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Recovery from Thin Net Pay in Gas Fields

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Abstract

Recovering gas from gas fields involves a proper understanding of the underlying reservoir geology, drive mechanism, permeability and permeability thickness amongst other factors that influence hydrocarbon recovery and productivity potential. The cost of exploiting reservoirs that have lower recoveries than expected can result in huge economic implications. The world is gradually shifting its focus from conventional sources of hydrocarbon to unconventional sources where permeability can be in nanodarcies. Gas reservoirs in high permeability formations are usually exploited as they can give a great return on investment but when the permeability is low, decisions are often made against exploiting them. If these reservoirs are adjacent to high permeability zones, they may or may not contribute to recovery or to the net pay and this will depend on factors such as permeability contrast, transmissibility, production rate and the thickness fraction of such layers.

Gas reservoirs containing zones/layers/beds with horizontal and vertical permeability much lower than the rest of the reservoir may be laterally extensive containing huge volumes of recoverable hydrocarbon but are nonetheless counted as 'non-pay' because of their low permeability. It is assumed that their permeability is so low that they will not contribute significantly to recovery. This project will explore when these low permeability gas bearing zones adjacent to high permeability zones should be included in evaluations of net pay and when they should be ignored. It quantifies the contribution of low permeability beds to gas production in gas reservoirs by cross flow as a function of the characteristics of the surrounding reservoir and the low permeability layers themselves.

To better simulate the conditions of a gas bearing formation of low permeability adjacent to a high permeability formation, the reservoir was divided into two regions: top and bottom. The top region (high permeability) was assumed to have a permeability of 100 mD while the lower region's permeability was varied from 100 mD to 0.000001 mD. The effects of varying the lower permeability on the pressure response, gas production and ultimate recovery were studied as well as its impact on the GIIP estimated from material balance. Then, the effect of the thickness of a shaly or low permeability layer was studied. Shale thickness fraction was varied from 0.1 to 0.9 as a fraction of the entire reservoir thickness and the effect on the reservoir's pressure response and gas recovery was studied. The transmissibility effect between two high permeability zones was studied to see how closely it would simulate a reservoir with permeability contrast. The relationship between transmissibility and permeability was established. Finally, the effect of varying production rate and grid dimensions on reservoir's pressure response, gas production and recovery over a field life of 20 years was studied.

The results show that 0.01 mD is cutoff for net pay inclusion of low permeability zones. Also, in a high permeability reservoir adjacent to a low permeability formation, maximum gas production occurs at 0.3 shale fraction and recovery factor declines for shale fractions greater than 0.3. Shaly fraction here refers to the fraction of the entire reservoir thickness occupied by the low permeability zone. The transmissibility and permeability contrast study revealed that areas with very low transmissibility factor separating two high permeability zones will not behave as if the lower layer was entirely a low permeability zone. The production rate of a homogeneous reservoir has no effect on the predicted value of the GIIP obtained from pressure data but for a heterogeneous reservoir, constant rate production data would give a better prediction of GIIP than constant BHP data.

Introduction

Many gas reservoirs contain huge volumes of gas in regions where the average permeability is in microdarcies. These very low permeability regions may or may not be adjacent to regions with high permeability. Gas production from gas bearing formations with high permeability adjacent to formations of low permeability often lead to the lower permeability region being neglected because such permeability is not always thought to contribute to net pay. Thus a proper understanding is needed if recovery is to be made from such regions.

"Production data solely from these intervals is extremely limited, so confirming that production and ultimate recovery from these resources is challenging" (Baillie and James-Romano, 2010). To properly understand the dynamics of gas production from such layers, several reservoir cases have to be tested with respect to varying permeability contrast, transmissibility and changing shale thickness and their effects on the reservoir pressure response, recovery and GIIP prediction. Sylvester et al., (2005) showed that the value of GIIP of a field changes as proper understanding of the field through reservoir modelling is achieved. Even though the early production profile gives reservoir engineers insight into the life of a field, low permeability reservoirs show a slow initial recovery and slow decline due to recharge of the existing high permeability region. Russell and Prats, (1962) were the first to analytically show the performance of a well in a bounded layered reservoir with cross flow suggesting that such delay is not undesirable but simply improves the capacity of the field to be exploited in the future. Thus early production and pressure data is not usually sufficient to adequately quantify the hydrocarbon potential of a reservoir.

"Data quality is an important issue in material balance calculations but yet uncertainty abounds and are found in production data, measured PVT properties and average reservoir pressures" (Carlos and Jose, 2007). In simulation, additional uncertainties lie in the choice of grid dimensions as well as numerical interpolations. Much of the analysis done in this paper relies on the pressure data which means that the results obtained will only be as good as the PVT data and how the average reservoir pressure is calculated.

