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Research Note

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Investigation and Selection of Suitable Layers in Bangestan Reservoir for Hydraulic Fracturing Operation

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Abstract. *Hydraulic fracturing is a process applied to boreholes to improve the ability of fluids (such as oil and gas) to flow to the hole and be recovered. Recent investigation has shown that fractures can play a major role in the productivity of low permeability formations. The Ahwaz oil field is one of the largest in South West Iran. The Bangestan reservoir in this field, with a suitable amount of oil in place and good rock reservoirs, has been selected for the present research work. The pressure profile has been calculated in tight reservoirs in a few wells, for the purpose of hydraulic fracturing operation studies. In this work, the pore pressure was calculated by using the available field data in the carbonated reservoir of the Ahwaz field. The results indicate that the Ilam formation could be a good candidate for hydraulic fracturing.*

Keywords: *Hydraulic fracturing; Minimum horizontal stress; Stress gradient; Bangestan reservoir.*

INTRODUCTION

Hydraulic Fracturing is a well stimulation treatment and technical operation used to enhance production from oil and gas wells. The process involves the injection of various fluids into the formation at a pressure high enough to cause a tensile failure of the rock and propagate the fracture. Oil and gas reservoirs with a low capacity for the flow of fluids usually require hydraulic fracturing to make them commercially viable [1-5].

The Bangestan reservoir in the Ahwaz oil field is one of the carbonate reservoirs in Southern Iran, providing approximately 5% of the total production of the southern oil field region. Because of a sufficient amount of oil in place and the good quality of porosity with low permeability and flowing capacity in some of the production layers, it is a good candidate for a hydraulic fracturing operation. For the above reasons, at the beginning of a fracture reservoir study, it is necessary to conduct some important rock mechanics tests on different reservoir rock samples for obtaining more information on the physical and mechanical properties of reservoir rock. Knowledge of the vertical profile of the minimum horizontal stress (or closure pressure) is one of the most important parameters in a hydraulic fracturing operation [6,7]. A detailed depth-to-depth determination of minimum horizontal stress is essential for three reasons. First, at typical reservoir depths, fracturing pressure is a strong function of minimum horizontal stress. Second, the value of minimum horizontal stress at the center of the perforations is the base to which net pressure is added to obtain fracture propagation pressure. Third, it is generally accepted that stress variation between the pay zone and adjacent layers is the most important controlling factor for creating fracture height containment [8].

The uncertainty in the results of hydraulic fracturing conducted in different fields is due to the lack of accurate data to estimate a valid stress profile, which is one of the key problems in fracture treatment design. Various methods for estimation of stress gradient and fracture gradient in tight rocks have been applied; the two most important methods are as follows:

1. Laboratory Measurements: This consists of determination of the mechanical properties of reservoir

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rock and the use of mathematical equations for converting these properties to a stress gradient or the direct measurement of a fracture gradient in the laboratory.

2. Well Operation Tests: Well operation tests and their analysis are undertaken with the aim of estimating the stress gradient; for example, the min-fracture test or step rate test [9,10].

In this work, an attempt has been made to use the present data and, based on the above two methods, estimate and calculate the stress gradient and fracture gradient in the Bangestan reservoir and any other similar reservoirs.

MINIMUM HORIZONTAL STRESS

From the results of the experiments and studies in operational activities and applications of modeling in hydraulic fracturing, it is understood that one of the most important parameters of designing hydraulic fracturing is to determine the depth of fracturing, which is related to minimum horizontal stress. In a hydraulic fracturing process, the fractures are usually in a perpendicular direction to the direction of minimum horizontal stress. In addition, the minimum horizontal stress is to be the minimum pressure to be applied. Also, in case of a single existing fracture, the minimum stress pressure needed to close the fracture is called the closure stress. In successful hydraulic fracturing, the internal pressure must be higher than the minimum horizontal stress, to prevent the fracture being closed. Minimum horizontal stress can be calculated, based on the Eaton equation [11]:

$$\sigma_h = \frac{v}{1-v}(\sigma_v - P_p) + P_p. \tag{1}$$

The range of the Poisson ratio for Bangestan rock is 0.3 to 0.37. Knowing the Poisson ratio range, Equation 1 can be used for plotting the stress gradient versus the Poisson ratio for different reservoir pore pressure gradients. Drawing the stress profile, with relation to depth, is one of the important and effective stages for selecting the depth interval for hydraulic fracturing. In addition, with the use of stress contrast between layers during the operational activity of hydraulic fracturing, with the help of 2D models, the height of the fracture can be estimated. For calculating the stress at each depth, using equation 1, the quantity of every parameter should be determined. For the calculation of horizontal stress in the Bangestan reservoir, the stress gradient of the top layers (i.e., vertical stress gradient) must be considered equivalent to a gradient of 1.1 (psi/ft). Also, in this calculation, the mean sum of the Poisson ratio, which is equal to 0.32, should be used. In case of reservoir pressure, statistic pressure data and RFT data and, also, estimated pressures, which are obtained from the decreased trend of reservoir pressure, can be used. Hence, considering the gradient stress of the top layers equivalent to 1.1 (psi/ft), the Poisson ratio equivalent to 0.32, and using Equation 1, the stress gradient for a given depth can be estimated by the following equation:

$$\sigma_h = 0.5294P_p + 0.5176. \tag{2}$$

As it is known that all the rock mechanics properties of Bangestan reservoir rocks in Southern Iran are similar, Equation 2 can be used for stress calculation in the above reservoirs. Hence, this equation can be applied for calculation of drawing the profiles of stress in different wells of Bangestan reservoirs in Southern Iran.

