hydraulic fracturing job; only near-wellbore cooling/ freezing effects are considered. Although it takes some time for effective cooling to take place along the fracture faces

of a growing fracture, one would expect there to be some beneficial effect of small thermal cracks initiating perpendicular to the hydraulic fracture when a cold fluid is used for stimulation

- The analysis does not consider the thermal cracks as initiation points for branching of the hydraulic fracture and the potential to better link up with natural fracture networks.

All of these items would be expected to further benefit hydrocarbon recovery when properly accounted for.

6. Conclusions

Production from low permeability formations such as shales relies on the connectivity of flow pathways. Any process that increases this connectivity therefore also enhances productivity. Thermal cooling / freezing and associated thermal shock is one such method for increasing connectivity by extending thermal cracks and possibly connecting these to the in-situ network of natural fractures. Our simulations show that thermal cooling / freezing / shock initiates thermal cracks, which open against the maximum in-situ horizontal effective stress. These cracks do not initially extend far from the face of the hydraulic fractures; however, they can be extended as the fracturing fluid is injected into them. How far the thermal cracks extend is a function of the strength of rock, the flow properties of reservoir rock and the rate of loading. The following conclusions are reached:

- Cooling of vertical and horizontal wellbores may facilitate subsequent hydraulic fracturing and result in more extensive rock formation damage achieved at lower fracturing pressures, which in turn may lead to a higher permeability for the flow of hydrocarbons with associated production gains.
- Cooling, when achieved along the main borehole and the hydraulic fracture itself, lowers in-situ thermal stress, which lowers the propagation pressure of the main hydraulic fracture(s), and may generate small thermal cracks perpendicular to the main fracture(s).
- A systematic sensitivity analysis of rock thermal fracturing process shows that the magnitude of this beneficial cooling effect on fracturing and hydrocarbon production is proportional to Young's Modulus, the coefficient of thermal expansion, and the applied temperature gradient, and inversely proportional to rock thermal conductivity and tensile strength/ fracture toughness.
- FEM techniques can be used to model and quantify the cooled zone around a wellbore and a hydraulic fracture, and also allows for an estimate of permeability enhancement due to thermal cracking to be made.
- Our simulation results clearly demonstrate that a non-trivial improvement in total hydrocarbon production is possible as a result of thermal cracking around the wellbore and around the hydraulic fracture itself. Our conservative estimate shows that volumetric rock stimulation around the wellbore within a 4 feet radius can improve hydrocarbon recovery by an additional 15-20%.

- Hydrocarbon production from low permeability formations such as shales depends, to a large extent, on the connectivity of natural fractures with induced hydraulic fractures. Our work shows that thermal shock during hydraulic fracturing can create a network of small cracks, which is expected to facilitate intersection and link up with natural fractures.
- Analytical calculation of permeability of a fractured rock in tight formation demonstrates an enhancement of 6 orders of magnitude of the original permeability of the reservoir rock.

7. Acknowledgment

We would like to acknowledge the computational resources at the University of Texas at Austin and financial support of a gift by Chevron to the R&D work of Dr. Tad Patzek.

References

- Al-Bazali T, Zhang J, Chenevert M, Sharma M. Factors controlling the compressive strength and acoustic properties of shales when interacting with water-based fluids. *International Journal of Rock Mechanics and Mining Sciences* 2008;45(5):729–38.
- Algu D, van Oort E, Landgrave S, Grant L, Hillburn D. A systematic approach to drilling and delivering wells in severely depleted sands at Ram Powell (GOM). *Society of Petroleum Engineers* 2007;.
- Allain C, Limat L. Regular patterns of cracks formed by directional drying of a colloidal suspension. *Phys Rev Lett* 1995;74:2981–4.
- Bahr H, Weiss H. Heuristic approach to thermal shock damage due to single and multiple crack growth. *Theoretical and applied fracture mechanics* 1986;6(1):57–62.
- Bahr HA, Weiss HJ, Bahr U, Hofmann M, Fischer G, Lampenscherf S, Balke H. Scaling behavior of thermal shock crack patterns and tunneling cracks driven by cooling or drying. *Journal of the Mechanics and Physics of Solids* 2010;58:1411–21.
- Boeck T, Bahr H, Lampenscherf S, Bahr U. Self-driven propagation of crack arrays: A stationary two-dimensional model. *Phys Rev E* 1999;59:1408–16.
- Cengel Y, Boles M. *Thermodynamics: An Engineering Approach*; McGraw-Hill. 4th ed.; p. 824.
- Charlez P. *Rock mechanics. volume 1*. Editions Technip, 1991.
- Charlez P. *Rock mechanics: petroleum applications. volume 2*. Editions Technip, 1997.
- Chen H, Teufel L, Lee R. Coupled fluid flow and geomechanics in reservoir study – i. theory and governing equations. *Society of Petroleum Engineers* 1995;.

