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The effect of sufficient barrier layers on hydraulic fracturing design efficiency in one of the Iranian South hydrocarbon reservoirs

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Abstract
Hydraulic fracturing and matrix stimulation are two major methods of the reservoir stimulation. Hydraulic fracturing, which is the newest technique and technically more complex, is very useful in low permeability reservoirs. Although it has been used widely in hydrocarbon production wells, it is a new method in Iran. In this paper, the effect of sufficient barrier layers on hydraulic fracturing design efficiency was done for Bangestan reservoir (one of hydrocarbon reservoirs in south of Iran). To do this, at first, mechanical earth model (MEM) was developed. This model comprise of in situ stresses and physical properties of reservoir rock (like porosity and water saturation obtained from petrophysical well logs analysis) and determination of the rock fracture pressures and fracture propagation. Then, zone 5 and Sarvak zone of Bangestan reservoir were selected as candidate layers for hydraulic fracturing modelling. Finally, hydraulic fracture was designed for selected layers. In this design, the created fracture length in zone 5 is very shorter than the created fracture length in Sarvak zone. The results show that hydraulic fracturing can be done in Sarvak zone more successful than zone 5, which shows the importance of sufficient barrier layers in hydraulic fracture efficiency.
Keywords: *In situ stress, Mechanical earth model, Bangestan reservoir, Fluid and proppant, Hydraulic fracturing modelling*

1. Introduction
Reservoir stimulation is a technique to enhance oil and gas recovery from the hydrocarbon reservoirs. Hydraulic fracturing and matrix stimulation are two major methods of the reservoir stimulation. Hydraulic fracturing, which is the newest technique and technically more complex, is very useful in low permeability reservoirs. Hydraulic fracturing is widely used in the petroleum engineering, mining, and geotechnical industries. The most common application of this technology is enhancement of the fluid flow from oil, gas, and geothermal reservoirs in low permeability formations (Li et al. 2013). Since the early use of method, hydraulic fracturing has changed from a simple method by low volume and rate to a complex engineering method with diverse goals. For example, this method can be used for Improve well production by removing wellbore damages of drilling and production problems. In addition, this method can be used for creation of fractures with high conductivity that deeply propagate in layer, in low permeability reservoirs. In this reservoirs, due to low permeability for reservoir fluid flowing to the wellbore, and water injection for enhance recovery is not suitable, the hydraulic fracturing method is a suitable method to increasing permeability in well and reservoir. During a hydraulic fracturing treatment, fluids are injected into formation at a pressure high enough to cause tensile failure of the rock and propagate the fracture. As a result of a successful treatment, a path with much higher permeability than the surrounding formation is created from the well (Queipo et al. 2002). This technique has been widely used in the oil industry during the last 50 years. Stimulation of hydrocarbon wells and geothermal reservoirs are most important applications of hydraulic fracturing technology (Fjaer et al. 2008). The first hydraulic fracturing treatment was performed by Stanolind Oil and Gas in 1947 in the Hugoton field in Southwestern Kansas, USA which did not change the productivity of wells. Difficulty of the first operation was due to the fact that all the units, including mixing tanks, were kept 150 ft apart, due to the risk of fire (Aslam 2011). During the 1940s, the process of creating a fracture by the injection of oil and propping the fracture with sand was developed for stimulating sandstone formations. During the late 1940s, fracturing was a timid technique; but in the 1950s a proliferation took place (Economides and Nolte 2002). In 1964, new additives were developed that promoted the compatibility between the fracturing and reservoir fluids and helped achieve the goal of using aqueous based fluid (Hassebroek and Waters 1964). In 1966, hydraulic fracturing was used as a stimulation technique in the Hugoton field using a low-cost water based fluid (Aslam 2011). The growth of hydraulic fracturing treatments was rapid in the 1980s and today, hydraulic fracturing is used extensively in the petroleum industry to stimulate

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oil and gas wells in order to increase their productivity Nonetheless there is not any record of successful hydraulic fracturing in Iran. Four unsuccessful hydraulic fracturing treatments have been recorded in the Iranian oil industry. The three acid fracturing treatments had been done in a carbonate reservoir mostly composed of limestone in one Iranian oilfield and the single propped fracturing treatment was done in another carbonate reservoir (Heydarabadi and Moghadasi 2010). Studying the previous fracturing jobs shows that the lack of mechanical properties and appropriate geotechnical knowledge can be major causes leading to failure (Ashoori et al. 2014).

2. Case study situation

Iran has been producing oil and gas since 1911 and need to employ well stimulation techniques, are important and also necessary to prevent reservoirs form rapid decline in pressure and the rate of production. Most of the Iran's oil production comes from old super-giant oilfields that have been producing for a number of decades (Shahbazi et al. 2017). The Kopal oil field with 4×39 km^2 sizes has been located in 60 km Ahwaz northeast. The field discovered in 1965, by the first exploration well and the field exploitation started from 1970. This field consist of Asmari and Bangestan reservoirs that both of which produce oil. The Bangstan reservoir is one of the multilayer carbonate reservoirs in southern Iran that provides approximately 5% of the total production of the southern oil field region. The Bangstan reservoir in Kopal oil Field is a good candidate for a hydraulic fracturing operation due to sufficient amount of oil in place and the good quality of porosity with low permeability and flowing capacity in some of its production layers. Today, oil production in Bangstan reservoir in Kopal oil field is approximately 41000 bbl/day by 9 producing well.

3. Hydraulic fracturing design procedure

Studying the four unsuccessful previous fracturing jobs, two of which has been done to this oil field, shows that the lack of the rock mechanical properties, the region In situ stress field knowledge and appropriate geomechanical study can be major causes leading to failure. The world experiences study shows that the success in job is related to precise geomechanical studies and evaluation tests such as finite layer fracturing, calibration test, etc., so creation of mechanical earth model (MEM) for the wells is necessary as initial steps. It means that rock mechanic or geomechanic in petroleum engineering is related to rock stress and strength to formation behavior as a result of the producing oil. A well comprehensive geomechanical model comprise of the In situ stresses situation as a function of depth (direction and value), the physical properties of reservoir rock and its barrier formations (the rock strength and elasticity modulus), estimating pore pressure and determination of the rock fracture pressures and fracture propagation. This model must be capable of covering all the geomechanical analysis that require for layer fracturing. For the reservoir rock geomechanical model design, at first, the reservoir rock elasticity properties must be calculated. To calculate elasticity coefficient of the reservoir rock, at first, it is necessary to record some of the physical properties of the reservoir rock from petrophysical well logs analysis. These properties comprise the gamma ray value, density of the reservoir rock, neutron porosity value and the interval time of the compressive and shear waves passing through rock. So the initial mechanical earth model (MEM) for well prepared by use of the petrophysical data (GR, RHOB, NPHI, ΔT_C).