Calculation of Fracture Gradient

The pressure fracture (fracture gradient) is the pressure which is obtained due to fracture rocks, and this fracture which comes from the pressure fracture will remain open against minimum horizontal stress. The difference between a pressure fracture with minimum horizontal stress is called net pressure (P_n); hence, the pressure fracture can be defined as [1]:

$$FG = \sigma_h + P_n. \tag{3}$$

Calculation of the fracture gradient for Bangestan reservoir rocks for three pore pressure gradients (0.392, 0.426 and 0.519 (psi/ft)) is shown in Tables 1 to 4 [12]. Figures 1 to 3 show the calculated fracture gradient for the above three pore pressure gradients versus the Poisson ratio. As can be seen, each of the above figures shows a linear relation between the fracture gradient and Poisson ratio. Generally, the linear relation can be written as:

$$FG = av + b. \tag{4}$$

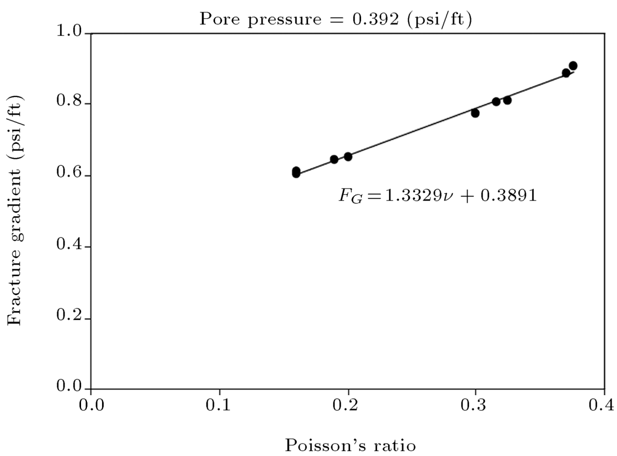

Figure 1. Fracture gradient determined based on Poisson's ratio at pore pressure gradient of 0.392 psi/ft.

Table 1. Measurement of fracture gradient for two rock samples of well B1 of Bangestan reservoir.

Well	**Sample Number**	**Depth (ft)**	**Frequency (Hz)**	**Net Stress (psi)**	**Acoustic Velocity**		**Young Modulus (1000000 psi)**	**Poisson's Ratio**
					Compression (μs/ft)	**Shear (μs/ft)**		
B1	1	12945	250 K	5000	60.0	94.5	9.34	0.16
	2	12653	250 K	5000	58.6	109.5	7.58	0.30
Well	Sample Number	Pore pressure gradient (psi)	Fracture gradient (psi)	Net overburden pressure (psi)	Fracture closure pressure (psi)	Tectonic strain (micro strains)	Tectonic strain	Net pressure (psi)
B1	1	0.392	0.604	9167	6819	0	0	1000
		0.426	0.631	8727	7174	0	0	1000
		0.519	0.707	7526	8147	0	0	1000
		0.519	0.598	7526	6746	0.150	0.1401	1000
		0.519	0.815	7526	9548	150	0.1401	1000
	2	0.392	0.774	8960	8798	0	0	1000
		0.426	0.794	8531	9044	0	0	1000
		0.519	0.847	7356	9715	0	0	1000
		0.519	0.757	7356	8578	0.150	0.1137	1000
		0.519	0.937	7356	10852	150	1137	1000

Table 2. Measurement of fracture gradient for a rock sample of well B2 of Bangestan reservoir using static and dynamic tests.

Well	**Test**	**Depth (ft)**	**Frequency (Hz)**	**Net Stress (psi)**	**Acoustic Velocity**		**Young Modulus (1000000 psi)**	**Poisson's Ratio**
					Compression (μs/ft)	**Shear (μs/ft)**		
B2	Dynamic	12800.197	1 MHz	6000	55.7	109.3	7.05	0.325
	Static	12800.197	Static	6000	-	-	1.45	0.37
Well	Test	Pore pressure gradient (psi)	Fracture gradient (psi)	Net overburden pressure (psi)	Fracture closure pressure (psi)	Tectonic strain (micro strains)	Tectonic strain (psi)	Net pressure (psi)
B2	Dynamic	0.392	0.811	9064	9378	0	0	1000
		0.426	0.828	8630	9603	0	0	1000
		0.519	0.877	7442	10220	0	0	1000
		0.519	0.785	7442	9042	0.150	11772.816	1000
		0.519	0.968	7442	11397	150	11772.816	1000
	Static	0.392	0.808	9064	10362	0	0	1000
		0.426	0.902	8630	10541	0	0	1000
		0.519	0.940	7442	11028	0	0	1000
		0.519	0.923	7442	10810	.150	-217.635	1000
		0.519	0.957	7442	11245	150	-217.635	1000

The constant values, a and b, in Equation 4 for pressure gradients of 0.392 (psi/ft) are equivalent to 1.3329 and 0.3891; for 0.426 (psi/ft) are equivalent to 1.2709 and 0.426; and for 0.519 (psi/ft) are 1.0959 and 0.531, respectively (Figures 1 to 3). For any other reservoirs, constants a and b should be determined, accordingly. Plotting the constant values a and b for pressure gradients of 0.392, 0.426 and 0.519 (psi/ft) (Figures 4 and 5) indicates that these constant values change with gradient linearly. In indicates that these

Table 3. Measurement of fracture gradient for a rock sample of well B3 of Bangestan reservoir using static and dynamic tests.

Well	**Test**	**Depth (ft)**	**Frequency (Hz)**	**Net Pressure (psi)**	**Acoustic Velocity**		**Young Modulus (1000000 psi)**	**Poisson Ratio**
					Compression (μs/ft)	**Shear (μs/ft)**		
B3	Dynamic	11277.195	1 MHz	6000	53.6	103.2	8.8	0.316
	Static	11277.195	Static	6000	-	-	1.52	0.38
Well	Test	Pore pressure gradient (psi)	Fracture gradient (psi)	Net overburden pressure (psi)	Fracture closure pressure (psi)	Tectonic strain (microstrains)	Tectonic strain (psi)	Net pressure (psi)
B3	Dynamic	0.392	0.807	4419	8105	0	0	1000
		0.426	0.826	4802	8311	0	0	1000
		0.519	0.876	5848	8874	0	0	1000
		0.519	0.759	5848	7555	0.150	-1319.84	1000
		0.519	0.993	5848	10194	150	-1319.84	1000
	Static	0.392	0.907	4419	9231	0	0	1000
		0.426	0.921	4802	9383	0	0	1000
		0.519	0.958	5848	9799	0	0	1000
		0.519	0.937	5848	9572	0.150	-227.419	1000
		0.519	0.978	5848	10027	150	-227.419	1000

Table 4. Measurement of fracture gradient in three different pressures in Bangestan rock reservoir.