- Chen J, Hou J, Wang R, Hui Y. The effect of knudsen diffusion and adsorption on shale transport in nanopores. *Advances in Mechanical Engineering* 2017;9(9):1687814017721858.
- 575 Chen S, Zhu Y, Wang H, Liu H, Wei W, Fang J. Shale gas reservoir characterisation: A typical case in the southern sichuan basin of china. *Energy* 2011;36(11):6609 –16.
- Chen Z, Narayan S, Yang Z, Rahman S. An experimental investigation of hydraulic behaviour of fractures and joints in granitic rock. *International Journal of Rock Mechanics and Mining Sciences* 2000;37(7):1061 –71.
- 580 Donohue D, Anstey N, Morrill N. Shale gas in the southern central area of new york state. Morgantown, USA: Department of Energy 1981;4.
- Dufresne E, Corwin E, Greenblatt N, Ashmore J, Wang D, Dinsmore A, Cheng J, Xie X, Hutchinson J, Weitz D. Flow and fracture in drying nanoparticle suspensions. *Physical Review Letters* 2003;91(22):224501.
- Dunn-Norman S, Abdalkadeer K, Senturk E, Rivera N, Prada M, Goodman H. Changes in near wellbore stress and fracture gradient due to cold water injection in a sirte basin field, libya 2009;.
- 585 Enayatpour S, van Oort E, Patzek T. Thermal shale fracturing simulation using the cohesive zone method (CZM). *Journal of Natural Gas Science and Engineering* 2018;55:476 –94.
- Gao Q, Tao J, Hu J, Yu XB. Laboratory study on the mechanical behaviors of an anisotropic shale rock. *Journal of Rock Mechanics and Geotechnical Engineering* 2015;7(2):213 –9.
- 590 Gonzalez M, Bloys J, Lofton J, Pepin G, Schmidt J, Naquin C, s. Ellis , Laursen P. Increasing effective fracture gradients by managing wellbore temperatures. In: IADC/SPE Drilling Conference. Society of Petroleum Engineers; 2004. .
- H.A. Bahr G. Fischer HW. Thermal-shock crack patterns explained by single and multiple crack propagation. *Journal of Materials Science* 1986;21:2716–20.
- 595 Hetttema M, Bostrøm B, Lund T. Analysis of lost circulation during drilling in cooled formations. Society of Petroleum Engineers 2018;.
- Hetttema M, Bostrøm B, Lund T, et al. Analysis of lost circulation during drilling in cooled formations. In: SPE Annual Technical Conference and Exhibition. Society of Petroleum Engineers; 2004. .
- Hiroki S. Mechanical properties of shale gas reservoir rocks and its relation to the in-situ stress variation observed in shale gas reservoirs. PhD Dissertation 2012;.
- 600 Horsrud P, Sgonstebo E, Boe R. Mechanical and petrophysical properties of north sea shales. *International Journal of Rock Mechanics and Mining Sciences* 1998;35(8):1009 –20.