3.1 Elasticity Coefficient and Uniaxial Compressive Strength (UCS)

In order to develop mechanical earth model (MEM) elasticity coefficient must be calculated first. These coefficients can be obtained using empirical relations and also well log measurements. To calculate elasticity coefficient, sonic and density logs were employed. In sonic log calculations, only the compressional slowness data (ΔTc) was accessible. So the equation (1) was used as an empirical correlation in Bangstan reservoir to find shear slowness (ΔTs) (Abdideh and Fathabadi 2013).

$$\Delta t_s = 1.5452\, \Delta t_c + 21.2075 \quad (1)$$

The velocities of compressional waves and shear waves depend on the density and the elastic properties of rock as defined by the following characteristic equations:

$$\upsilon_d = \frac{1/2\left(\frac{\Delta t_c}{\Delta t_s}\right)^2 - 1}{\left(\frac{\Delta t_c}{\Delta t_s}\right)^2 - 1} \quad (2)$$

$$E_d = \frac{\rho_b\left[3 - 4\left(\frac{\Delta t_c}{\Delta t_s}\right)^2\right]}{\Delta t_s^{\,2} - \Delta t_c^{\,2}} \quad (3)$$

Where Dt_s is the slowness of shear wave (s/km), Dt_c represents slowness of compression wave (s/km), ρ_b stands for density (g/cm^3), υ_d is dynamic Poisson's ratio, and E_d indicates dynamic Young's modulus (Gpa). The elastic constants, thus determined, are dynamic values and must be related to static values in order to be used in hydraulic fracturing calculations. Static Poisson's ratio and static Young's modulus are both calculated via the following relations in Southwest of Iran. The results show good conformity with laboratory data (Abdideh and Fathabadi 2013).

$$E_s = 0.4145\, E_d - 1.0593 \quad (4)$$

$$\upsilon_s = 0.7\, \upsilon_d \quad (5)$$

Figure (1) shows the Young's modulus and Poisson's ratio for the well of study, in dynamic and static values.
The compressive stress required to cause failure is called the uniaxial compressive strength (UCS). UCS is the extensive rock strength parameter for geomechanical analysis. It is the best mechanical characteristic of rock for engineering evaluation of rock behavior. Several empirical equations exist for calculating UCS from log data. The researchers have used a correlation that was developed in Bangestan reservoir to calculate UCS and its result matches well to the laboratory core measurements: (Ashoori et al. 2014).

$$UCS = 135.9\, e^{-(4.8\, PHI)} \tag{6}$$

In this correlation, UCS is uniaxial compressive strength and PHI is porosity.

3.2 In situ stress

It has been reported that lack of accurate in situ stress values during the design of a hydraulic fracture can result in as much as a 50% error in the actual fracture length upon implementation (Vonieff and Holditch 1992). In other words, in situ stress plays an important role in all aspects of implementing a hydraulic fracture in oil and gas producing wells. Hydraulic fracture simulators require that the design engineer provide the in situ stress profile of the well as an input to the simulator (Mohaghegh et al. 2004).
In oilfield studies, the stresses are analyses only to determine the three principal components of the stress: a vertical component, and two minimum and maximum horizontal stress components. Vertical stress (σv) is obtained through integration of rock density from surface to the considered depth: (Zoback et al. 2003).

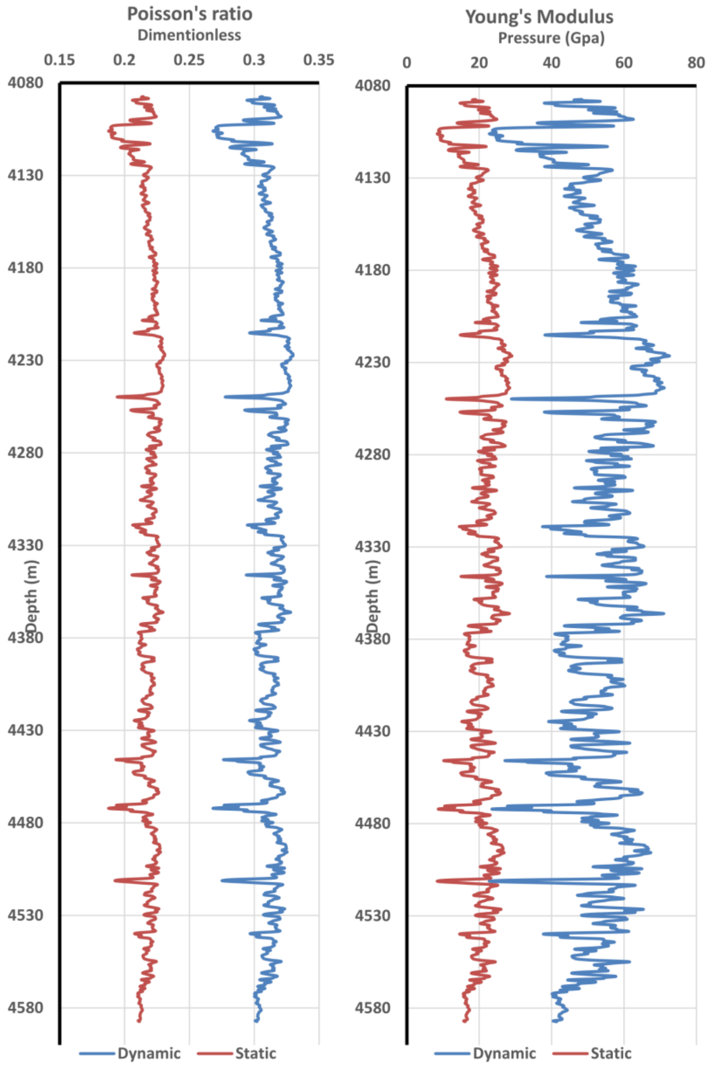

Fig 1.The Youngs modulus and Poissons ratio for the well of study (dynamic and static)

$$\sigma_V = \int_0^Z \rho(Z)\, g\, dZ \cong \bar{\rho}\, g\, z \quad (7)$$

Where (Z) is the rock density which is a function of depth; g is the gravity constant and r is the average density. In the borehole under study, r has been assumed equal to 2.56 (g/cm^3). In this paper, the horizontal stresses have been calculated based on the poroelastic theory. In a tectonically active basin tectonic stresses and strains arise from tectonic plate movement. If tectonic strains are applied to rock formations, these strains add a stress component in an elastic rock. The poroelastic horizontal strain model takes tectonic strains into account, and therefore accommodates anisotropic horizontal stresses (Fjaer et al. 2008).