Well Number	**Depth (m)**	**Poisson Ratio**	**Fracture Gradient (psi/ft)**		
			$p_p = 0.519$	$p_p = 0.426$	$p_p = 0.392$
48	3599.2	0.19	0.74	0.669	0.643
49	3601.0	0.16	0.714	0.639	0.611
49	3633.3	0.2	0.748	0.678	0.653
63	3945.4	0.16	0.707	0.631	0.604
63	3856.4	0.3	0.847	0.794	0.774
214	3901.3	0.325	0.877	0.828	0.811
214	3814.7	0.371	0.940	0.902	0.888
217	3437.1	0.316	0.876	0.826	0.807
217	3361.3	0.376	0.958	0.921	0.907

constant values change with gradient linearly. In this case, the constant value a decreases with increasing pressure gradient, but constant value b increases with increasing pressure gradient. The linear relationship is given in Equations 5 and 6 for constants a and b, respectively:

$$a = 1.8694P_p + 2.0664, \tag{5}$$

$$b = 1.1182P_p + 0.0494. \tag{6}$$

These equations can be used for any similar Bangestan reservoir. Calculation of the fracture gradient has been carried out for a net pressure of 1000 (psi). To use Equation 4 in any net pressure rather than a pressure of 1000 (psi), Equation 6 can be modified as below:

$$b = 1.1182P_p - 0.0494 - 0.0816(1 - 10^{-3}P_n). \tag{7}$$

However, applying net pressure causes the fracture to remain open against the minimum horizontal stress. Hence, considering a net pressure of 1000 (psi) is recommended. With an estimated Poisson ratio of 0.32 and combining Equations 4 and 6 at a net pressure equivalent to 1000 (psi), the fracture gradient can be estimated as a function of the reservoir pressure

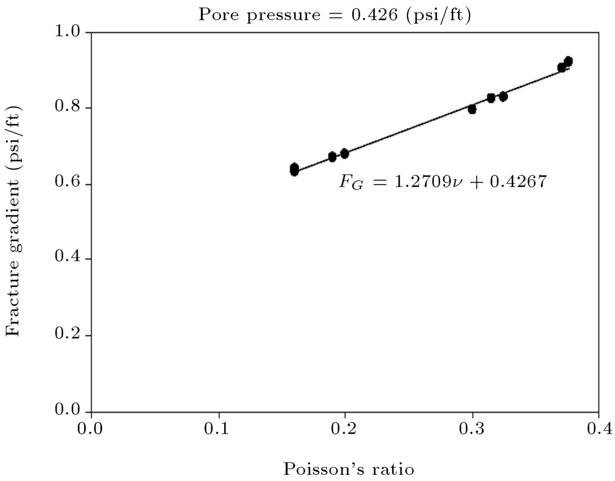

Figure 2. Fracture gradient determined based on Poisson's ratio at pore pressure gradient of 0.426 psi/ft.

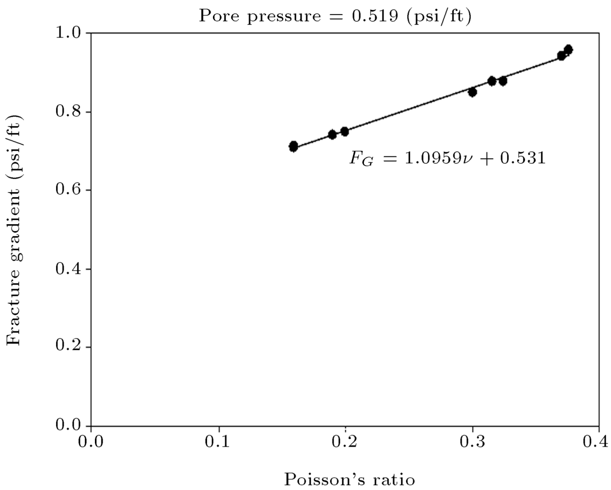

Figure 3. Fracture gradient based on determined Poisson's ratio at pore pressure gradient of 0.519 psi/ft.

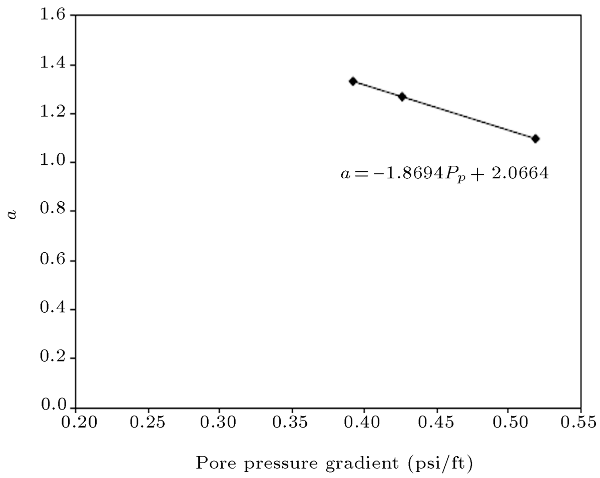

Figure 4. The relation between constant "a" and pore pressure gradient.

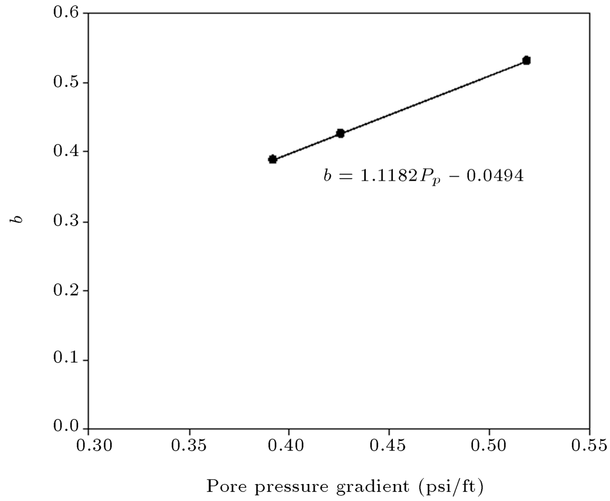

Figure 5. The relation between constant "b" and pore pressure gradient.

gradient as below:

$$FG = 0.52P_p + 0.6118. \tag{8}$$

For different net pressures, the required equation for obtaining the fracture gradient can be represented using Equations 4, 5 and 7 as below:

$$FG = 0.52P_p = 0.53 = (0.0816 \times 10^{-3} P_n). \tag{9}$$

Using Equation 8, a graph can be applied for a quick estimation of the fracture gradient.