In this study, an investigation was made on a simple model reservoir with two regions: a high permeability layer and a low one. In some simulations, the lower region's permeability was varied and other cases the thickness. The study focuses on how the permeability contrast in a reservoir can lead to an accurate prediction of the cutoff values for permeability to maximize recovery. It varied the transmissibility in a homogeneous reservoir to see the effect on the pressure response, gas production and recovery. Changes in the thickness of the lower region with changing permeability was also analyzed.

Methodology

This study uses data from an Eclipse example data file for a simple gas field. The GIIP for the gas field was estimated first by analytical calculations of the volumetric GIIP and material balance and then from the pressure decline data calculated by Eclipse 100 (Schlumberger, 2010). To get the GIIP, a G_p vs $1/B_g$ plot was made assuming B_g varies linearly with pressure for pressure values not on the table with a linear regression using B_g vs the pressure data used in the Eclipse model.

Volumetric Calculation

$$\mathrm{GIIP} = \frac{\mathrm{V}\times(1-\mathrm{S_{wc}})\times\emptyset}{\mathrm{B_{gi}}} \quad \text{(Eq. 1)}$$

$$\mathrm{GIIP} = \frac{3.53\times10^{11}\times(1-0.18)\times0.2}{0.005136} = 11.3\ \mathrm{Tscf} \quad \text{(Eq. 2)}$$

Material Balance

Material balance is an alternative expression for the law of conservation of mass. The volumetric calculation gave a GIIP of 11.3 Tscf. To get the $1/B_g$ plot, an analytical calculation was made and the results plotted as shown in **Fig. 3:**

$$G_p = G\left(1 - B_{gi}\left(\frac{1}{B_g}\right)\right) \quad \text{(Eq. 3)}$$

$$G_p = G - GB_{gi}\left(\frac{1}{B_g}\right) \quad \text{(Eq. 4)}$$

where G_p is the cumulative gas produced and $(1/B_g)$ the reciprocal of the gas formation factor. A numerical solution was made using the data from Eclipse which gave a GIIP of 11.3 Tscf. The numerical solution was compared to the analytical solution and it gave a good match with both GIIP at 11.3 Tscf. The reservoir simulation was modelled using Eclipse 100 (Schlumberger, 2010). To get the B_g for the G_p vs $1/B_g$ plot, values from the pressure data generated by Eclipse and the PVT data were input into equation 5. Equation 5 is the linear interpolation used

$$B_{gx} = B_{gj} + \left(\frac{P_{j+1}-P_x}{P_{j+1}-P_j}\right)\left(B_{gj+1} - B_{gj}\right) \quad \text{(Eq. 5)}$$

where B_{gx} is the unknown gas formation volume factor, B_{gj} for the immediate lower gas formation volume factor on the PVT Table, P_{j+1} and P_j stand for the higher and lower gas pressure from the PVT Table respectively sandwiching the reservoir pressure P_x corresponding to the unknown gas formation factor, B_{gx}.

Recovery Factor

"The recovery factor from a gas reservoir is primarily a function of the abandonment pressure and permeability thus lowering the abandonment pressure will result in higher recovery factors" (Ikoku, 1984). The reservoir was divided into 2 regions: top and bottom and the recovery factor from each zone was analyzed as well as the whole reservoir for all cases studied: varying permeability contrast, transmissibility, shale thickness and constant rate vs constant BHP. The formulae used are shown below

$$\text{Recovery in top region} = \frac{\text{Cumulative gas produced in top region}}{\text{GIIP in top region}} \quad \text{(Eq. 6)}$$

$$\text{Recovery in bottom region} = \frac{\text{Cumulative gas produced in bottom region}}{\text{GIIP in top region}} \quad \text{(Eq. 7)}$$

$$\text{Total recovery} = \frac{\text{Total gas produced}}{\text{GIIP in reservoir}} \qquad \text{(Eq. 8)}$$

$$\text{Total recovery with abandonment pressure} = \frac{\text{Total gas produced}}{\text{GIIP in Reservoir} - \text{GIIP at abandonment}} \qquad \text{(Eq. 9)}$$

2D Simulation for a Homogeneous Reservoir

A gridsize of 10 × 1 × 10 was used to represent a reservoir of 10000 m × 10000 m × 100 m. The connate water saturation was 0.18. The initial reservoir pressure was 4000 psia at a gas formation factor of 0.005136 rcf/scf. Table 1 shows the reservoir and fluid properties while the Table 2 shows the PVT properties. Pressure data were generated from Schlumberger Eclipse 100 and the corresponding B_g from a linear regression. 20 years was used as the field life. Data from Table 1 and Table 2 were used in all the simulations.