$$\sigma_h = \frac{V_s}{1-V_s}\sigma_V - \frac{V_s}{1-V_s}\alpha P_P + P_P + \frac{E_s}{1-V_s{}^2}\varepsilon_x + \frac{E_s}{1-V_s{}^2}\varepsilon_y \quad (8)$$

$$\sigma_H = \frac{V_s}{1-V_s}\sigma_V - \frac{V_s}{1-V_s}\alpha P_P + P_P + \frac{E_s}{1-V_s{}^2}\varepsilon_x + \frac{E_s}{1-V_s{}^2}\varepsilon_y$$

$$\alpha = 1, \varepsilon_x = 1.5, \varepsilon_y = 0.5 \quad (9)$$

Where σh is minimum horizontal stress, σH represents maximum horizontal stress and υs stands for Poisson's ratio, α indicates Biot coefficient, Pp stands for pore pressure and Es for Young's modulus, and finally εx and εy present strain toward minimum and maximum horizontal stresses, respectively. The gradient of the average pore pressure in the borehole under examination is equal to .365(psi/ft).

According to figure (2), the comparison of in situ stress indicates that, in this well the stress regime is of normal type; i.e. $\sigma\upsilon > \sigma_{Hmax} > \sigma_{hmin}$. Thus the hydraulic fracture must propagate in a vertical plane and the fracture plane is perpendicular to the minimum horizontal in situ stress.

3.3 Formation breakdown pressure

Drilling a borehole will alter the in situ principal stresses, the vertical stress (σv) and the maximum and minimum horizontal stresses (σ_{Hmax} and σ_{hmin}), in such a manner as to maintain the rock mass in a state of equilibrium. This leads to a stress concentration around the well. In a linear elastic material, the largest stress concentration occurs at the borehole wall. Therefore, breakdown is expected to initiate at a pressure higher than the least horizontal stress. For the hydraulic fracturing study, consequently, stresses at the borehole wall are the ones that must be compared against a failure criterion (Ashoori et al. 2014). These stresses comprise the tangential stress (σθθ) that is tangential to the wellbore, radial stress (σrr) as a radial from well center to the wellbore and axial stress (σzz) that is parallel to the well axis.

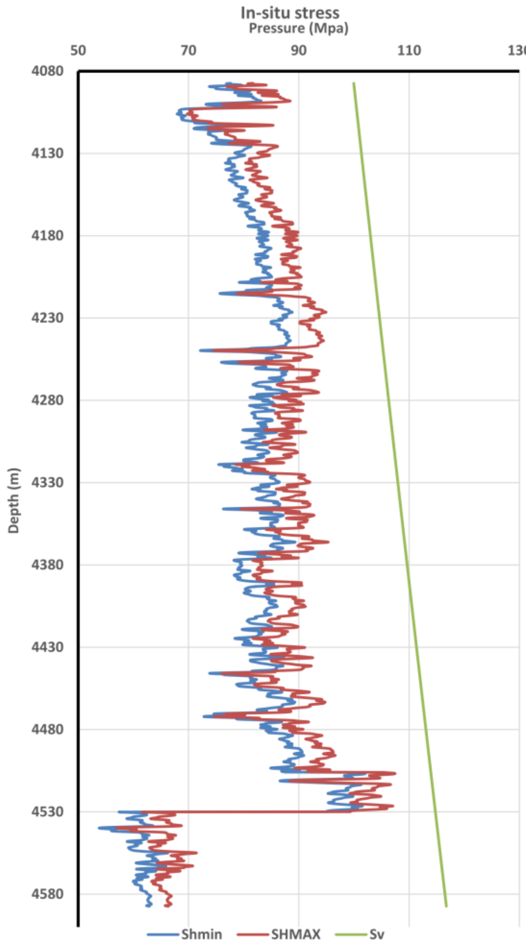

Fig 2. In situ stresses for the well of study

The equations to calculate these drilling-induced stresses in different direction are: (Al-Ajmi and Zimmerman 2006).

$$\sigma_{\theta\theta min} = 3\sigma_h - \sigma_H - P_P - P_W \quad (10)$$

$$\sigma_{\theta\theta max} = 3\sigma_H - \sigma_h - P_P - P_W \quad (11)$$

$$\sigma_{ZZmax} = \sigma_V + 2v\,(\sigma_H - \sigma_h) - P_P \quad (12)$$

$$\sigma_{ZZmin} = \sigma_V - 2v\,(\sigma_H - \sigma_h) - P_P \quad (13)$$

$$\sigma_{rr} = P_W - P_P \quad (14)$$

To develop the reservoir rock geomechanical model in this well, the appropriate failure criterion must be used on the basis of the drilling-induced stresses. There are numerous failure criteria that have been developed. The Mohr–Coulomb criterion is the simplest, and the most used in practice (Table 1). This criterion is appropriate for vertical wells (Al-Ajmi and Zimmerman 2006).

Table 1. The minimum induced stress to cause formation tensile failure models.

