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A Simulation Study of the Factors that Impact Gas-Oil Ratio (GOR) Behavior in Liquid-Rich Shale (LRS) Reservoirs

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Abstract

The behavior of producing gas-oil ratio (GOR) in unconventional reservoirs like liquid-rich shales (LRS) and conventional reservoirs differ. This is mainly due to major disparity in the permeability ? ultra-low in unconventional reservoirs in comparison to that in conventional (higherpermeability) reservoirs. The ultra-low permeability and porosity of shales, among other factors contribute to the complex fluid flow mechanisms in these plays. Therefore, there is a need for a good comprehension of the physics of flow in liquid-rich shale reservoirs. This paper particularly investigates how various factors, ranging from critical gas saturation to compaction affect producing gas-oil ratio behavior in liquid-rich shale (LRS) reservoirs. Ten different moderately volatile and highly volatile (near-critical) oil fluid compositions were considered. Compositional reservoir simulations for a period of 30 years were run on a base case multi-fractured horizontal well (MFHW) model for each fluid type. Results showed that the different factors had varying impacts on the production performance and GOR behavior of LRS reservoirs ? some more influential than others. Also, the fluid type, whether moderate or highly volatile oil, play a major role in determining how producing gas-oil ratios (GOR) behave in a LRS reservoir. A proper understanding of unconventional reservoir production mechanisms is necessary for reliable reserves estimation, production forecasting and improving oil recovery. This work contributes to this mission and provides a better understanding of the performance of liquid-rich shale plays.

Index terms— unconventional resources; gas-oil ratio; liquid rich shales; volatile oil; production forecasting.

1 I. Introduction

iquid-rich shales (LRS) are shale rocks that contain high value oil and gas. Typical examples are the Eagle Ford play in Texas and the Bakken play in North Dakota, among several others. In recent times, LRS reservoirs have become viable sources of oil and gas production. Initially, the ultra-low permeability and porosity of shale formations made producing economic volumes of oil and gas from these reservoirs difficult. However, technological advancement in the form of multi-fractured horizontal wells (MFHW) has significantly improved production from these plays.

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In oil reservoirs, when reservoir pressure drops below the bubble point, solution gas evolves. The degree of undersaturation, production mechanisms of the reservoirs, fluid PVT properties and other factors determine the rate of solution gas production. Gas-oil ratio refers to the ratio of the volume of gas that evolves out of solution to the volume of produced oil at standard conditions. In the work by Beliveau (2004), there are three major factors that impact gas-oil ratio (GOR) performance -gas-oil relative permeability curve, the presence of initial gas cap and the strength of any associated aquifer. In the cases considered in this study, gas caps were absent and there were no associated acquifers. Solution gas drive is the primary drive mechanism in liquid-rich shale reservoirs.

This work studies the impacts of factors and parameters like bottomhole pressure, critical gas saturation, degree of undersaturation, fracture halflengths, compaction, rock compressibility, etc. on producing gas-oil ratio (GOR). Whitson and Sunjerga (2012) demonstrated through the simulation of multifractured horizontal wells (MFHW) that producing GOR can be strongly dependent on the bottomhole pressure (BHP) when permeability is very low (approximately less than 0.001md). Also, Behmanesh et al. (2015) studied the GOR behavior of a multi-fractured horizontal well (MFHW) with constant BHP during linear flow. Jones Jr. (2016) investigated variations in the producing gas-oil ratio behavior of MFHW in tight oil reservoirs.

With a better knowledge of the behavior of producing GOR in liquid-rich shale (LRS) plays, forecasting of solution gas production can be possible. Yu (2014) presented a method for forecasting solution gas production based on predicted oil production. He proposed a specialized plot based on a linear relationship between the logarithm of a well's cumulative gas-oil ratio (GORcum) and cumulative oil production (Np). Makinde and Lee (2016) modified this method by considering a power law relationship between these two variables. Also, Makinde and Lee (2016) presented a different approach to forecasting production from LRS reservoirs -Principal Components Methodology (PCM), based on the statistical data-driven technique of principal components analysis. PCM was also used in another study by to forecast solution gas production from LRS reservoirs.

2 II. Reservoir model Description

A 5000 ft horizontal well, with 20 hydraulic fractures spaced 250 ft apart was modeled. The fractures have half lengths of 150 ft and are all infinitely conductive. Fracture width of 2 ft was used to make simulation easier.

Fracture permeability was correspondingly reduced to keep the product of width and permeability (of fractures) at an appropriate level. Reservoir models with the same fracture conductivity but different fracture widths yield similar results (Alkouh et al., 2012).

A commercial compositional simulator was used to simulate production with ten different reservoir fluids (moderately and highly volatile oils). Fluids 3 and 4 are near-critical fluids. The well produced for 30 years at a minimum bottomhole pressure constraint of 1000 psia. Logarithmically-spaced local grid refinement (LS-LGR) was used to model pressure drop and fluid flow as accurately as possible. Figure 1 shows a pictorial representation of the reservoir model. Tables 1 and 2 show the reservoir data and the reservoir fluid compositions used.

Table **??** Fluid Compositions LRS reservoirs under consideration in this work are shale volatile oil reservoirs (fluids are moderately and highly volatile oils). Solution gas drive is the primary drive mechanism in shale volatile oil reservoirs. In this study, the reservoir is initially undersaturated i.e., the initial reservoir pressure is greater than the saturation pressure (bubble point pressure). At this time, production is mainly driven by the bulk expansion of reservoir rock and oil. When reservoir pressure drops below the bubble point, expansion of gases dissolved in oil provide most of the reservoir drive energy. Illustrations of gas-oil ratio history, reservoir pressure and gas saturation with time for one of the fluid samples in the basecase scenario are shown in Figures 2, 3 and 4. Figure 3 is a semi-log plot of the gas-oil ratio history to enable proper visibility of the various critical points of production mechanism of shale volatile oil reservoirs. In Figure 2, it is evident that the reservoir pressure declines rapidly before reaching the bubble point. Beyond the bubble point, the rate of decline slows due to the evolution of gas. The six critical stages of the GOR history of a well in a shale volatile oil reservoir driven by solution gas drive mechanism shown in Figure 3 are briefly explained below:

Reservoir pressure is greater than the saturation pressure (bubble point pressure). Here, no free gas exists in the formation and the producing GOR is approximately equal to the initial solution GOR (i.e., approximately constant GOR);

The gas saturation starts to increase forming a "GOR hill". Though gas is not mobile yet, there is an increase in the amount of gas released from oil from point 2 to 3 and an increasing gas saturation;

Due to the continuous rapid decline in pressure above the bubble point, gas solubility decreases from point 3 to 4;

The critical gas saturation is reached and gas can flow;

At this point, the reservoir pressure decreases below the bubble point, gas evolution accelerates and producing GOR starts to increase rapidly;

Producing GOR is still increasing after 30 years. For shale oil reservoirs, the producing GOR may continue to increase for even longer due to ultra-low permeability of shales and other contributing factors.