Table 1–Reservoir, fluid properties and Eclipse sensitization parameters for homogeneous and heterogeneous reservoir models

Properties	Permeability, Transmissibility, Shale Thickness and Rate	Unit
Grid Dimensions (x × y × z)	10 × 1 × 10(additionally 10 × 1 × 100 for Rate case)	
Reservoir Dimensions (x × y × z)	10000 × 10000 × 100	m × m × m
Porosity	0.2	
Top Permeability	100	mD
Bottom Permeability	Varied (see Tables 4, 6, 7 for Permeability, Shale Thickness and Rate respectively). 100 mD for Transmissibility case	mD
Reservoir Thickness	100	m
Producer Location (x,y,z)	(10,1,1)	
Initial Reservoir Pressure	4000	psia
Rock Compressibility	0.0000028	1/psi
Water Compressibility	0.0000027	1/psi
Water Formation Volume Factor	1.013	rb/stb
Water Viscosity	62.43	cP
Gas Density	0.06054	Ib/ft^3
Water Density	62.43	Ib/ft^3
Gas Viscosity	see Table 2	cP
Gas Formation Volume Factor	see Table 2	rb/Mscf
Corey Parameter	2	

Table 2–PVT Properties

P (psia)	B_g (rb/Mscf)	μ_g (cP)
14.65	178.108	0.01429
400	9.0906	0.01461
600	6.0076	0.01487
800	4.4705	0.01519
1000	3.5532	0.01541
1500	2.3403	0.01611
2000	1.7467	0.01707
2500	1.401	0.01804
3000	1.1784	0.01905
3500	1.0254	0.0202
4000	0.9148	0.02136
5000	0.7676	0.02376

2D Simulation for Homogeneous Reservoir Models with Grid Refinement

A grid refinement study was done on the homogeneous model with dimensions of 20 × 1 × 20, 40 × 1 × 40 and 80 × 1 × 80. The pressure response in the reservoir was noted against the grid dimensions and the result tabulated in Table 3 below

Table 3–Grid Refinement Comparison (at BHP control)

Grid Cells	BHP (psia)	Initial Pressure (psia)	Final Pressure (psia)	Total Pressure Drawdown (psia)
10 × 1 × 10	100	2000	1013	994
20 × 1 × 20	100	2000	1025	982
40 × 1 × 40	100	2000	1031	976
80 × 1 × 80	100	2000	1034	973

2D Simulation for Heterogeneous Reservoir Model with Permeability Sensitization

The heterogeneous model was divided into two regions: the top region and bottom region, with the thickness of top region representing 30% of the total reservoir thickness. A constant permeability of 100 mD was assigned to the top region. The bottom region was then assigned permeability values ranging from 100 mD to 0.000001 mD as shown in Table 4. The pressure response, gas production and recovery were analyzed.

Table 4–Permeability Contrast Simulation Runs

Cases	Top Region Permeability (mD)	Bottom Region Permeability (mD)
1	100	100
2	100	10
3	100	1
4	100	0.1
5	100	0.01
6	100	0.001
7	100	0.0001
8	100	0.00001
9	100	0.000001
10	100	0

2D Simulation for Homogeneous Reservoir with Transmissibility Variation

The model was divided into 2 regions: the top region and bottom region, with the thickness of top region representing 30% of the total reservoir thickness. A constant permeability of 100 mD was assigned to the top region and bottom regions while the transmissibility between both regions was varied as shown in Table 5 below. The pressure response, gas production and recovery were analyzed.

Table 5–Transmissibility Simulation Runs

Cases	Transmissibility factor between both regions
1	100
2	10
3	1
4	0.1
5	0.01
6	0.001
7	0.0001
8	0.00001
9	0.000001
10	0

2D Simulation for Heterogeneous Reservoir with Shale Thickness Variation

The heterogeneous model was divided into 2 regions with the top region and bottom regions. A constant permeability of 100 mD was assigned to the top region. The bottom region was assigned a permeability of 0.0001 mD as seen in Table 6 and the thickness of the various regions was varied. This operation was repeated with lower region permeability case of 0.0001 mD, 0.00001 mD and 0.000001 mD. The pressure response, gas production and recovery were analyzed.

Table 6–Shale Thickness Simulation Runs

Cases	Lower Region Permeability (mD)	Top Region Fraction	Bottom Region Fraction
1	0.0001	1	0
2	0.0001	0.9	0.1
3	0.0001	0.8	0.2
4	0.0001	0.7	0.3
5	0.0001	0.6	0.4
6	0.0001	0.5	0.5
7	0.0001	0.4	0.6
8	0.0001	0.3	0.7
9	0.0001	0.2	0.8
10	0.0001	0.1	0.9

2D Simulation for Heterogeneous Reservoir with Rate Sensitization

The heterogeneous model was divided into 2 regions with the thickness of top region representing 10% of the total reservoir thickness. One case was analyzed at constant bottomhole pressure while the other case at constant rate as shown in Table 7 below. For the constant bottomhole pressure case, the permeability of the lower region was varied from 100 mD to 0.000001 mD. The same was done for the constant rate case. A constant production rate of 100 MMscf/d was used. This was found from simple calculations with the aim of maintaining a constant rate production over the entire permeability cases for the field life of 20 years. The pressure response, gas production and recovery were analyzed.