Tensile Failure Models	σ_3	***Borehole Tensile Failure will occur if :***
Vertical Tensile Failure (TVER)	$\sigma_{\theta\theta}$	$P_w \geq 3\sigma_h - \sigma_H - P_p - T$
Horizontal Tensile Failure (THOR)	σ_{zz}	$P_w \leq 3\sigma_h - \sigma_H - \sigma_V - 2v(\sigma_H - \sigma_h)$
Radial Tensile Failure (TCYL)	σ_{rr}	$P_W \leq P_P + T$

This criterion can present tensile failure and shear failure models. In hydraulic fracturing design the study of the tensile failures models is very important. To analyze tensile failure models by Mohr-Coulomb criterion should be:

$$(\sigma_3 - P_P) \leq T \tag{15}$$

Because of the fracture at the high depth is vertical, the vertical tensile failure model (TVER) was used. The major induced stress to create this failure model is the tangential induced stress. This parameter was used in hydraulic fracturing design. Table (1) shows the minimum induced stress to cause formation tensile failure models. In above equations, the rock tensile strength is equal to 0.1 × UCS. The results for breakdown pressure by Mohr-Coulomb criterion was shown in figure (3).

3.4 Investigation of candidate layers

Selection of candidate layer for hydraulic fracturing operation has its special challenges. Presentation of an accurate geomechanical model which saves the time and reduces the field attempts makes the selection of suitable layer possible (Abdideh and Ahmadifar 2013). In deep wells the difference between minimum and maximum horizontal stresses causes the hydraulic fracture propagate perpendicular to the minimum horizontal stress. The question is to know, for given injection conditions, whether the inter-bed is able or not to act as a barrier and to contain the fracture in the reservoir. The poor containment of a fracture has always had negative consequences on production, the worst case being when the fracture creates communication with a water bearing level (Charlez 1997). The suitable layer for hydraulic fracturing must have appropriate porosity and water saturation values. In addition, its minimum horizontal stress must be less than adjacent layers, to stop propagation of the fracture to the top and bottom layers. Figure (4) shows the minimum horizontal stress and water saturation curves. By considering the oil producing zones condition that have the above hydraulic fracturing conditions, the zone 5 and Sarvak zone were selected as a candidate layers for hydraulic fracturing design. Because of the Ilam zone was an aquifer layer, it was omitted from candidate layers.