The producing GOR for all the fluid samples (basecases) are compared and shown in Figure 5. They all have a similar trend but generally, the more volatile the fluid, the higher the producing GOR throughout the production period. The gas produced when reservoir pressure drops below the saturation pressure in an oil reservoir remains immobile until it reaches a certain threshold. This threshold is called the critical gas saturation. At and above the critical gas saturation, gas become mobile and begin to flow towards the wellbore. Critical gas saturations of 5% (basecase), 10%, 15% and 20% were considered to determine the impact on the performance of MFHW in shale volatile oil reservoirs. the impacts of critical gas saturation on producing GOR (semi-log plots) for Fluids 1, 4, 7 and 10. Generally, the higher the critical gas saturation, the lower the producing GOR with time. There is also a delay in the rise of producing GOR with time, as critical gas saturation increases. With increasing critical gas saturation, there is a slight dip in producing GOR after the period of constant GOR. The further away the fluid is from the critical point, the more pronounced the dip is. Fluid 4 is a near-critical fluid, therefore, the dip in producing GOR after the constant GOR period, is nearly absent in these cases. This can be observed in Figure 6. Year 2017 C IV.

Critical Gas Saturation The wells under consideration here produce at constant flowing bottomhole pressure (BHP). The lower the BHP below the saturation pressure, the more the drawdown. Cases of different constant flowing BHPs were considered including when the BHP is equal to the bubble point pressure. The basecase is a constant flowing BHP of 1000 psi. The lower the constant flowing BHP, the higher the producing GOR except for the cases of 100 psi and below for the least volatile oil -Fluid 10, 250 psi and below for other moderately volatile oils and from 500 psi and below for highly volatile oils. In these cases, the producing GOR towards the end of the production time decreases with lesser constant flowing BHP due to the large drawdown which led to the production of gas reaching a peak quickly and declining with time till the end. The more volatile the fluid, the quicker the producing GOR reaches a peak and starts to decline even at higher flowing bottomhole pressures. When the constant flowing BHP is equal to the bubble point pressure, the producing GOR remains constant throughout the production. There is a mild increase in producing GOR with time for the case of BHP equal to 2000 psi (slightly lower than the saturation pressure in most of the cases). Figures **??** and 9 show the effects of bottomhole pressure (BHP) on producing gas-oil ratio (semi-log plots) for Fluids 1, 4, 7 and 10. The degree of undersaturation is the difference between the initial reservoir pressure and the saturation (bubble point) pressure. Cases with initial reservoir pressures of 5000 psi (basecase), 4500 psi, 4000 psi and 3500 psi were studied. The lower the degree of undersaturation, the quicker the reservoir pressure will reach the saturation pressure. Therefore, with decreasing degree of undersaturation, the producing GOR increases with time and vice versa. Correspondingly, there is a delay in the initial rise of producing GOR with increasing degree of undersaturation and vice versa. Likewise, the higher the degree of undersaturation, the lesser the height of the ”GOR hill”. Moreover, the higher the degree of undersaturation, the longer the period (at the start of production) where the producing GOR remains constant i.e., the period where the producing GOR is approximately equal to the initial solution GOR. Figures 10 and 11 show the effects of the degree of undersaturation on the producing GOR (semi-log plots) for Fluids 1, 4, 7 and 10. Generally, the trends are similar in all cases regardless of the volatility of the volatile oil fluid sample considered. For the case with drainage area of approximately 275 acres (drainage area 2 -Figure 13), boundary-dominated flow (BDF) is not reached in some instances due to low permeability and the relatively large unstimulated reservoir volume (USRV). This is the situation especially when moderately volatile oil reservoir fluids are present. For highly volatile oils, BDF is observed because of higher oil mobility (less viscosity in comparison to less volatile oils) towards the regions close to the stimulated reservoir volume (SRV). This BDF is followed by a late linear (or compound linear) flow when production from the unstimulated reservoir volume (USRV) dominates. The trend of producing GOR is generally the same till boundary-dominated flow (as observed on the rate-time diagnostic plots) is reached. According to Jones Jr. (2016), for multi-fractured horizontal wells (MFHW), producing GOR rises during BDF because of declining pressures at the midpoint between fractures and corresponding increase in average gas saturation in the drainage area. This phenomenon is observable in our results. After boundary-dominated flow, there is a steeper rise in producing GOR with reducing reservoir drainage area. With increasing reservoir drainage area, it takes longer to reach boundary-dominated flow (BDF is not even observed in some cases depending on the volatility of the reservoir fluid). Therefore, the larger the reservoir area, the milder the rise in producing GOR with time. Due to the higher mobility of highly volatile oils, production may later be dominated by the regions beyond the SRV (for larger reservoir drainage areas), leading to the decline of producing GOR towards the end of the production period (30 years in our cases).

3 VIII. Fracture Half-Length

Fracture half-length is the distance from the wellbore to the outer tip of a fracture propagated from the well by hydraulic fracturing or penetrated by the well. It is an important completion parameter for shale reservoirs. For these analyses, fracture half-lengths of 50 ft, 100 ft, 150 ft (basecase), 200 ft, 250 ft, 300 ft and two other cases where the fracture half-lengths are of different lengths, i.e. uneven configuration of fracture lengths were considered. These two special cases were compared separately to the basecase to determine their impact on production performance. Figures 18 to 24 show the pictorial representations of each case apart from the basecase (already shown in Figure 1). There is a delay in the rise of producing GOR with reducing fracture half-lengths. The shorter the fracture half-length, the lesser the gas saturation at the fracture faces. Also, the further away the bubble point of the volatile oil is from the initial reservoir pressure (degree of undersaturation), the lower the height of the ”GOR hill”. This is more noticeable for cases with highly volatile oils. Therefore, the higher the degree of undersaturation and the shorter the fracture half-lengths, the lower the height of the ”GOR hill”. The highly volatile oils are closer to the critical point (two fluids are nearcritical), therefore in most of these instances, the ”GOR hill” is very low or absent during the production period.

Reservoir model with uneven configuration 1 has three of its fractures with half-lengths of 300 ft whereas the reservoir mel with uneven configuration 2 has four of its fractures with half-lengths of 300ft. Therefore, the well with uneven configuration 2 generally produce more oil than the well with uneven configuration 1. They both produce more oil than the well with the basecase configuration (uniform fracture half-lengths of 150 ft).