Table 7–Rate Sensitization

	Shale Thickness=0.9 (BHP Control)		Shale Thickness=0.9 (Rate Control)	
Bottom Region Permeability (mD)	Production Rate (MMscf/d)		Production Rate (MMscf/d)	
	Initial	After 20 years	Initial	After 20 years
100	340	237	100	100
0.000001	340	42	100	100
0	340	39	100	100

Results

Gridsize Refinement

To show the effect of grid refinement on the simulation result, several gridsizes were used: 10 × 1 × 10, 20 × 1 × 20, 40 × 1 × 40 and 80 × 1 × 80. The total pressure drawdown for a homogeneous reservoir of 100 mD permeability and initial reservoir pressure 2000 psia is shown in **Fig. 1.**

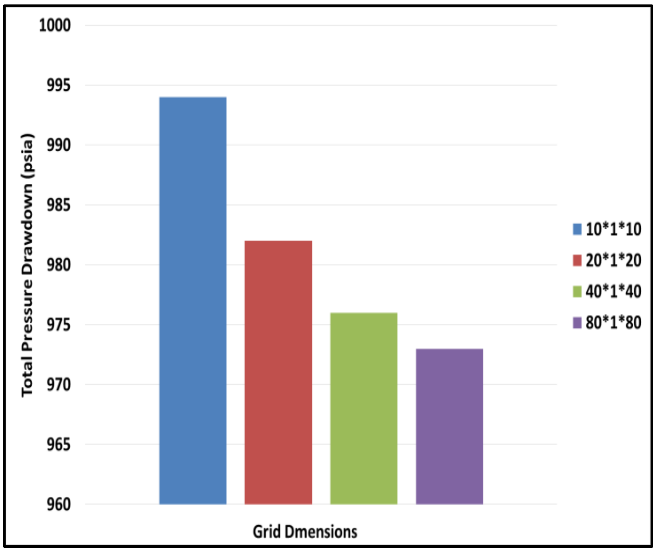


Fig. 1–Effect of grid refinement on total pressure drawdown

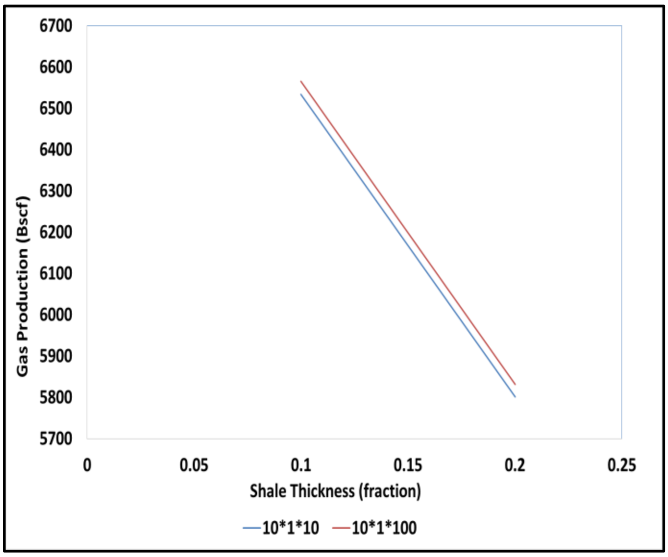


Fig. 2–Effect of grid refinement on gas production

Fig. 1 shows that an increase in the number of grid nodes results in a lower total pressure drawdown over the entire field life. 20 × 1 × 20, 40 × 1 × 40 and 80 × 1 × 80 grid dimensions showed 1.2%, 1.8% and 2.1% drop in total pressure drawdown respectively. This change is small and insignificant. For the case of a shale thickness of 0.1, the gas production as seen in **Fig. 2** increases with increase in grid cells. When the number of grid cells in z-direction was increased from 10 to 100, the gas production increased by 0.5% i.e. from 6534.1 Bscf to 6564.9 Bscf. There was no point in using finer grid because they take longer to simulate without a significant improvement on the result.