Calculation of Stress Gradient and Fracture Gradient Using Well Test Data

Before the hydraulic fracturing job, well tests, such as the min-fracture test or step rate test are conducted for estimation of the fracture gradient.

The step rate test starts with a low flow rate injection and increases gradually in steps, until achieving the final flow rate, which is equivalent to the break pressure of formation. Each step starts when the pressure in the last step is stable. Figure 6 shows a typical step rate test, which in the increment of flow rate versus time, is drawn. The bottom hole pressure versus flow rate is shown in Figure 7 and so are two lines based on the change of the steps of the points [13]. The intersection of the two line (point PG) shows pressure fracture development, which is called fracture propagation pressure. This pressure is the pressure at which the fracture starts to propagate. The intersection of the second line with the pressure axis (point Pc), where the flow rate is zero, is the closure pressure [14]. In an acidizing operation in well B5 of the Bangestan reservoir, a step rate test has been carried out [15]. The results are shown in Table 5.

Table 5. The result of step rate in well B5 of Bangestan reservoir.

Friction Pressures (psi)	Pressure@perforations (psi)	Time (Min.)	Rate of Injection (bbl/min)	Fluid Volume (gal)
620	8600	5.95	20	5000
903	8650	5.4	22	5000
677	8700	8.66	22	8000
1072	8750	7.62	25	8000
813	8770	9.5	25	10000
1242	8770	8.5	28	10000
1061	8780	9.5	30	12000
1693	8800	8.16	35	12000
1270	8790	23.81	35	35000
467	8550	5.4	35	8000

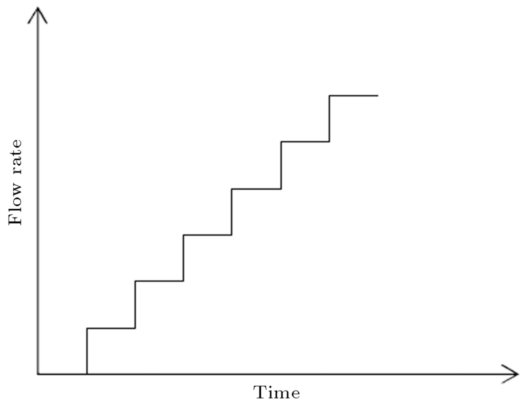

Figure 6. Curve line of injection flow rate based on time in a step rate test.

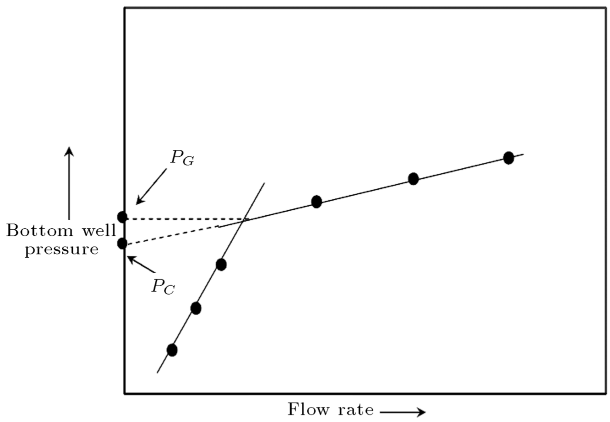

Figure 7. Curve line of well bottom pressure in each step based on step rate test (Economides, Oligney, and Valko, 2002).

In order to determine the stress gradient, the pressure at perforations based on the injected flow rate at each step is drawn in Figure 8. In this figure the dip of each point at pressure 8750 (psi) is changed. This point is considered as the in-situ stress, from the

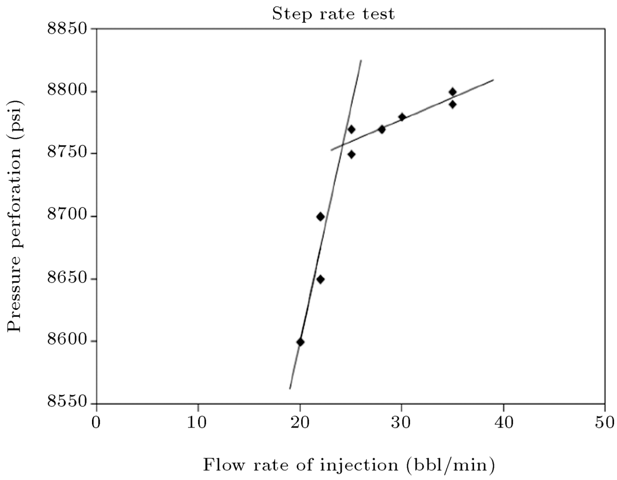

Figure 8. Profile of step rate result in well B5 Bangestan reservoir.

initial step of perforations (at depth of 3450 m), to determine the stress gradient. To obtain the stress gradient, the above pressure is divided by the depth, which is calculated as:

$$\sigma_h = \frac{8750}{3450 \times 3.281} = 0.77 \qquad \text{(psi/ft)}.$$

For comparison of the results from Equation 2 with the test results, firstly the pore pressure gradient is calculated and then using Equation 2, the stress gradient is estimated. Based on the pressure values reported, the reservoir pressure in well B5 at a depth level of 3350 (m) is equivalent to 5150 (psi). Hence, the pressure gradient in this well is:

$$P_p = \frac{5150}{3373 \times 3.281} = 0.47 \qquad \text{(psi/ft)}.$$

Therefore, from Equation 2 the stress gradient is obtained as:

$$\sigma_h = (0.5294)(0.47) + (0.5176) = 0.77 \qquad \text{(psi/ft)}.$$

This indicates a good agreement between the results obtained from Equation 2 and that of a well operation test.