The producing GOR generally follows the same trend as already discussed in the previous paragraph. Fracture permeability is a measure of the ease with which fluids flow through the connecting pore spaces of fractured rocks. In other words, it is a measure of the ability of fractured rocks to transmit fluids. Fracture permeability is directly proportional to the dimensionless fracture conductivity, as seen in Equation 1 below.?? ???? = ?? ð ??”ð ??” ?? ð ??”ð ??” ???? ð ??”ð ??” , (**1**)

where FCD is the dimensionless fracture conductivity, kf is the fracture permeability, wf is the fracture width, k is the formation permeability and xf is the fracture half-length. In the analyses of the impacts of fracture permeability on well performance, fracture permeabilities of 5 md, 10 md, 20 md, 60 md, 80 md and the basecase -41.65 md were considered. With reducing fracture permeability, there is a delay in the increase of gas saturation at the fracture faces. Consequently, there is a delay in the formation of the ”GOR hill” (delay in the initial rise of producing GOR) and longer period of constant GOR. The reverse is the case with increasing fracture permeability.

4 X. Fracture Spacing

Even though closer fracture spacing (more fracture stages) requires a higher completion cost per well, it eventually means better drainage of the SRV within a shorter period (Makinde, 2014). The closer the fracture spacing, the larger the cumulative oil production. For highly volatile oils, cumulative oil production starts to reduce with closer fracture spacing later during production because of high gas saturation.

The effect of fracture spacing on producing GOR is quite significant. The closer the fracture spacing, the more rapid the critical gas saturation is reached. This therefore results in higher producing GOR with time as fracture spacing reduces. For highly volatile oils, high gas saturation can result in very high producing GOR towards the end of the production period.

For the special cases with uneven fracture spacing, the well with uneven configuration 2 (15 fracture stages) has closer fracture spacing in comparison with the well with uneven configuration 1 (12 fracture stages). This can be observed in Figures 31 and 32. Therefore, though fracture spacing is non-uniform and since the well with uneven configuration 2 generally has closer fracture spacing than that with uneven configuration 1, it produces more oil (larger cumulative oil production). Oil produced in both cases is lower than the oil produced from the well with basecase configuration (Figure 1). This is because they both have lesser fracture stages than the basecase (20 fracture stages). The impact on producing GOR is like earlier discussed scenarios. The closer the fracture spacing, the higher the producing GOR with time. Figures 33 and 34 show the effects of fracture spacing on producing GOR (semi-log plots) for Fluids 1 and 10.

5 XI. Rock Compressibility

the cumulative oil production and vice versa. At much higher rock compressibility values, there is a possibility that high gas saturation may impede oil production later during production, especially for highly volatile oils.

The impact of rock compressibility on producing GOR (for the values considered) is not significant. The trends are generally similar and the higher the rock compressibility, the lower the producing GOR with time. It is likely that the impact of high gas saturation may alter the pattern of producing GOR at much higher rock compressibility values. Figures 35 and 36 show the effects of rock compressibility on producing GOR (semi-log plots) for Fluids 1, 4, 7 and 10. For the basecase reservoir model, compaction was not included. However, here, the effects of compaction on shale volatile oil well production performance were investigated. Cases of weak compaction (constant rock compressibility of 4*10-6 psi-1), mild compaction (constant rock compressibility of 20*10-6 psi-1) and strong compaction (with the use of pressure-dependent compaction table shown in Table **??**) were examined in the reservoir model. All the results were compared together with the basecase (no compaction) results.

As reservoir pressure depletion occurs during production, compaction increases the pressure on the rocks (net confining pressure) due to the weight of the overlying sediments (overburden) and the pore fluid pressure decreases. This increase in net confining pressure can lead to collapse of pore spaces and thus, efficient expulsion of hydrocarbons can take place. Though compaction leads to reduction of porosity and permeability, strong compaction can enhance oil recovery significantly. The stronger the compaction, the larger the cumulative oil production. Weak compaction may lead to slight reduction in cumulative oil production (slightly smaller oil production than the basecases). This is because the slight reduction in porosity and permeability caused by weak compaction overrides the major compaction effect in this instance. Mild compaction leads to more oil production than the basecases and strong compaction results in the largest cumulative oil production. A similar result was obtained by Khoshghadam et al. (2015) in their study of the impact of confined pore spaces on liquid-rich shale reservoir performance.

Weak compaction has little or no effect on producing GOR with time. For most cases, it is approximately identical to the basecases (no compaction). Mild compaction results in the reduction of producing GOR with time as more oil is produced in this case. For the cases with strong compaction, producing GOR remains approximately constant throughout the production period. This is because strong compaction keeps the average reservoir pressure so high that it never depletes beyond the saturation pressure. Also, large quantities of oil were

225 produced due to strong compaction. Figures 37 to 40 portray the impacts of compaction on producing GOR (semi-log plots) and cumulative oil production for Fluids 1, 4, 7 and 10. [1]

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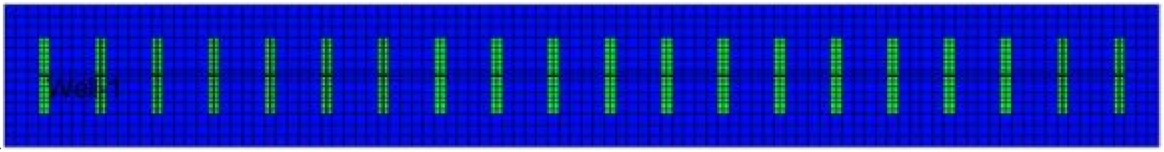

Figure 1: LAFigure 1 :

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Permeability	0.001 md
Porosity	0.06
Reservoir Temperature	250°F
Initial Reservoir Pressure	5,000 psia
Depth to top of formation	10,000 ft
Reservoir Thickness	250 ft
Corey Relative Permeability Exponent	2.5
Critical gas saturation, S_{gc}	0.05
Residual saturation of oil (gas/oil displacement), S_{org}	0.2

Figure 2: Figure 2 :

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	Fluid 1	Fluid 2	Fluid 3	Fluid 4	Fluid 5	Fluid 6	Fluid 7	Fluid 8	Fluid 9	Fluid 10
Components	Composition (%)	Composition (%)	Composition (%)	Composition (%)	Composition (%)	Composition (%)	Composition (%)	Composition (%)	Composition (%)	Composition (%)
CH_4	58.77	58.07	61.82	53.47	49.43	49.96	48.78	51.93	44.42	41.52
C_2H_6	7.57	7.43	7.91	11.46	7.28	6.44	6.24	6.64	9.52	6.12
C_3H_8	4.09	4.16	4.42	8.79	8.02	3.48	3.49	3.71	7.30	6.74
I-C_4H_{10}	0.91	0.96	1.02	-	2.31	0.77	0.81	0.86	-	1.94
N-C_4H_{10}	2.09	1.63	1.74	4.56	3.61	1.78	1.37	1.46	3.79	3.03
I-C_5H_{12}	0.77	0.75	0.80	-	1.80	0.66	0.63	0.67	-	1.51
N-C_5H_{12}	1.15	0.80	0.86	2.09	1.79	0.98	0.67	0.72	1.74	1.50
C_6H_{14}	1.75	1.14	1.21	1.51	2.32	1.49	0.96	1.02	1.26	1.95
C_{7+}	21.76	22.59	17.59	16.92	22.41	33.50	34.98	30.78	30.98	34.82
CO_2	0.93	2.32	2.47	0.90	0.16	0.79	1.95	2.08	0.75	0.13
N_2	0.21	0.15	0.16	0.30	0.87	0.18	0.13	0.13	0.25	0.73
	Highly Volatile Oils					Moderately Volatile Oils				
GOR, scf/bbl	3,024	3,043	4,081	3,967	2,561	1,806	1,755	2,128	1,873	1,513
API	63.5	63.0	63.5	64.9	65.2	49.2	49.1	46.8	49.7	50.6
Oil FVF, bbl/stb	3.56	3.55	-	4.81	3.26	2.23	2.19	2.42	2.32	2.10