Permeability Sensitization

Permeability contrast in reservoirs affects the predicted value of GIIP, the reservoir pressure response, gas production and the ultimate recovery. For the homogeneous reservoir model presented in Table 2, the predicted value of GIIP from extrapolation of G_p vs $1/B_g$ due pressure drawdown from the numerical simulation results gave 11.3 Tscf as expected (Fig. 3). This matched the GIIP from analytical calculation which also gave 11.3 Tscf. As the lower region permeability was reduced from 100 mD to 0.000001 mD, an upward trend of the plot was observed. This suggests that high permeability contrast would lead to a higher and optimistic prediction of GIIP. Table 4 shows the several cases analysed. (Note: The key represents the different permeability of the lower region).

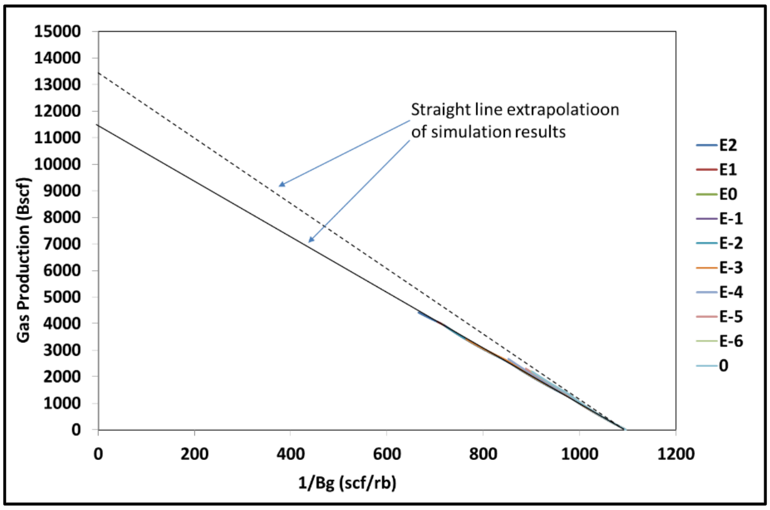


Fig. 3–Gas production vs $1/B_g$ for different permeability cases (key shows different permeability in mD)

Reservoir engineers have to be careful in the prediction of GIIP from pressure data especially at beginning of the field life as the source of uncertainty there is the greatest (Worthington, 2009). In Fig. 3, the homogeneous model's prediction is correct at the extrapolated value of 11.3 Tscf but as the permeability contrast increases, the deviation becomes highly pronounced reaching a value of 13.3 Tscf at 0.000001 mD. High permeability contrast will show a deviation above the normal plot, simulating higher GIIP. The reservoir pressure response throughout the entire field life for the different cases is shown in **Figs. 4 and 5.**

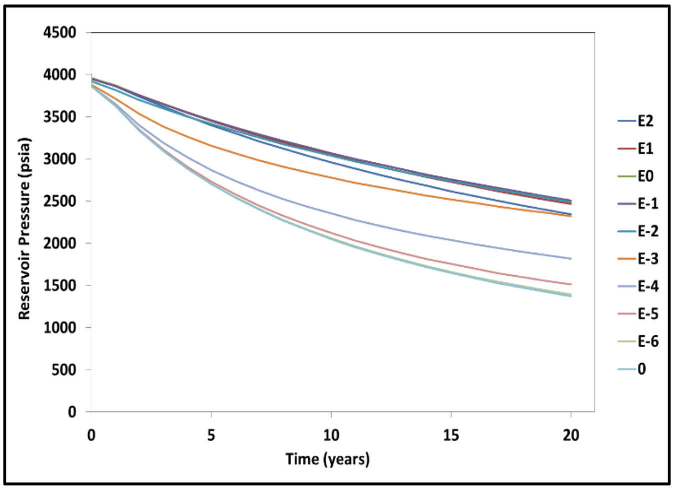


Fig. 4–Reservoir pressure response (top region) for the entire field life (the key shows different permeability of the lower region (key shows different permeability in mD)