ANALYSIS OF STRESS PROFILES IN THE STUDIED WELLS

In the previous section, the stress gradient for a given depth of Bangestan reservoir rocks is shown to be estimated by Equation 2. This equation is used to obtain the stress profiles in the studied wells. The pore pressure gradient at a given depth is calculated using the equation below:

$$p_p = \frac{p_{\text{datum}} + 3.281 G_F (D - D_{\text{datum}})}{D}. \tag{10}$$

The datum depths for the Ilam and Sarvak formation (top and bottom) are 3350 m and 3750 m from sea level, respectively. The average pressure at base depth for various layers is shown in Table 6. The reservoir oil and water gradients are approximately 0.33 (psi/ft) and 0.48 (psi/ft), respectively.

After the above calculations for the stress gradient with relation to depth and in order to select the potential layers for hydraulic fracturing, the stress profiles in each well together with the porosity and water saturation percentage profiles are plotted. The results are given below.

Well B2

Figure 9 shows the stress, porosity and water saturation profile and the type of lithology, with respect to depth, in this well. From the analysis and interpretation of this figure, the following result can be obtained:

- Layers A and B: These layers are tight and massive limestone with low porosity and, because of high stress cannot be considered as having potential for hydraulic fracturing.
- Ilam formation (Layers C1, C2 and C3): These layers have low stress, a low percentage of water saturation and high porosity and include barrier layers with high stress in the upper and lower formations (Layers A, B at the top and Layer D at the bottom portions), which are suitable for hydraulic fracturing operations. The barrier layers can help to produce hydraulic fracturing with a controlled height.
- Sarvak formation (Layers E1, E2 and E3): Because of low porosity, the high percentage of water saturation and low stress, this layer is not a suitable candidate for hydraulic fracturing. This operation may cause water production.
- Lower Sarvak formation (Layer H): A low percentage of water saturation, good porosity and a low stress regime in this layer makes it a good nominee for hydraulic fracturing.

Well B3

The respective profile for this well from which the following conclusions can be made is shown in Figure 10.

- Layers A and B: They have low porosity and high stress and, hence are considered as a barrier.
- Layer D: This layer has high stress and is considered as a barrier for the above operation.
- Top Sarvak formation: This formation in Layers E1, E2 and the upper part of E3 has a relatively good to intermediate porosity and a low percentage of water saturation with low stress, thus can be considered as a good hydraulic fracturing candidate layer.
- Layer F: This layer has high stress and is considered as a barrier for hydraulic fracturing.
- Lower Sarvak formation (Layers G and H): These layers in well B3 consist of a relatively good to moderate porosity with low saturation and also low stress. Therefore, they are good candidates for hydraulic fracturing. As a conclusion, in this well, the Ilam formation is a suitable candidate for the above purpose.

Well B4

Figure 11 shows the profiles of stress, porosity and percentage of water saturation with lithology in various layers in this well. The analysis and discussion of these profiles are summarized as below:

- Layers A and B: These layers consist of high stress and very low porosity and they can be considered as a barrier beds.

Table 6. The average pressure in base depth for various layers in Bangestan reservoir.

	Layers Pressure (psi)		
Section	**Ilam Fm**	**Top of Sarvak Formation**	**Bottom Sarvak Formation**
Eastern	5100	4600-5000	4700-5010
Central	5190-5400	4700-5150	5040-5600
Western	4810-5040	-	5650

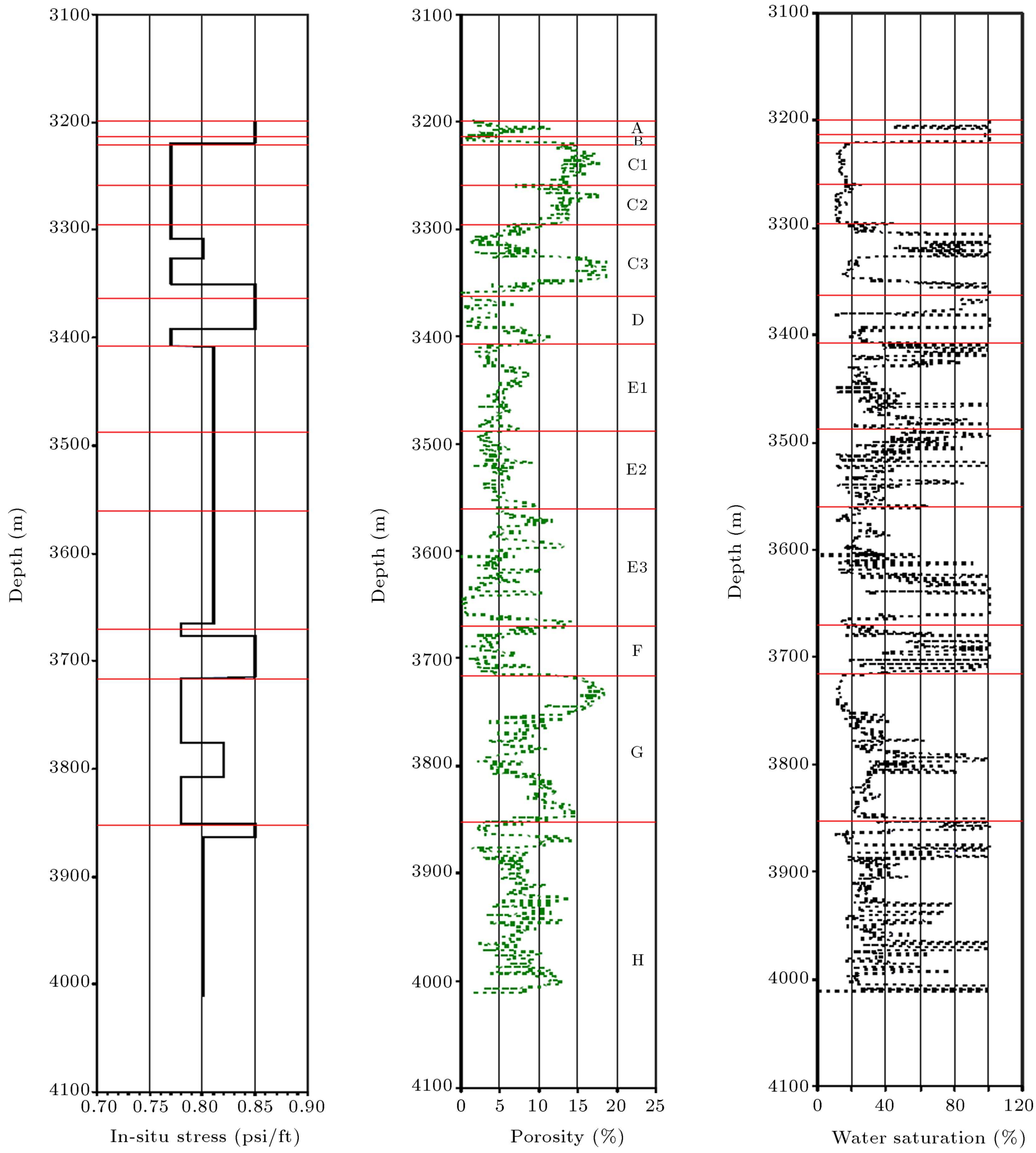

Figure 9. Profile of stress, porosity and water saturation of well B2, Bangestan reservoir.