- Huang J, Zou C, Li J, Dong D, Wang S, Wang S, Cheng K. Shale gas generation and potential of the lower cambrian qiongzhusi formation in the southern sichuan basin, china. *Petroleum Exploration and Development* 2012;39(1):75 – 81.
- Hull D, Caddock B. Simulation of prismatic cracking of cooling basalt lava flows by the drying of sol-gels. *Journal of Materials Science* 1999;34(23):5707–20.
- Ibanez WD. Deformation of shale: mechanical properties and indicators of mechanisms. Masters thesis, Texas A and M University 1993;.
- Ibanez WD, Kronenberg AK. Experimental deformation of shale: Mechanical properties and microstructural indicators of mechanisms. *International Journal of Rock Mechanics and Mining Sciences and Geomechanics Abstracts* 1993;30(7):723 –34.
- Incropera FP, DeWitt DP. *Introduction to Heat Transfer*. 2nd ed. Wiley, 1990.
- Islam A, Patzek T. Slip in natural gas flow through nanoporous shale reservoirs. *Journal of Unconventional Oil and Gas Resources* 2014;7:49–54.
- Javadpour F, Fisher D, Unsworth M, et al. Nanoscale gas flow in shale gas sediments. *Journal of Canadian Petroleum Technology* 2007;46(10).
- Jia B, Tsau J, Barati R. Evaluation of core heterogeneity effect on pulse-decay experiment. In: *Proceedings of the International Symposium of the Society of Core Analysis*, Vienna, Austria. 2017. p. 26–31.
- Jia B, Tsau J, Barati R. Experimental and numerical investigations of permeability in heterogeneous fractured tight porous media. *Journal of Natural Gas Science and Engineering* 2018;58:216 –33.
- Josh M, Esteban L, Piane CD, Sarout J, Dewhurst D, Clennell M. Laboratory characterisation of shale properties. *Journal of Petroleum Science and Engineering* 2012;88-89:107 –24.
- J.R.V. Brooks S.J. Stoker TC. Hydrocarbon exploration opportunities of the twenty-first century in the united kingdom. *AAPG Memoir* 74, Chapter 10 2001;.
- Keaney G, Jones C, Meredith P. Thermal damage and the evolution of crack connectivity and permeability in ultra-low permeability rocks. *American Rock Mechanics Association* 2004;.
- Kim KM, Kemeny J. Effect of thermal shock and rapid unloading on mechanical rock properties. *American Rock Mechanics Association* 2009;.
- Lake L. *Enhanced Oil Recovery*. Prentice Hall, 1989.
- Lau H, Yu M. Production technology challenges of tight and shale gas production in china. *International Petroleum Technology Conference* 2013;IPTC 17096.

van Oort E, Patzek T, Enayatpour S. Method of improving hydraulic fracturing by decreasing formation temperature. US Patent 9,920,608 2018;.

- 635 Patel H, Cadwallader S, Wampler J. Zipper fracturing: Taking theory to reality in the eagle ford shale. In: Unconventional Resources Technology Conference, San Antonio, Texas, 1-3 August 2016. Society of Exploration Geophysicists, American Association of Petroleum Geologists, Society of Petroleum Engineers; 2016. p. 1000–8.

Peebles M. Evolution of the gas industry 1980;.

- 640 Raterman KT, Farrell HE, Mora OS, Janssen AL, Gomez GA, Busetti S, Warren M. Sampling a stimulated rock volume: An eagle ford example. Unconventional Resources Technology Conference 2017;.

Ritchie R, Sakakura A. Asymptotic expansions of solutions of the heat conduction equation in internally bounded cylindrical geometry. *Journal of Applied Physics* 1956;27(12):1453–9.

- Sandler SI. Chemical, Biochemical, and Engineering Thermodynamics; John Wiley and Sons, Inc. 4th ed.;
645 p. 243.

Selley R. UK shale gas: The story so far. *Marine and Petroleum Geology* 2012;31(1):100 –9. Insights into Shale Gas Exploration and Exploitation.

Settari A, Warren GM. Simulation and field analysis of waterflood induced fracturing. Society of Petroleum Engineers 1994;.

- 650 Shabro V, Torres-Verdin C, Javadpour F. Numerical simulation of shale-gas production: From pore-scale modeling of slip-flow, knudsen diffusion, and langmuir desorption to reservoir modeling of compressible fluid. Society of Petroleum Engineers 2011;.

Sierra L, Mayerhofer M, et al. Evaluating the benefits of zipper fracs in unconventional reservoirs. In: SPE Unconventional Resources Conference. Society of Petroleum Engineers; 2014. .

- 655 Stephens G, Voight B. Hydraulic fracturing theory for conditions of thermal stress 1982;19:279–84.

Swann G, Munns J. The hydrocarbon prospectivity of britain onshore basins 2003;.

Tarasovs S, Ghassemi A. Self-similarity and scaling of thermal shock fractures. *Physical Review E* 2014a;90(1):012403.

Tarasovs S, Ghassemi A. Self-similarity and scaling of thermal shock fractures. *Phys Rev E* 2014b;90.