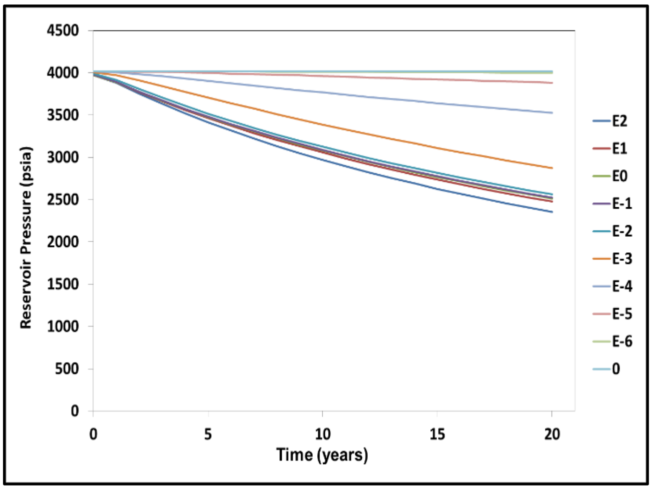


Fig. 5–Reservoir pressure response (bottom region) for the entire field life

Normally during production, the pressure of the reservoir decreases with time. This pressure drawdown (the initial reservoir pressure – final reservoir pressure) is a function of the permeability of the different layers that make up the reservoir. In all cases, as shown in Fig. 4, the reservoir pressure decreases with time (as expected). This decreasing trend is seen to be steeper as the permeability of the lower region decreases. The total pressure drop thus increases from 1657 psia (at 100 mD) to 2630 psia (0 mD). This is expected owing to the fact that as the permeability of the lower region decreases, the depletion or gas production occurs over a much smaller region thus making the total pressure drawdown increase. In other words, as the reservoir sees less of the lower region, the volume to deplete becomes smaller thus producing a higher pressure drop in the top region. The bottom region of the reservoir shows a decline in reservoir pressure over time as seen in Fig. 5. The region's pressure drawdown decreases from 1663 psia (at 100 mD) to 0 psia (at 0 mD). This occurs at its lowest possible recovery. From **Fig. 6,** the total pressure drawdown decreases to a minimum at 0.000001 mD (19 psia). This pressure drawdown is so small that for the entire 20 years of production, it is assumed that at such permeability the contribution to production from the lower region based on the pressure drawdown is almost insignificant. The total pressure drawdown of the reservoir having different lower permeability between 100 mD and 0.01 mD falls in a similar range of 1500 psia to 2000 psia as shown in Fig. 6. This pressure drawdown declines below 0.01 mD making the permeability a significant turning point or a cutoff for meaningful recovery for the entire reservoir. Thus for a high permeability reservoir with adjacent layer of low porosity zones, the total pressure drawdown will be significantly constant within a certain range over the lifetime of the field so long as the low permeability zone cutoff of 0.01 mD is not reached for a shale thickness of 0.3.

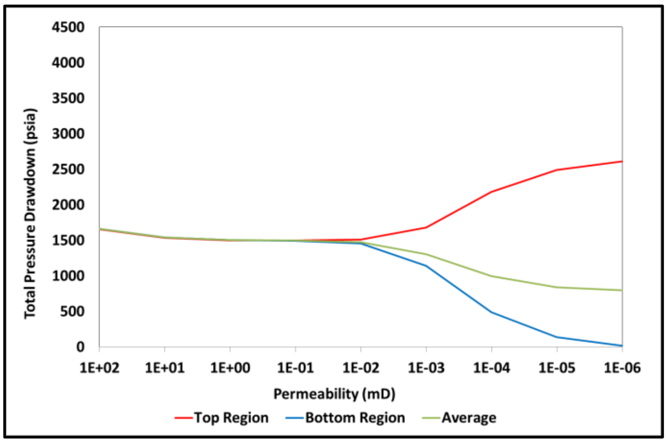


Fig. 6–Total pressure drawdown in the reservoir with

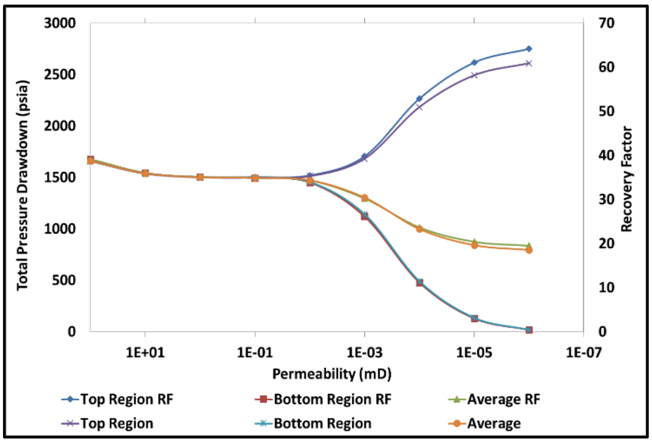


Fig. 7–Comparison of total pressure drawdown and the

changing permeability of the lower region **recovery factor with respect to permeability**

The recovery factor and the pressure drawdown plots are similar and show characteristically similar trends as seen in **Fig. 7.** Increased pressure drawdown leads to increased gas production. **Fig. 9** shows that the recovery factor of all regions in the reservoir lies between 35% and 40% for lower region permeability above 0.01 mD. Below 0.01 mD, the recovery factor of top begins to increase reaching its maximum value of 64% at 0.000001 mD while the lower region decreases reaching a minimum of 0.4% at 0.000001 mD. The contrast in the permeability has no effect on the recovery until a cutoff value of 0.01 mD is reached, thence the ultimate recovery (recovery of the entire region) begins to decrease.