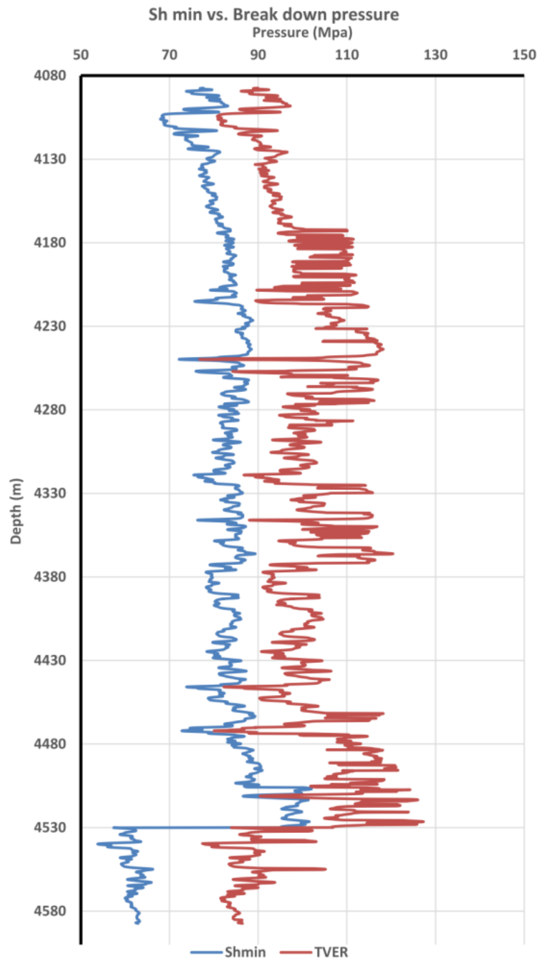

Fig 3. Breakdown pressure by Mohr-Coulomb criterion for the well of study

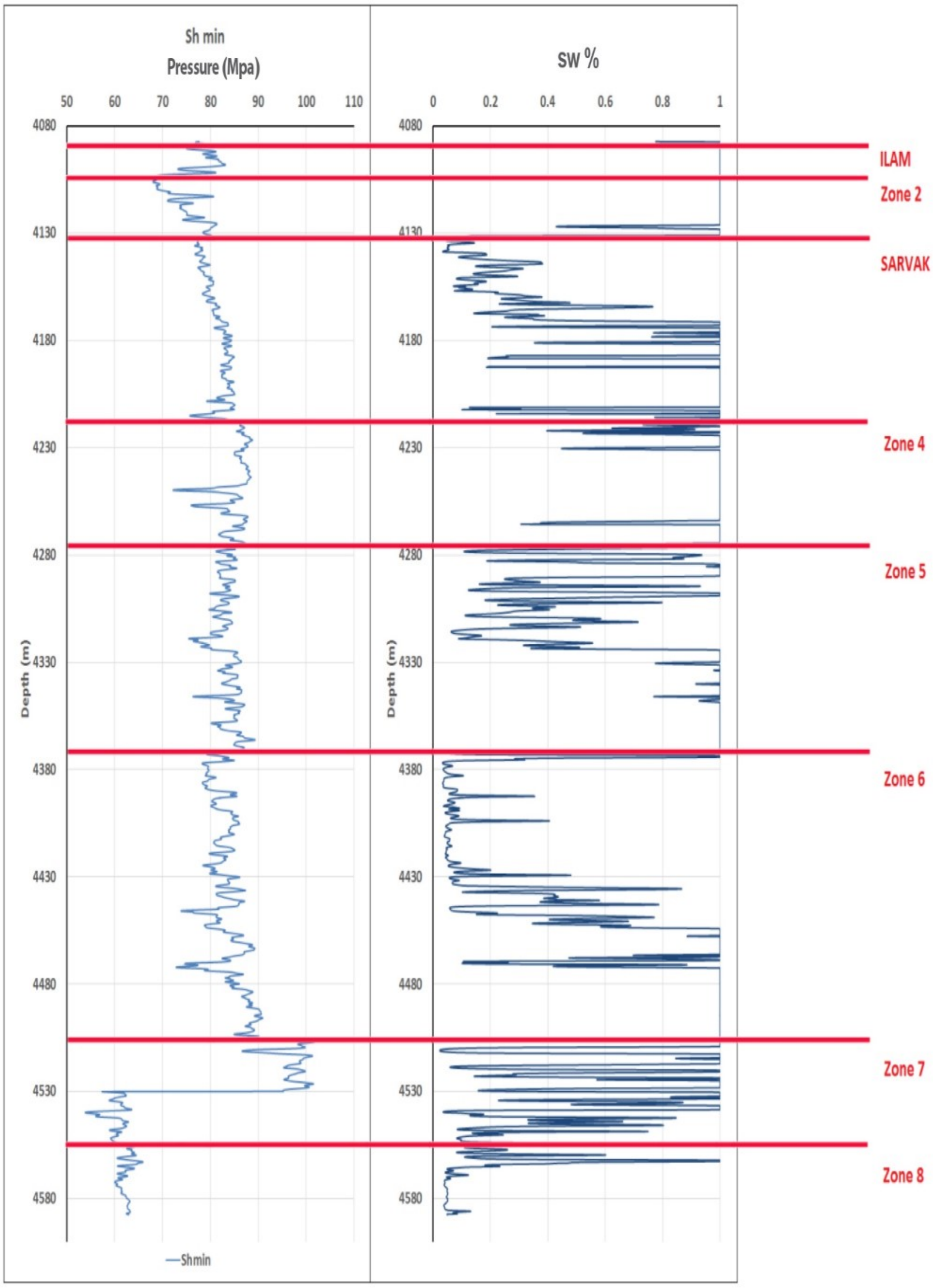

Fig 4. Minimum horizontal stress and water saturation curves for selecting candidate layers

Figure (5) that was given from figure (4) for zone 5 shows that only one section with higher pressure can be considered as the fracture barrier for the goal depth. Based on one fracture barrier existence instead of two fracture barriers, it is expected that fracture propagate insufficiently in producing layer. The appropriate depth for hydraulic fracturing in zone 5 according to one barrier layer, has been selected between the top barrier layer at 4273 m depth and the bottom optimal point at 4340 m depth. Figure (6) that was given from figure (4) for Sarvak zone, shows that two section with higher pressure can be simply considered as the fracture barriers for the goal depth. Based on fracture barriers, it is expected that fracture propagate sufficiently in producing layer. The appropriate depth for hydraulic fracturing in Sarvak zone according to barrier layers, has been selected between the top barrier layer at 4125 m depth and the bottom barrier layer at 4170 m.

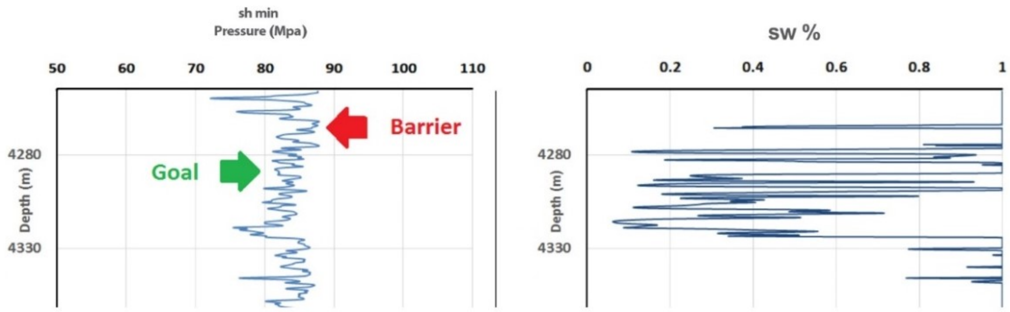

Fig 5. Investigation of barrier layers for zone 5 (from fig.4)

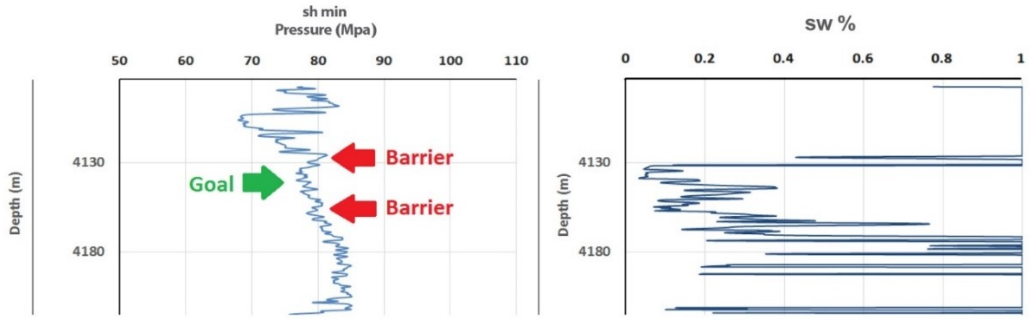

Fig 6. Investigation of barrier layers for Sarvak zone (from fig.4)

3.5 Hydraulic Fracturing Design

The hydraulic fracturing design initially require the appropriate fluid and proppant selection according to the reservoir conditions and obtaining the appropriate injection rate according to the fluid rheology. Then, in low permeability zones, the fracture must be designed in a way that it obtains maximum fracture length. The controlling factor of fracture length is that the fracture must not passing through the barrier layers. By fluid loss control in vertical fractures that limited by barrier layers, fractures expand longitudinally. So fracture length is increased.

3.5.1 Fluid and proppant selection

Water base fluids are the most common fluid in hydraulic fracturing job because of low cost, high efficiency and simple control. According to this point that our reservoir rock is not sensitive to water base fluid, the best selection according to financial approach and availability, is the water base fluids. To increase viscosity of water base fluid, polymers are used. The important point to selection of the polymer is the temperature effect on the viscosity. Therefore, the reservoir temperature is the main criteria to selecting fluid. According to the reservoir temperature and conditions such as insensitivity to water base fluid, the HPG fluid with HG25G2K commercial name was used for modeling. Figure (7) shows the viscosity of the fluid according to time.

After selecting the fluid, the proppant must be selected. The most important factor in proppant selection is bearing the fracture closing pressure which is considered equal to minimum horizontal stress. Other factors are cost of proppant and its availability. According to these factors, Badger sand selected as a proppant to both layers. According to the calculated in situ stresses, this proppant has the capability of bearing the fracture closing pressure.

3.5.2 Selection of the simulation model and injection rate

The FracproPT software was used to hydraulic fracturing modeling in zone 5 and Sarvak zone. This software can be used in oil and gas wells for hydraulic fracturing design, simulation and analysis which has 2D and 3D models. P3D-lumped model was used which provides results with a high degree of accuracy.