- Ilam formation: This formation consists of low stress, but the percentage of porosity in Layers C1 and C2 is relatively good and is low in Layer C3. The water saturation in Layers C1 and C2 is low and in Layer C3 is high. Hence, the hydraulic fracturing operation in this formation may cause the penetration of fracturing into Layer C3, which may produce water in the well.

- Layer D: This bed consists of high stress and low porosity and is considered as a barrier in this well.

- Upper Sarvak formation: This formation is similar to the Ilam formation, i.e. the stress is low, but the porosity in Layers E1 and E2 is good to moderate and in E3 is low. The percentage of water saturation in Layers E1 and E2 is good to moderate and in Layer E3 is low. The percentage of water saturation in Layers E1 and E2 is relatively low and in the Layer E3 is high. Therefore, similar to the lower formation in this well, the hydraulic fracturing in this formation may cause penetration into Layer E3 and increase the rate of water production.

- Layer F: This layer has high stress, low porosity and hard rock and acts as a barrier in this well.

- Lower Sarvak formation: Layers G and H consist of a high percentage of water saturation and moderate porosity. But Layer I has lower water saturation and moderate to good porosity. Layer I can be penetrated into Layers G and H, and it causes the rate of water production to be increased.

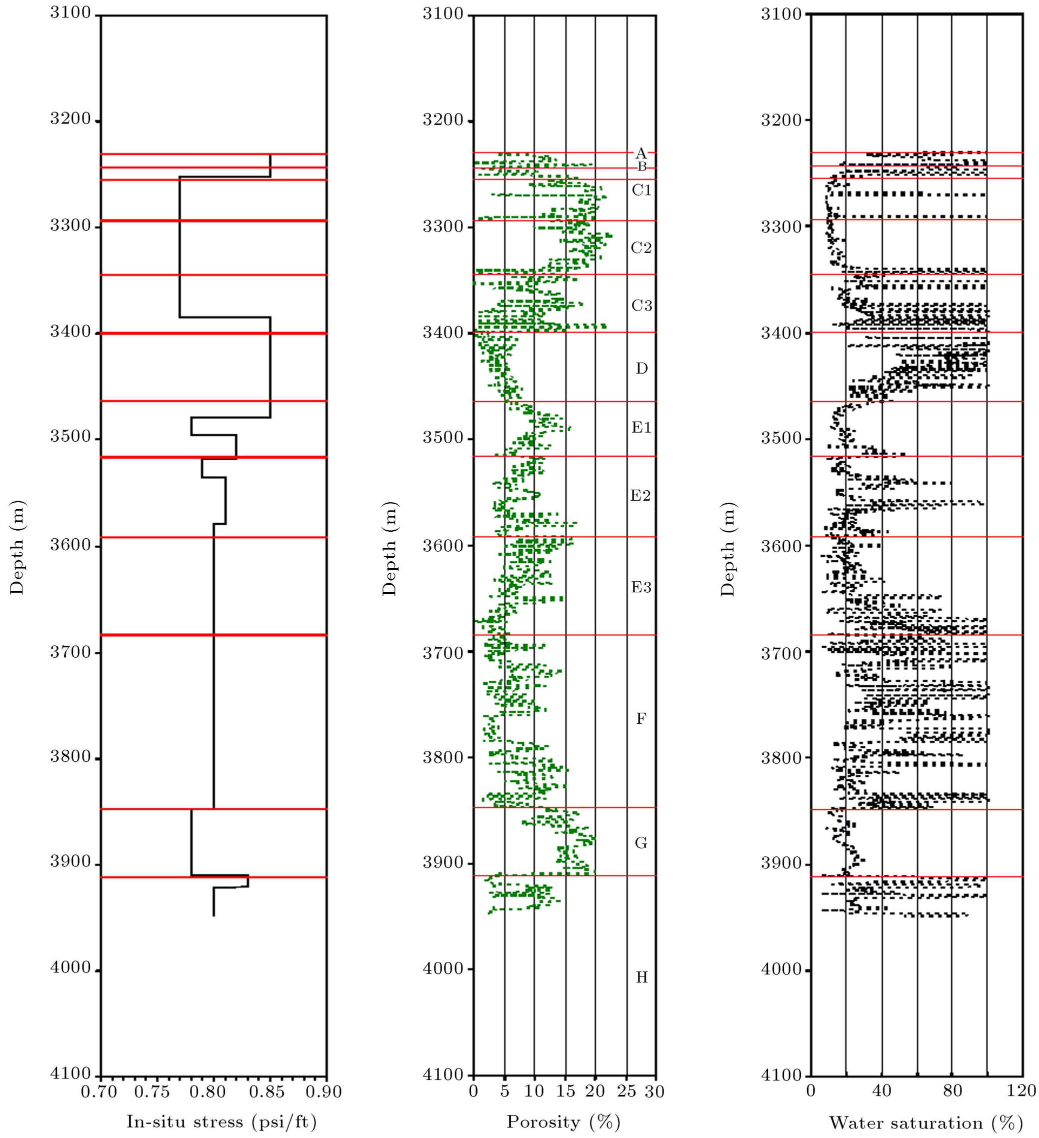

Figure 10. Profile of stress, porosity and water saturation of well B3, Bangestan reservoir.