"Net pay is a key parameter in reservoir evaluation because it identifies those penetrated geological sections that have sufficient reservoir quality and interstitial hydrocarbon volume to function as significant producing intervals" (Worthington, 2009) and from the result shown in Fig. 9, reservoirs with permeability lower than 0.01 mD should not be regarded as net pay. This does not support the statement of Worthington (2005) "The longstanding industry default (net-reservoir) cutoffs of 0.1 mD for gas reservoirs".

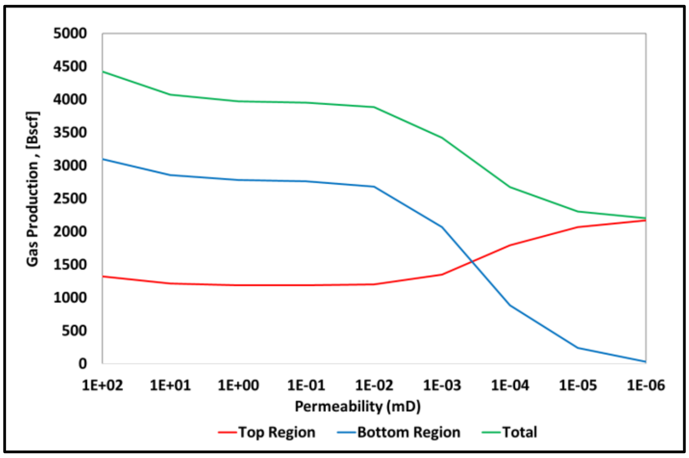


Fig. 8–Gas production vs permeability

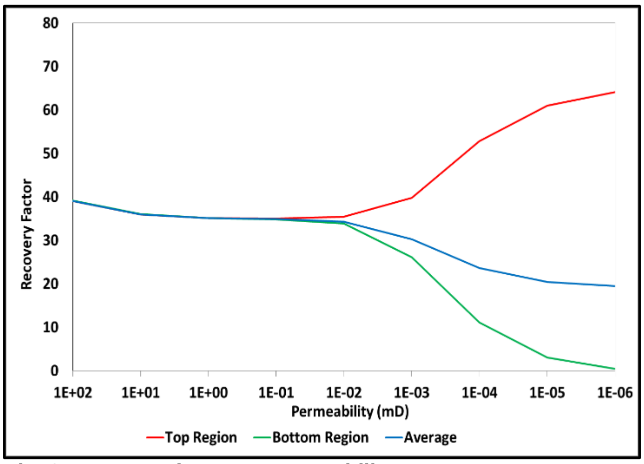


Fig. 9–Recovery factor vs permeability

It is important to note that gas reservoirs with lower region permeability lower than 0.01 mD can still produce gas but this will occur at very low recovery rate. For example, permeability as low as 0.0001 mD, 000001 mD or 0.000001 mD will yield recovery of 11.3%, 4% and 0.4% respectively.

Transmissibility Sensitization

The effect of having a transmissibility factor between two high permeability zones was studied. The top and bottom regions were kept at 100 mD and a transmissibility multiplier was set between the regions as shown in Table 5. **Fig. 10** shows the reservoir pressure throughout the field life for the top and bottom regions. For the top region, decrease in the reservoir pressure with time is expected. As the transmissibility reduces, the total pressure drawdown increases. This is similar to the permeability effect earlier discussed in Fig. 4. The transmissibility effect acts as a barrier to production causing a large pressure drawdown at the top region. **Fig. 11** shows the reservoir over field life time in the bottom region in response to the decreasing transmissibility. Again, the total pressure drawdown decreases with decreasing transmissibility. This effect is similar to the effect of decreasing permeability in the lower region earlier discussed in Fig. 5. The effect of decreasing the transmissibility is similar to the effect of decreasing permeability.

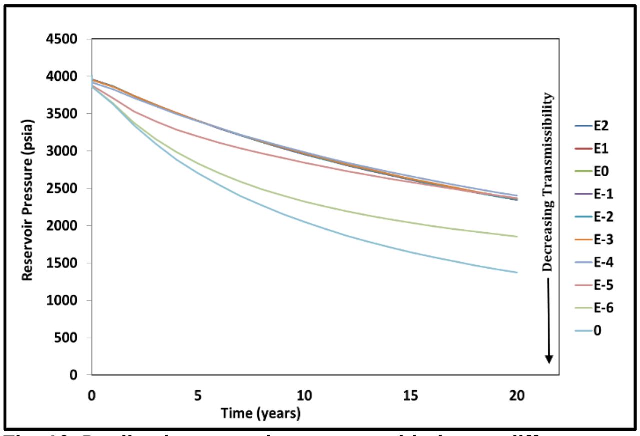


Fig. 10–Decline in reservoir pressure with time at different different transmissibility (top region) (key shows different