Another important parameter in hydraulic fracturing design is the fluid injection rate that determines fracture dimensions. The injection rate must be high enough to improve hydraulic fracture job efficiency by reducing the time of fluid loss, increasing the fracture width and proppant transmission capability to the fracture. The injection rate varies with fluid type, it means that by increasing fluid viscosity lower injection rate and higher pressure is required. The fracture dimensions must be in a way that it has the maximum fracture length with suitable fracture width to receive proppant. According to these factors, the 10, 20 and 30 bbl/day injection rates to calculate fracture dimensions has been considered by P3D-lumped model. The results shown that the injection rates less than 30 bbl/day cannot create the suitable fracture width to receive proppant. So the 30 bbl/day injection rate was selected for the fluid.

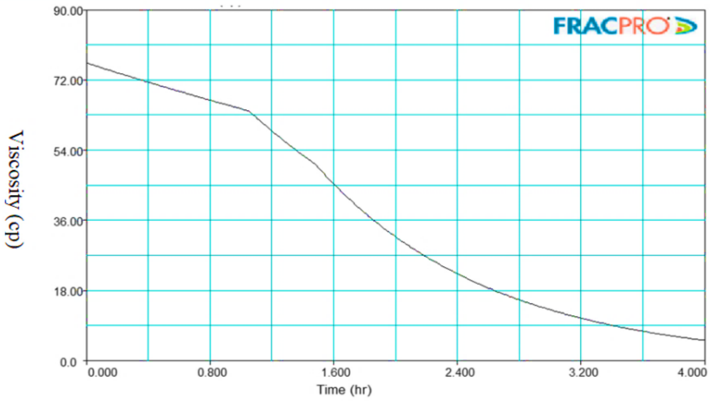

Fig 7. The viscosity of the HG25G2K fluid according to time

4. Hydraulic fracturing modeling results

4.1 Results for zone 5

For zone 5 , because there was only one barrier upper the producing zone , simulation was done in the condition that the created fracture do not pass thorough top barrier layer and do not pass through bottom layer. The appropriate depth for hydraulic fracturing in zone 6 according to barrier layers, has been selected between the top barrier layer at 4273 m depth and above the bottom layer at 4340 m depth. Then simulation done by 30 bbl/day injection rate. The fracture propagation was done before fracture reached the top barrier layer and bottom layer and then injection stopped. Figure (8) shows the fracture propagation simulation in zone 5 and Figure (9) shows the result for fracture conductivity. Fracture conductivity, defined as fracture permeability times width ($k_f w$) is a measure of how easily fluids flow through a fracture. Dimensionless fracture conductivity (F_{CD}) is defined as: (Guo et al. 2017).

$$F_{CD} = \frac{k_f w}{k\, x_f} \tag{16}$$

F_{CD} equal to k_f w fracture conductivity, k_f w (md-ft), divided by reservoir permeability, k (md) multiplied by the fracture half-length, x_f (ft) provides a comparison of the flow capacity of the fracture that transmits the fluid into the wellbore with the flow capacity of the reservoir that delivers the fluid into the fracture. Both fracture conductivity and dimensionless fracture conductivity are key parameters for fracture treatment designs. Depending on the reservoir permeability and the fracture length and conductivity achieved, the production rate of a fractured well is usually limited by one of the two influxes described above. An F_{CD} value in the range between 1 and 10 is generally obtained in fracture design. The analysis indicate that low permeability reservoirs, naturally leading to a fracture with higher dimensionless fracture conductivity, would benefit greatly from increasing the fracture length, and high permeability reservoirs, naturally leading to a fracture with lower dimensionless fracture conductivity, require higher fracture conductivity for more effective stimulation (Guo et al. 2017). So, in low permeability zone 5, the goal is to obtain longer fracture length. For zone 5, the created fracture length is 66 m which is short length as the result of insufficient barrier layers and the acceptable F_{CD} is equal to 2.139. The fracture conductivity is related to concentration of proppant in fracture. Figure (10) shows the result for proppant concentration in fracture. According to figure (10), it can be concluded that proppant is situated well in fractures that shows the appropriate fluid and proppanet selection. Finally, results show that hydraulic fracturing can be carefully employed in zone 5. Figure (11) shows the result for temperature variation of fluid in fracture after injection. It must be noted that temperature variation is the key parameter in fluid viscosity and can change the fracture dimensions.

4.2 Results for Sarvak zone

For Sarvak zone simulation was done in condition that the created fracture do not pass thorough barrier layers. The appropriate depth for hydraulic fracturing in Sarvak zone according to barrier layers, has been selected between the top barrier layer at 4125 m depth and the bottom barrier layer at 4170 m depth. Then simulation was done by 30 bbl/day injection rate. The fracture propagation was done before fracture reached the barrier layers and then injection stopped.

Figure (12) shows the fracture propagation simulation in Sarvak zone. Figure (13) shows the result for fracture conductivity. In low permeability Sarvak zone, the goal is to obtain longer fracture length. For Sarvak zone, the created fracture length is 130 m which is long length as the result of sufficient barrier layers and the acceptable F_{CD} is equal to 0.795. The fracture conductivity is related to concentration of proppant in fracture. Figure (14) shows the result for proppant concentration in fracture. According to figure (14), it can be concluded that proppant is situated well in fractures that shows the appropriate fluid and proppant selection. Finally, results show that hydraulic fracturing can be successfully employed in Sarvak zone. Figure (15) shows the result for temperature variation of fluid in fracture after injection that could be used to fluid optimizing and fluid loss control.