Figure 3: Figure 3 :

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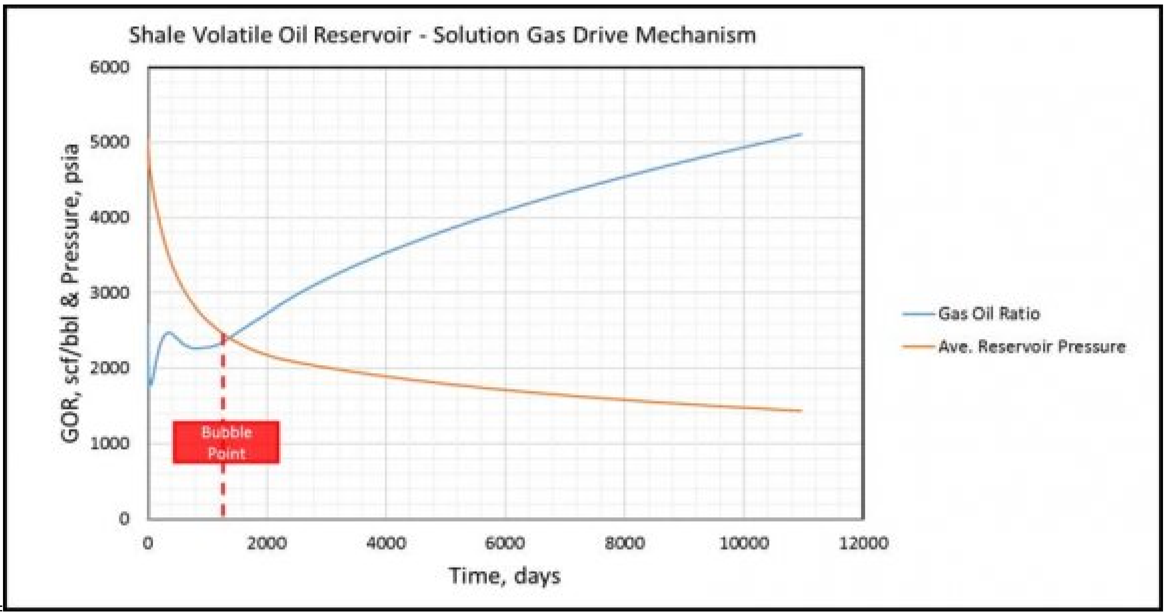

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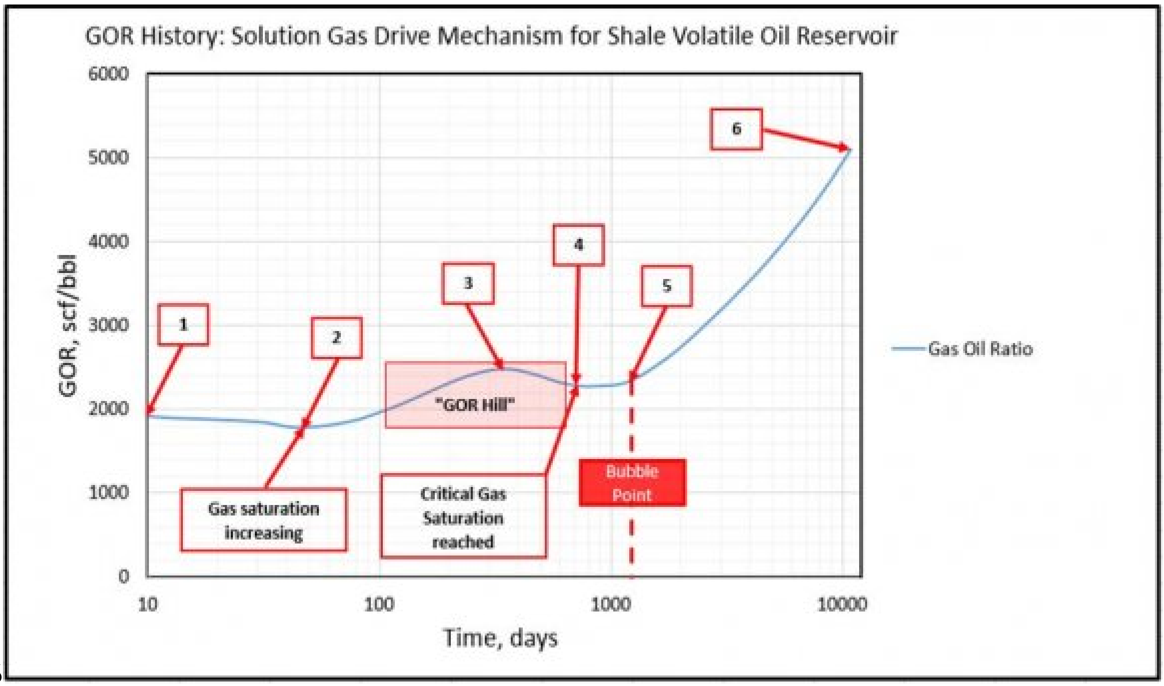