Well B1

Figure 12 shows the profiles of stress, porosity and the percentage of water saturation together with the lithology at various depths. The interpretations of these profiles are given here:

- Layers A and B: These two layers have high stress and very weak porosity and act as a barrier.
- Ilam formation: This limestone formation consists of low stress with very good porosity and low saturation. As a result, the Ilam formation in this well is a good candidate for hydraulic fracturing.
- Layer D: This layer, similar to Layers A and B, consists of a high stress profile and is a good layer for hydraulic fracturing.
- Upper Sarvak formation: This formation in well B1 consists of a good to moderate porosity, low stress and a low percentage of water saturation. Hence, it can be considered as a second alternative, after the Ilam formation, for hydraulic fracturing.
- Layer F: This layer has high stress and is considered as a barrier.
- Lower Sarvak formation: The stress in this formation is high and the percentage of porosity is moderate to low with a high percentage of water saturation. Therefore, it cannot be chosen as having suitable potential for hydraulic fracturing.

RESULTS AND DISCUSSION

From a laboratory measurements point of view, the mechanical properties of reservoir rock are mea-

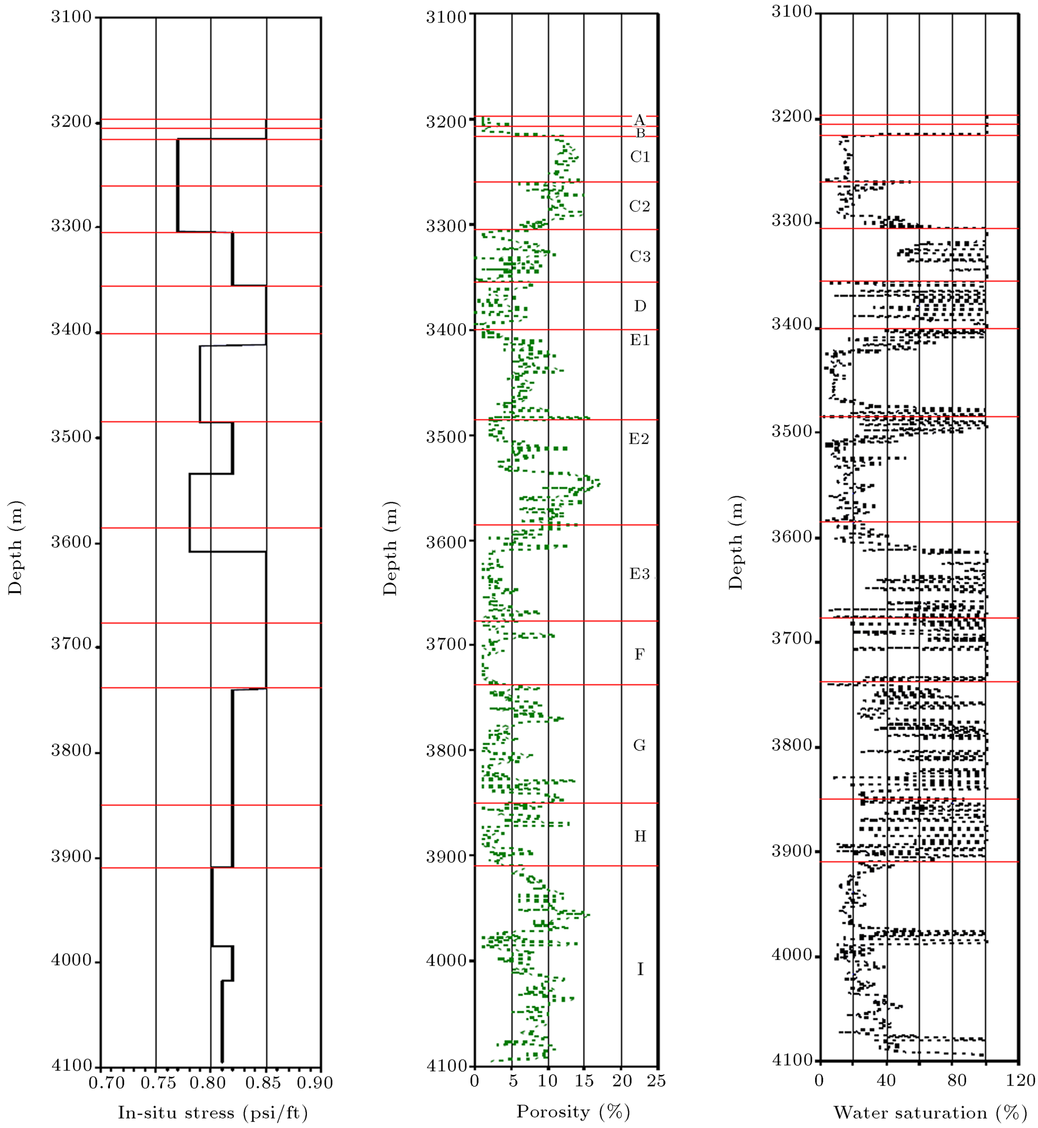

Figure 11. Profiles of stress, porosity and water saturation in well B4, Bangestan reservoir.

sured and the mathematical correlation equations are used for converting these properties into stress and fracture gradients. Besides, the well operation test with the aim of estimating the stress gradient has taken place. One of the most important parameters of designing hydraulic fracturing is to determine the depth of fracturing which is related to minimum horizontal stress. In case of a single existing fracture, the minimum pressure for creating the fracture horizontal stress pressure needed to close the fracture is called the closure stress.

In successful hydraulic fracturing, the internal pressure must be higher than the minimum horizontal stress to prevent the fracture being closed. The pressure fracture is the pressure which is obtained due to fracture rocks and this fracture which comes from the pressure fracture will remain open by minimum horizontal stress.

In an acidizing operation in well B5 of the Bangestan reservoir, a step rate test has been carried out for calculation of the stress and fracture gradients. In order to determine the stress gradient, the pressure at perforations based on the injected flow rate at each step is drawn in Figure 8.