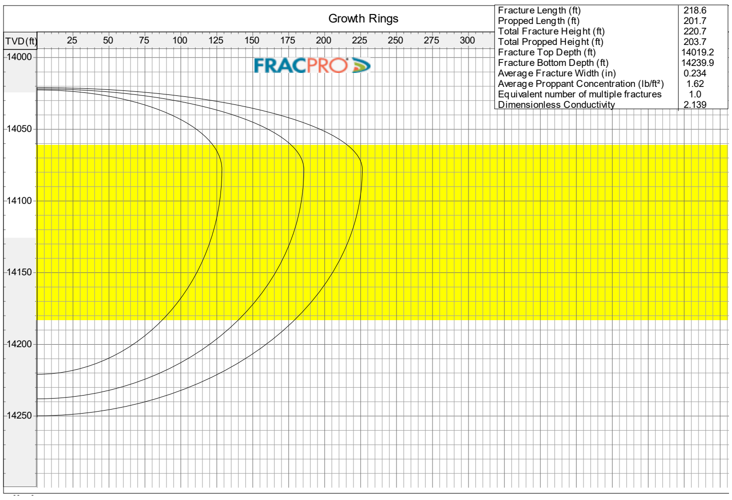

Fig 8. Fracture propagation simulation for zone 5

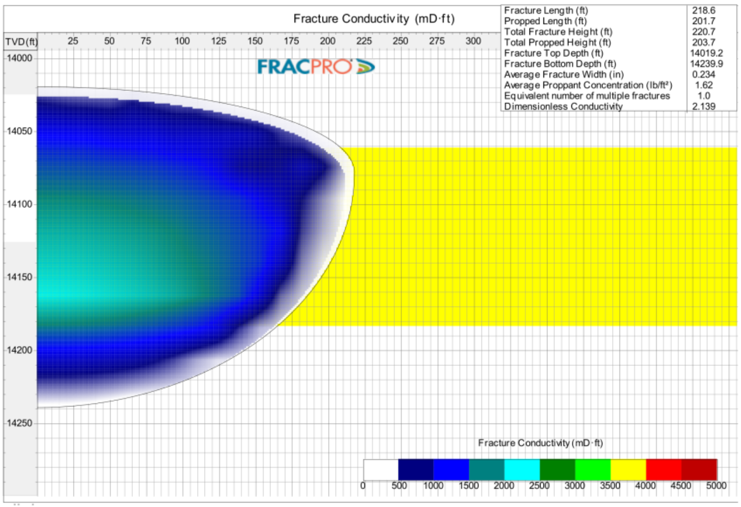

Fig 9. Fracture conductivity simulation for zone 5

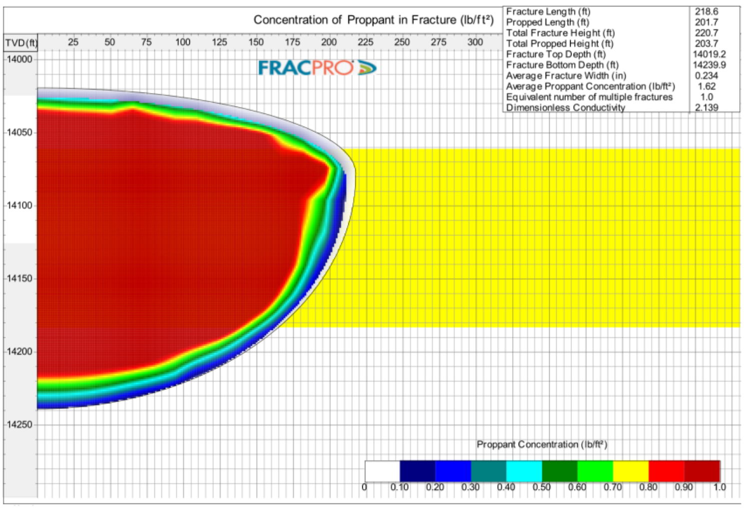

Fig 10. Proppant concentration in fracture simulation for zone 5

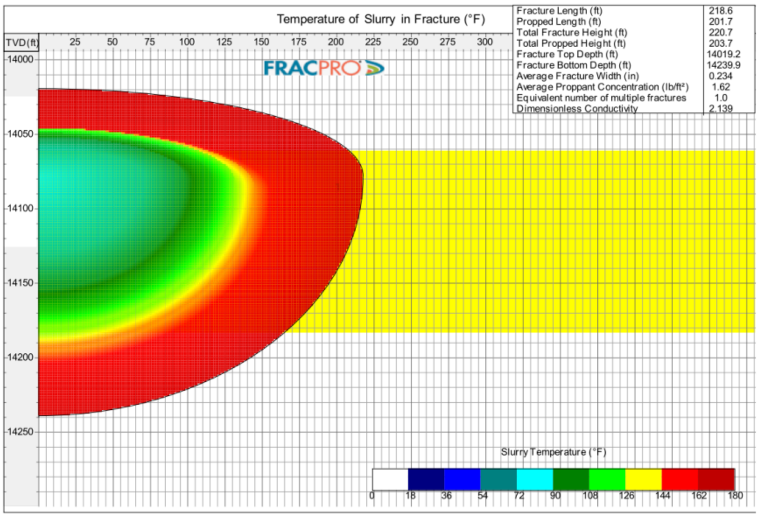

Fig 11. Temperature variation of fluid in fracture simulation for zone 5

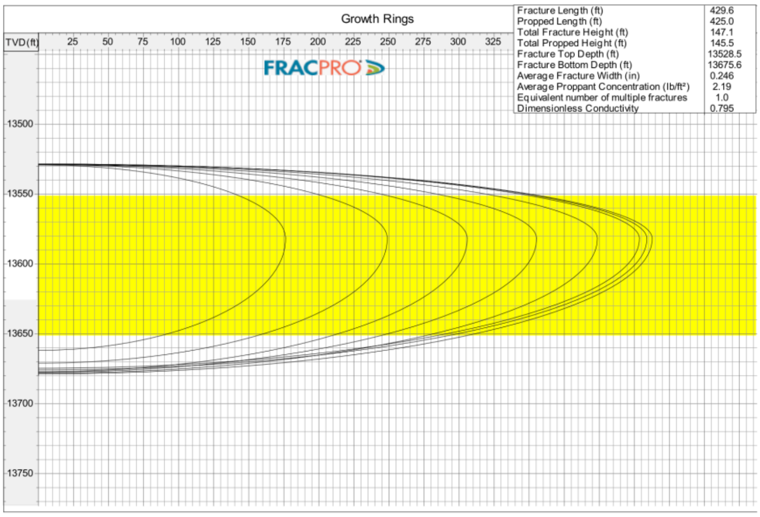

Fig 12. Fracture propagation simulation for Sarvak zone

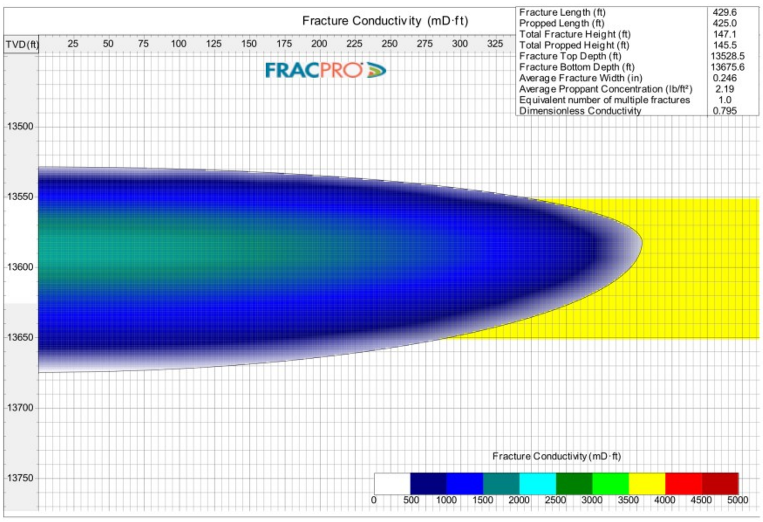

Fig 13. Fracture conductivity simulation for Sarvak zone

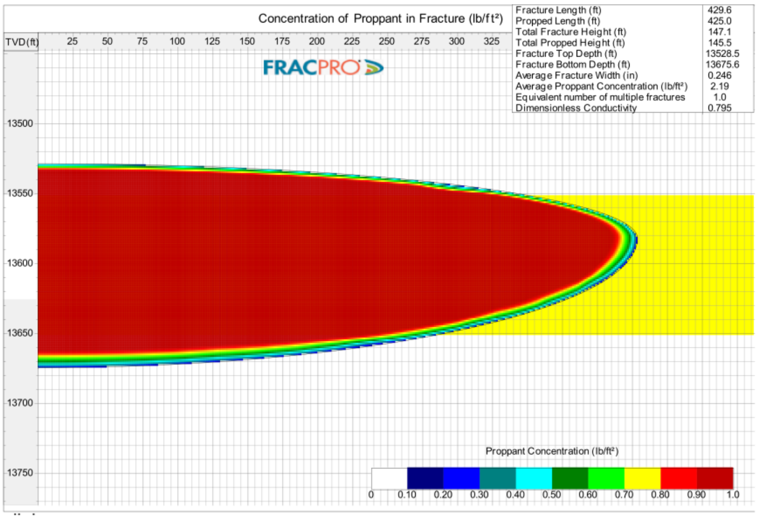

Fig 14. Proppant concentration in fracture simulation for Sarvak zone

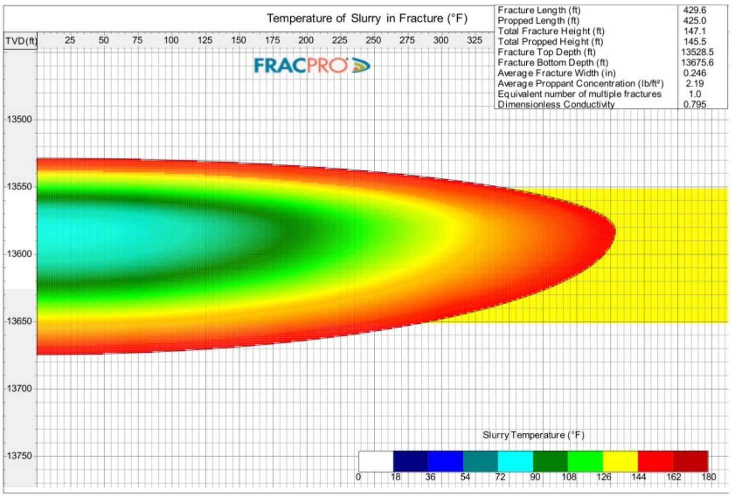

Fig 15. Temperature variation of fluid in fracture simulation for Sarvak zone

5. Conclusion

The suitable layer for hydraulic fracturing design that is very useful in low permeability reservoirs, must have appropriate porosity and minimum horizontal stress differences with adjacent layers, to stop propagation of the fracture to the top and bottom layers. In addition, the value of water saturation must be considered. In this paper, the stresses were determined using the poroelastic method and based on petrophysical data. The stress regime existing in the borehole under examination is of normal type and due to stress regime, the fracture will propagate in a vertical plane. The breakdown pressure was determined based on the Mohr–Coulomb criterion. Calculation of the stress gradient, percentage of water saturation and porosity indicate that, in this well, the zone 5 and Sarvak zone of Bangstan reservoir are candidate layers for hydraulic fracturing design. Based on reservoir temperature and conditions such as not sensitivity to water