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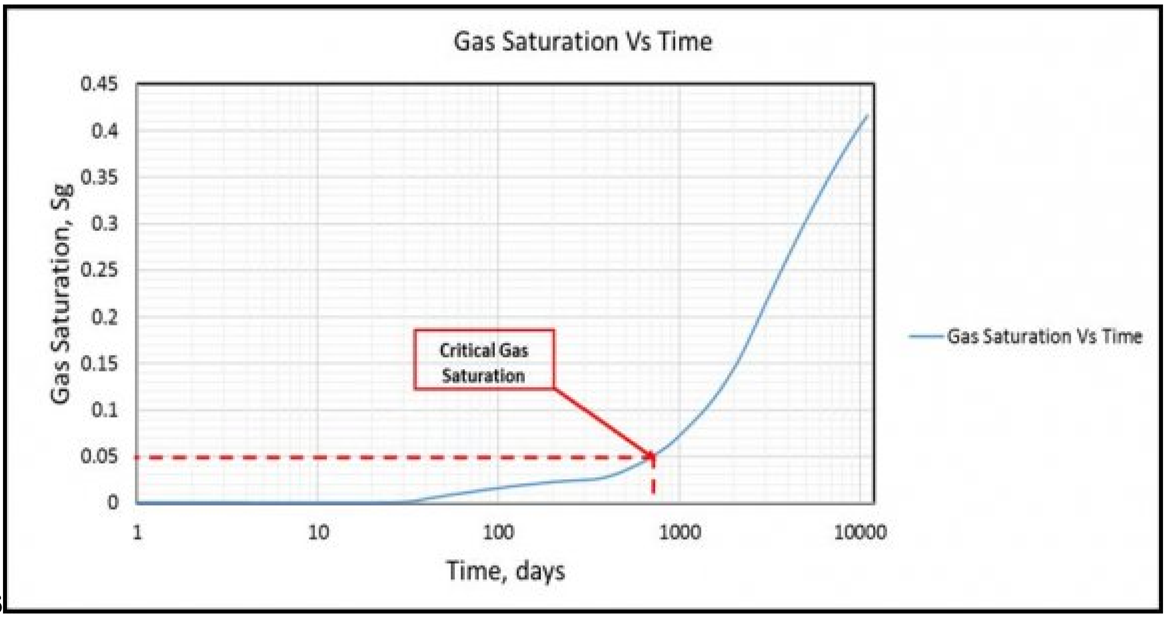

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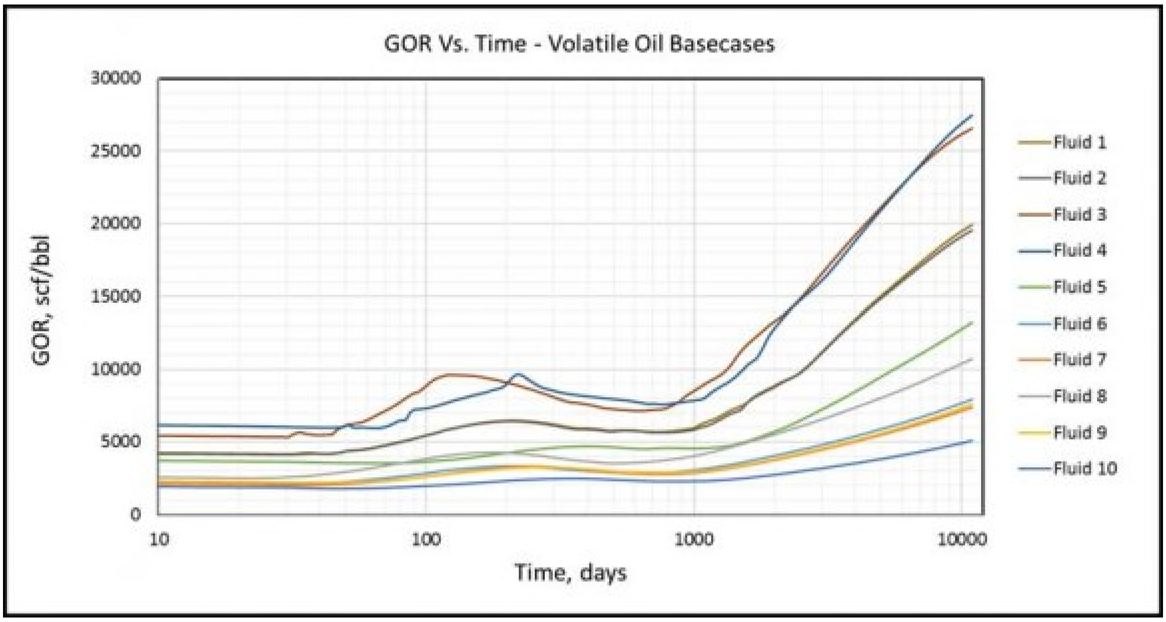

Figure 7:

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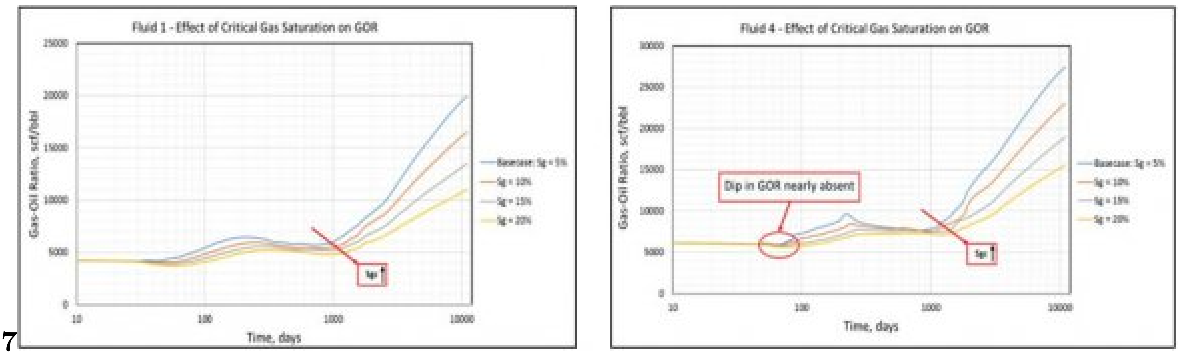

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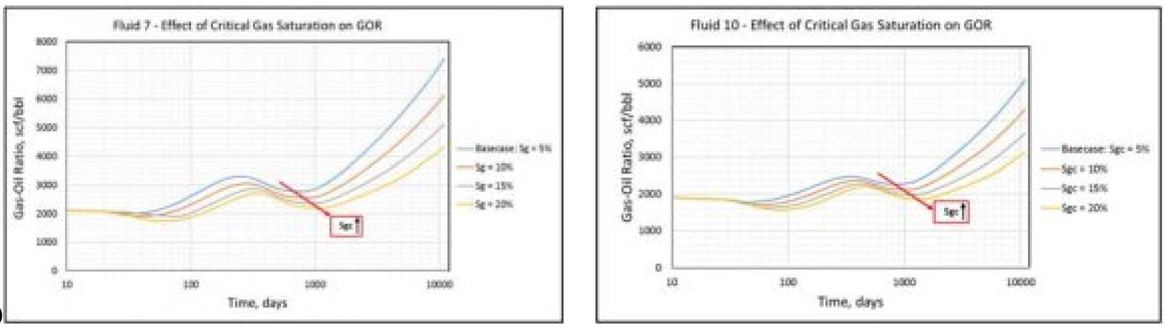