The analyses of stress profiles, porosity and water saturation have been studied in four wells (B2, B3, B4, B1) in the Bangestan reservoir. The results indicate that, in these wells, the Ilam formation (Layers C1, C2) is a good candidate for hydraulic fracturing. Beside, Layer C3 has high water saturation. Hence, the hydraulic fracturing operation in this formation may cause the penetration of fracturing into Layer C3. Layer F, in well B3, has high stress and is considered

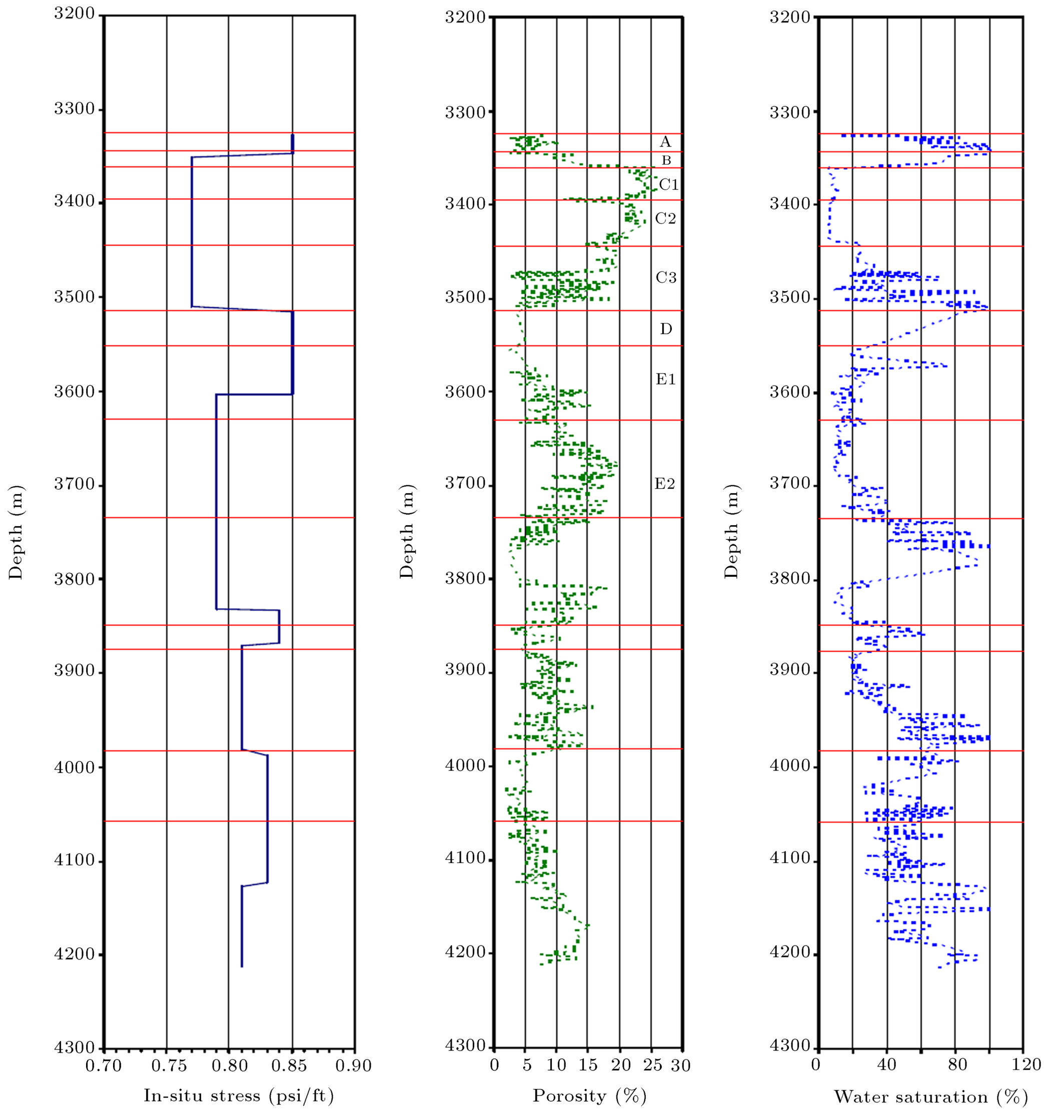

Figure 12. Profiles of stress, porosity and water saturation in well B1, Bangestan reservoir.

as a barrier for hydraulic fracturing. The lower Sarvak formation Layers G, H, in well B3, consist of relatively good to moderate porosity with low saturation and also low stress. Therefore, these layers are good candidates for hydraulic fracturing. As a conclusion, in this well, the Ilam formation is a suitable candidate for a hydraulic fracturing operation.

CONCLUSION

- The rock mechanics tests that have been carried out on various samples of the Bangestan reservoir in the Ahwaz oil field indicate that the Poisson ratio of rocks in this reservoir is approximately 0.32.
- Considering $\nu = 0.32$ and the overburden pressure of 1.1 (psi/ft), the Eaton equation can be modified as Equation 2 for the Bangestan reservoir.
- The measurement and calculation of the fracture gradient in this field shows that the fracture gradient in the Bangestan reservoir for a net pressure equivalent to 1000 (psi), can be obtained from Equation 8 and, more generally, from Equation 9.
- To estimate the stress gradient and fracture gradient of a reservoir with a given Poisson ratio and pressure, Figures 1 to 6 can be used.
- The Step rate test in well B5 in the Bangestan reservoir shows that the gradient stress across perforations in this well is 0.77 (psi/ft), which is in good agreement with that calculated from Equation 2.
- Calculation of the stress gradient, percentage of water saturation and porosity in some of the wells in the Bangestan reservoir indicate that, in these wells, the Ilam formation (especially Layers C1, C2) is a good candidate for hydraulic fracturing.

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NOMENCLATURE

D	depth (ft)
D_{datum}	datum depth (ft)
F_G	fracture gradient (psi/ft)
G_F	fluid gradient of reservoir (psi/ft)
P_p	pore pressure gradient (psi/ft)
P_{datum}	datum pressure (psi)
P_n	net pressure (psi)
a, b	constant values
σ_h	minimum horizontal stress gradient (psi/ft)
σ_v	overburden stress gradient (psi/ft)
ν	poisson ratio (dimensionless)

S I Metric Conversion Factors

Hz = frequency

psi $\times 6.894757E+00$ =k Pa

ft $\times$ 3.048 E-01 = m

gal $\times 3.785412E-03 = \text{m}^3$

bbl $\times 1.589873E-01 = \text{m}^3$

μs = microsecond

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