base fluid, the HPG fluid with HG25G2K commercial name was used for modeling. Subsequently, Badger sand was selected as a proppant to both layers. According to the calculated in situ stresses, this proppant has the capability of bearing the fracture closing pressure. Then the P3D-lumped model was used to simulation that which provides results with a high degree of accuracy. The results show that the injection rates less than 30 bbl/day cannot create the suitable fracture width to receive proppant. Therefore, the 30 bbl/day injection rate was selected for the fluid. The appropriate depth for hydraulic fracturing in zone 5 based on only one barrier layer, has been selected between the top barrier layer at 4273 m depth and above the bottom layer at 4340 m depth. In low permeability zone 5, the goal is to obtain longer fracture length. For zone 5, the created fracture length is 66 m which is short length as the result of insufficient barrier layers and the acceptable F_{CD} value equal to 2.139. The appropriate depth for hydraulic fracturing in Sarvak zone based on barrier layers, has been selected between the top barrier layer at 4125 m depth and the bottom barrier layer at

4170 m depth. In low permeability Sarvak zone, the goal is to obtain longer fracture length. For Sarvak zone, the created fracture length is 130 m which is long length as the result of s1ufficient barrier layers and the acceptable F_{CD} is equal to 0.795. In this design, the created fracture length in zone 5 is very shorter than the created fracture length in Sarvak zone. The results show that hydraulic fracturing can be done in Sarvak zone more successful than zone 5, which shows the importance of sufficient barrier layers in hydraulic fracture efficiency.

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