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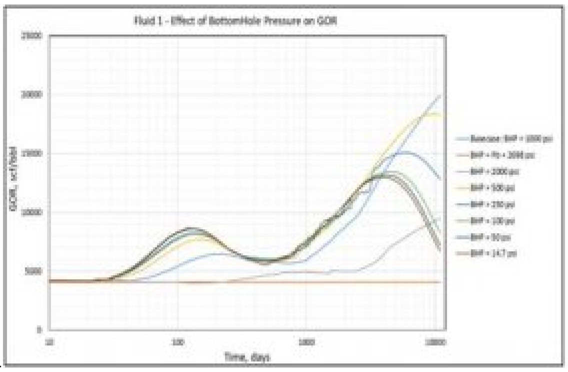
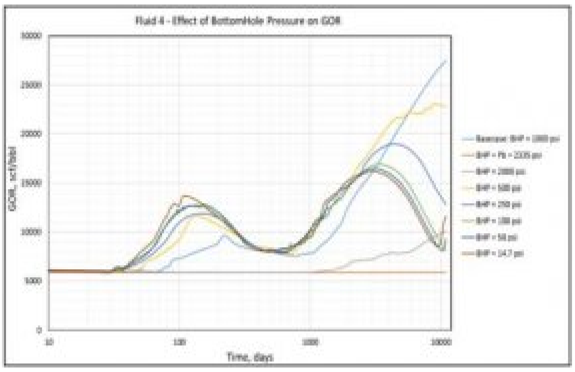
1011 



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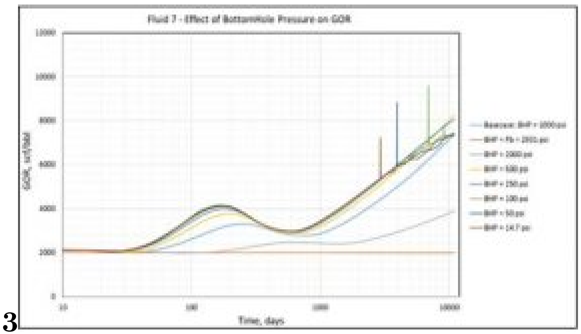
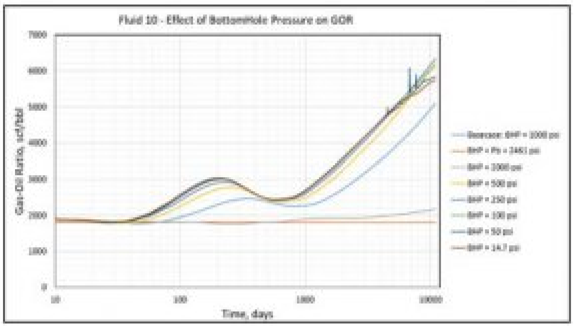
1213 



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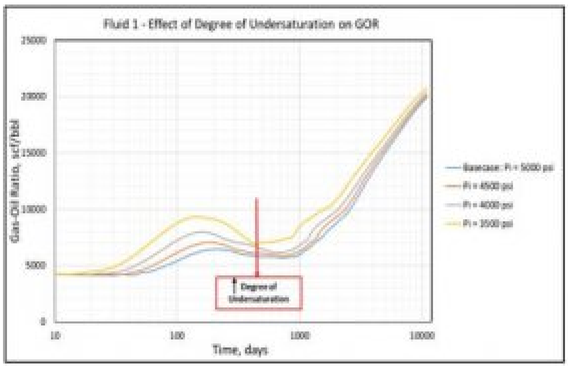

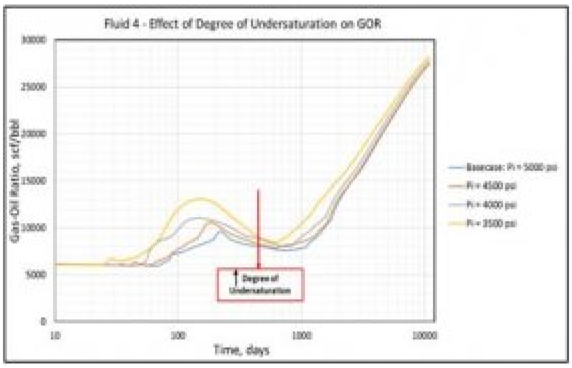

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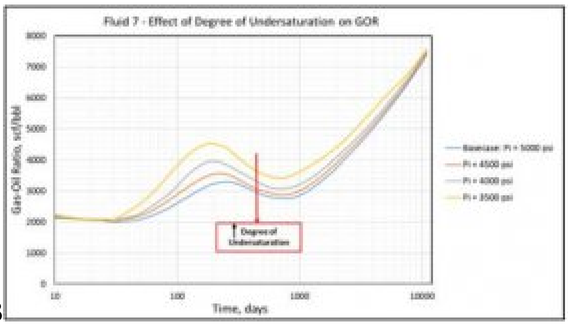
1415161718 

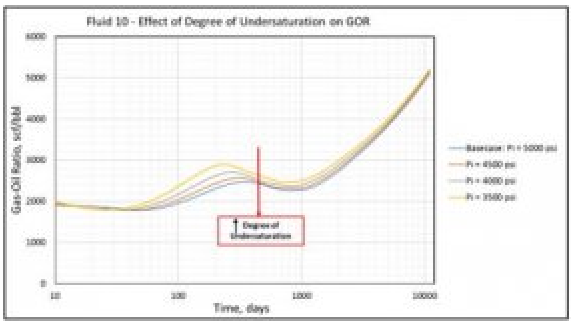
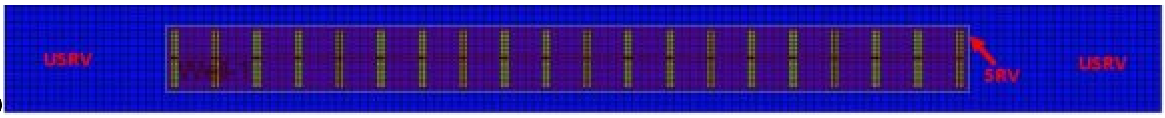


Figure 13: Figure 14 :Figure 15 :Figure 16 :Figure 17 :Figure 18 :