- 660 Wojnarowski P, Rewis A. Impact of fracturing caused by cold water reinjection in geothermal reservoir on early cold water breakthrough in production wells 2005;.

Yuan J, Jiang R, Zhang W. The workflow to analyze hydraulic fracture effect on hydraulic fractured horizontal well production in composite formation system. *Advances in Geo-Energy Research* 2018;2(3):319–42.

Zhang P, Hu L, Meegoda J, Gao S. Micro/nano-pore network analysis of gas flow in shale matrix. Scientific
665 reports 2015;5:13501.

Zielinski R, McIver R. Resource and exploration assessment of the oil and gas potential in the devonian gas
shales of the appalachian basin 1981;.

Zoback M. Reservoir Geomechanics. Cambridge University Press, 2007.

Zou C, Dong D, Wang S, Li J, Li X, Wang Y, Li D, Cheng K. Geological characteristics and resource
670 potential of shale gas in china. Petroleum Exploration and Development 2010;37(6):641 –53.

NOMENCLATURE

E	= Young Modulus of reservoir rock
ν	= Poisson's ratio of reservoir rock
ΔS	= change of Entropy
ΔG	= Gibbs free energy
ΔH	= Enthalpy change of reaction
α	= Linear coefficient of thermal expansion
$\sigma_{\theta\theta}$	= Tangential stress around the wellbore
$\Delta\sigma_{\theta\theta}^{\Delta T}$	= Variation of the tangential stress around the wellbore
S_{Hmax}	= Maximum horizontal stress
S_{hmin}	= Minimum horizontal stress
P_{pore}	= Pore fluid pressure
$P_{wellbore}$	= Wellbore fluid pressure
K_{IC}	= Fracture toughness
K	= Hydraulic conductivity
k	= Reservoir rock thermal conductivity
k	= Rock permeability
T_i	= Reservoir temperature
T_s	= Fracturing fluid temperature
C	= Reservoir rock specific heat
D	= Reservoir rock thermal diffusivity
d	= Length of thermal fracture
$\epsilon_{thermal}$	= Thermal strain
ΔT_c	= Critical cool down temperature
σ	= Total stress tensor
ϵ	= Mechanical strain
ϵ_{th}	= Thermal strain
T_{ref}	= Reference temperature
X_f	= Fracture half-length
t_f	= Thermal fracture width
β	= Constant term of RSM regression
$\mathcal{E}$	= Data regression residual
V_{dp}	= Dykstra-Parsons coefficient of heterogeneity

8. Appendix A: The Gas Flow Model Assumptions

The gas flow in porous media can be studied using Darcy's law incorporated into the conservation of mass equation. A quick overview of the assumptions and the equations used in the simulation of gas in a vertical well which was shown in this paper is given in this Appendix.

We are assuming that the flow is under isothermal condition and the thermal freezing was employed to freeze the rock and make the mechanical changes in the rock properties. The fluid compressibility is assumed to remain constant. Since the process is isothermal, the density in the equation of state is a function of pressure only and can be calculated using Equation (22)

$$\rho(p) = \frac{M_w}{Z(p)RT} p \quad (22)$$

Z is the gas compressibility factor and is equal to 1.0 for ideal gasses. For real gasses, Z can be obtained from the generalized compressibility factor diagram (Sandler, 2006). Assuming the gas to be Methane, critical temperature and pressure are obtained from the Table of liquid-vapor critical temperature and pressure for selected substances (Cengel and Boles, 2002) as 109.9°K and 45.79 atm. For the range of temperature and pressure of the reservoir, the compressibility factor can be obtained from the plot and approximated as:

$$Z(p) = -3.427 \times 10^{-24} p^3 + 5.38 \times 10^{-16} p^2 - 1.448 \times 10^{-8} p + 1.0055 \quad (23)$$

Pressure in Equation (23) is in Pa. Viscosity of the fluid is constant and rock is incompressible; therefore, the porosity does not change with pressure. Using the material balance equation for a single phase flow in porous media we get:

$$\frac{\partial(\rho\phi)}{\partial t} = -\nabla \cdot (\rho u) \quad (24)$$

u , in Equation (24) is the Darcy velocity or superficial velocity and equals:

$$u = \frac{q}{A} = -\frac{k}{\mu} \nabla \Phi \quad (25)$$

Φ is the potential and equals $p + \rho gh$. Ignoring gravity, the potential is equal to the pressure p .