19 

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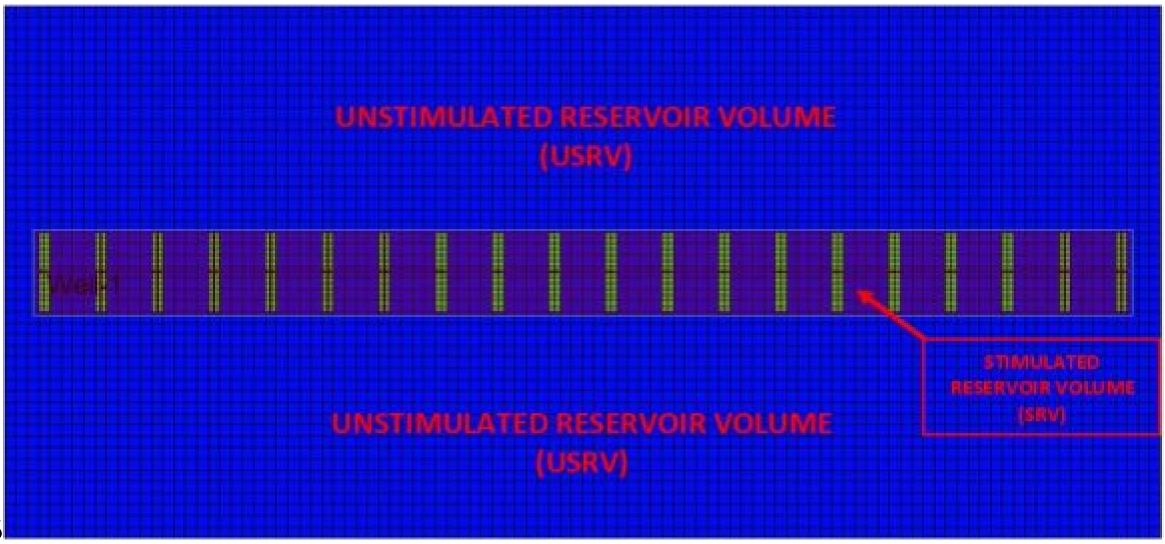
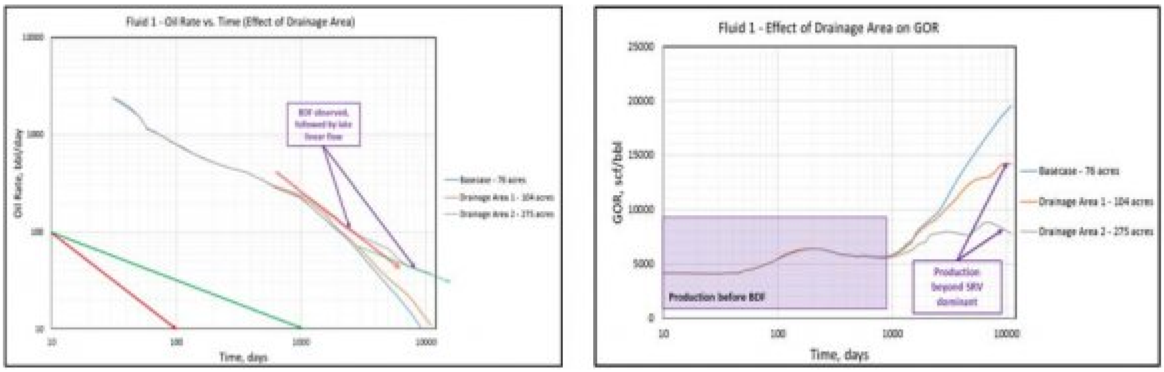
25 



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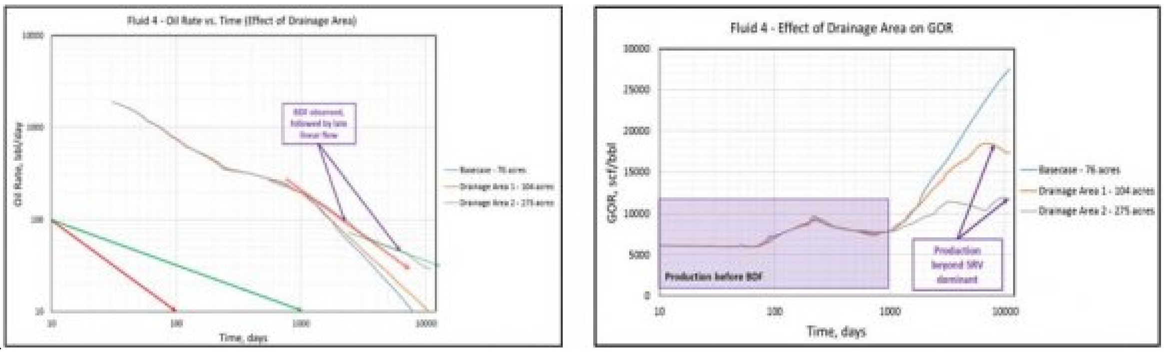
27293031 

Figure 17: Figure 27 :CFigure 29 :Figure 30 :Figure 31 :

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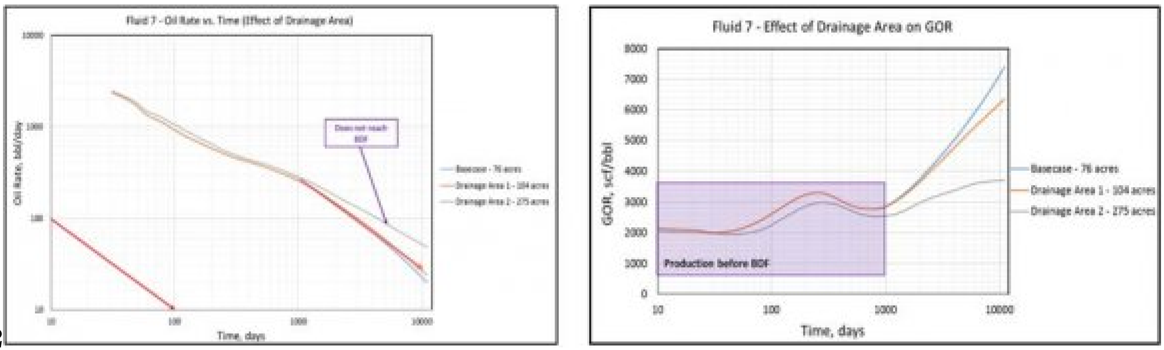

Figure 18: Figure 33 :CFigure 32 :

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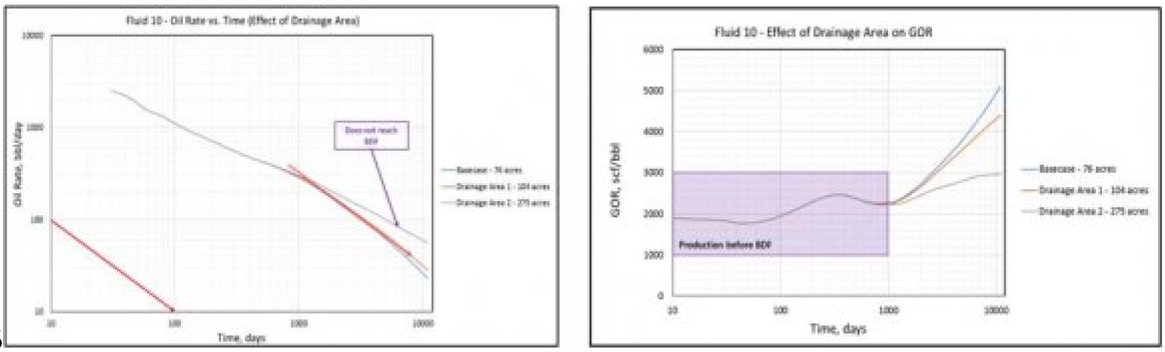

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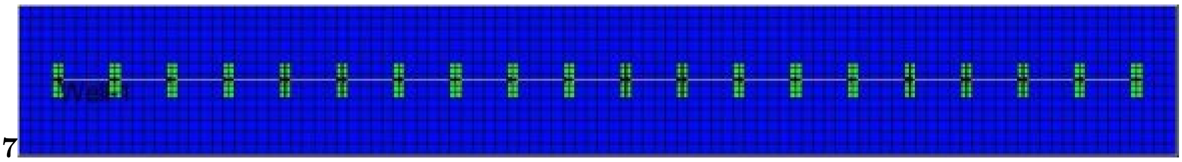

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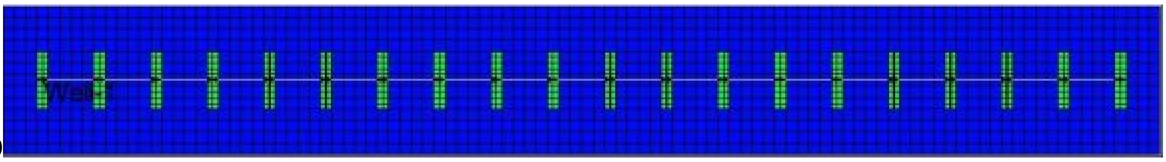
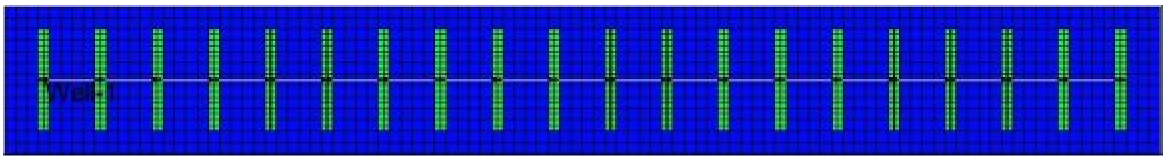


Figure 21: Figure 38 : 2017 CFigure 39 :



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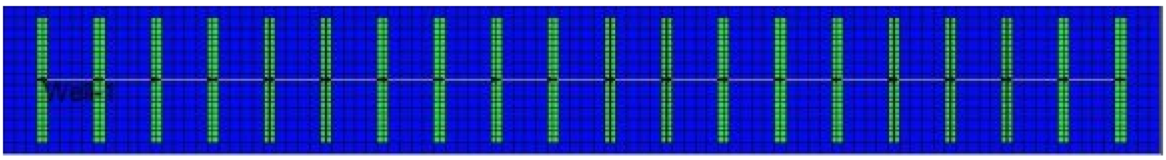

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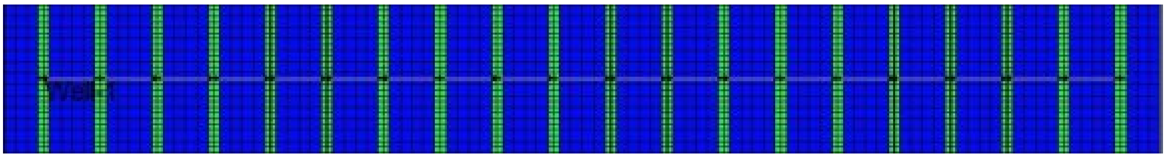

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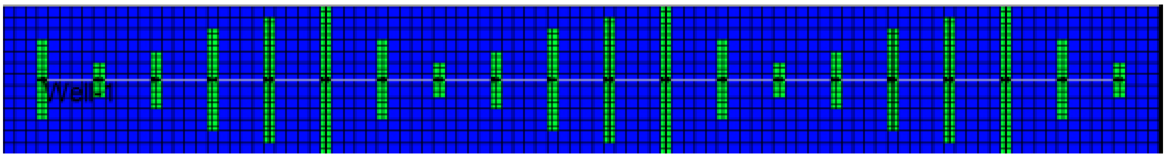

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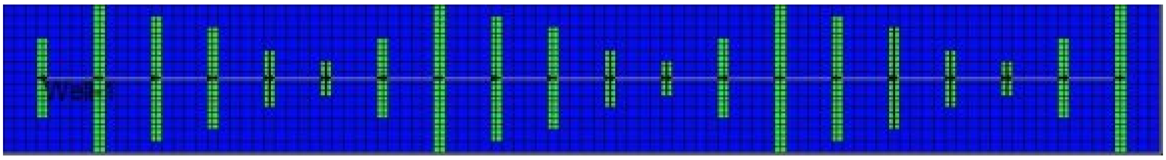

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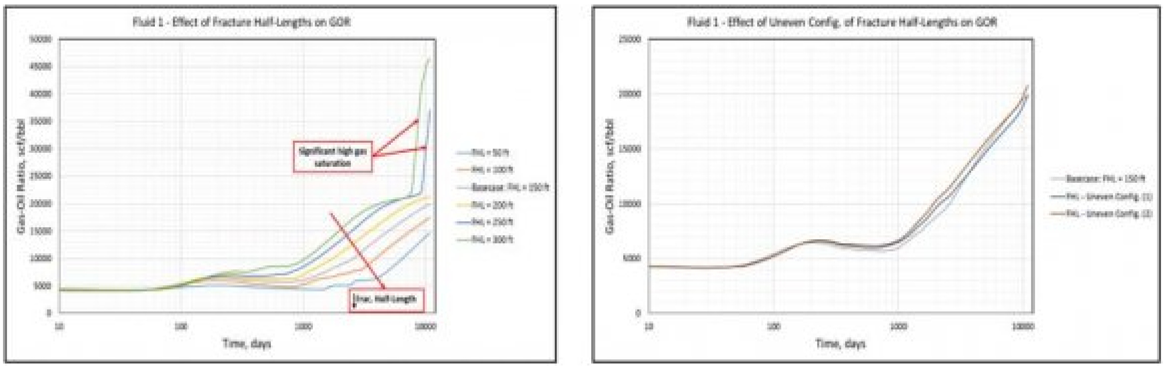

Figure 27:

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[Note: © 2017 Global Journals Inc. (US) A Simulation Study of the Factors that Impact Gas-Oil Ratio (GOR) Behavior in Liquid-Rich Shale (LRS) Reservoirs Global Journal of Researches in Engineering ( ) Volume XVII Issue II Version I 28 Year 2017 C]

Figure 28: Table 1

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