If Darcy's transport law from Equation (25) is plugged into the material balance Equation (24) and gravity is neglected, we can arrive at the equation of pressure diffusivity in porous media:

$$\frac{\partial(\rho\phi)}{\partial t} = \nabla \cdot \left(\rho \frac{k}{\mu} \nabla p \right) \quad (26)$$

expanding Equation (26) we get:

$$\phi \frac{\partial(\rho)}{\partial t} + \rho \frac{\partial(\phi)}{\partial t} = \frac{k}{\mu} [\rho \nabla^2 p + \nabla \rho \cdot \nabla p] \quad (27)$$

in porous media the total compressibility c_t is the sum of the compressibility of the fluid and the formation.

$$\text{Total compressibility, } c_t = c_{\text{fluid}} + c_{\text{formation}} \quad (28)$$

fluid compressibility may include all the three phases of oil, gas and water, hence;

$$c_{\text{fluid}} = c_o S_o + c_g S_g + c_w S_w \quad (29)$$

we assume gas flow in an incompressible rock; therefore, the total compressibility in our formulation is:

$$c_t = c_g S_g \quad (30)$$

Rock or pore space compressibility is defined as

$$c_{\text{formation}} = \frac{1}{(\phi V_b)} \frac{d(\phi V_b)}{dp} = \frac{1}{(V_p)} \frac{d(V_p)}{dp} \quad (31)$$

in Equation (31), V_b , is the bulk volume, V_p is the volume of the pore spaces and p is the pore pressure.

fluid compressibility is defined as

$$c_{\text{fluid}} = \frac{1}{\rho} \frac{d\rho}{dp} \quad (32)$$

since the density varies with pressure, let's re-write the Equation (27) to bring the variation of density with pressure and the effect of compressibility into the diffusivity equation:

$$\underbrace{\phi \frac{\partial \rho}{\partial p}}_{\rho c_{\text{fluid}}} \frac{\partial p}{\partial t} + \underbrace{\rho \phi \left[\frac{1}{(\phi V_b)} \frac{d(\phi V_b)}{dp} \right]}_{c_{\text{formation}}} \frac{\partial p}{\partial t} = \frac{k}{\mu} \left[\rho \nabla^2 p + \underbrace{\left(\frac{d\rho}{dp} \nabla p \right)}_{\rho c_{\text{fluid}}} \cdot \nabla p \right] \quad (33)$$

now, let's use Equation (33) and replace the terms from Equations (31) and (32) and cancel out the density from both sides of the equation to bring the fluid and formation compressibilities to the left hand side of the equation.

$$\phi c_{\text{fluid}} \frac{\partial p}{\partial t} + \phi c_{\text{formation}} \frac{\partial p}{\partial t} = \frac{k}{\mu} [\nabla^2 p + c_{\text{fluid}} \nabla p \cdot \nabla p] \quad (34)$$

The two terms in the left hand side of the Equation (34) can now be added and the total compressibility appears in the equation. Further simplification of Equation (34) results in:

$$\phi c_t \frac{\mu}{k} \frac{\partial p}{\partial t} = \nabla^2 p + c_{\text{fluid}} (\nabla p \cdot \nabla p) \quad (35)$$

For analytical solutions of diffusivity equation, the term on the right hand side which includes the product of two pressure gradient will be neglected; however, this assumption is valid only for the zones far away from the wellbore where the pressure gradient is small. Neglecting the product results in:

$$\nabla^2 p = \frac{\mu c_t \phi}{k} \frac{\partial p}{\partial t} \quad (36)$$

Equation (35) is the pore pressure diffusivity equation and the reciprocal of the coefficient on the right hand side is called the diffusivity coefficient, denoted by α and it's a function of pressure.

$$\alpha(p) = \frac{k}{\mu c_t \phi} \quad (37)$$

Highlights

- Cooling along the borehole and the hydraulic fracture lowers the propagation pressure of the main fracture.
- Rock cooling efficiency is proportional to Young's modulus, the coefficient of thermal expansion and the applied temperature gradient.
- The small cracks created by the rock thermal shock are expected to facilitate intersection with natural fractures and enhance permeability.