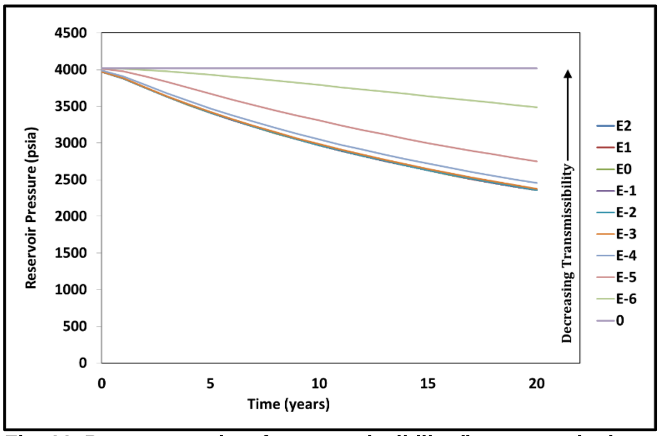


Fig. 11–Pressure vs time for transmissibility (bottom region)

transmissibility)

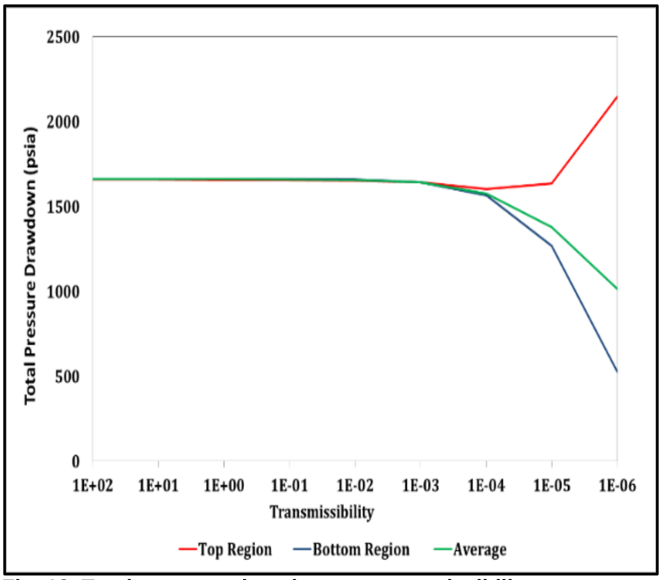


Fig. 12–Total pressure drawdown vs transmissibility

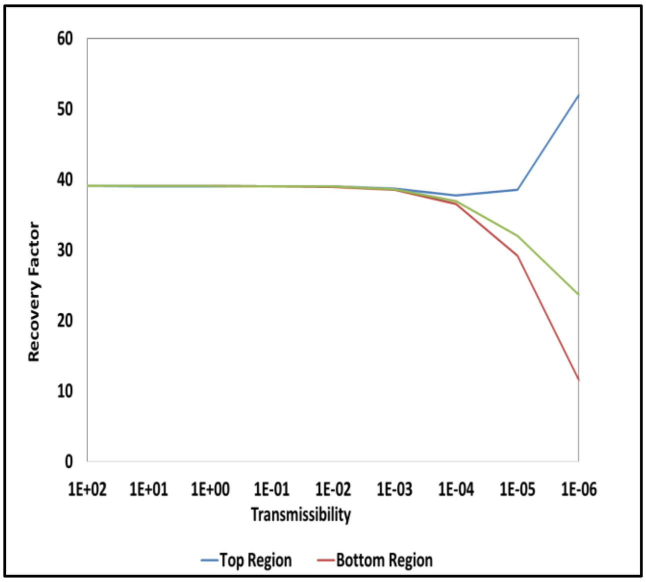


Fig. 13–Recovery factor vs transmissibility

Fig. 12 shows that the total pressure drawdown in a reservoir will be fairly constant until a transmissibility factor of 0.001 is reached. **Fig. 13** shows that the recovery factor declines at transmissibility barriers lower than 0.001. In comparing the transmissibility and permeability contrast effect, **Fig. 14** shows that the behavior is not similar i.e. a transmissibility barrier behaves differently from a reservoir with permeability contrast. For the top region as shown in Fig. 14, the pressure drawdown begins to increase at a low transmissibility factor 0.00001 but increases at a lower region permeability of 0.01 mD. The gas production from the top and bottom regions remains constant but changes after a transmissibility value of 0.001 as seen in Fig. 14. However, the total gas production will not decline until a transmissibility factor of 0.00001 is reached. This means that even after a drop in gas production in the top region, gas production at the bottom region will compensate for this effect thus stretching the constant total gas production to 0.00001 after which production declines. This is because of better communication in the lower reservoir from its base to the transmissibility barrier.

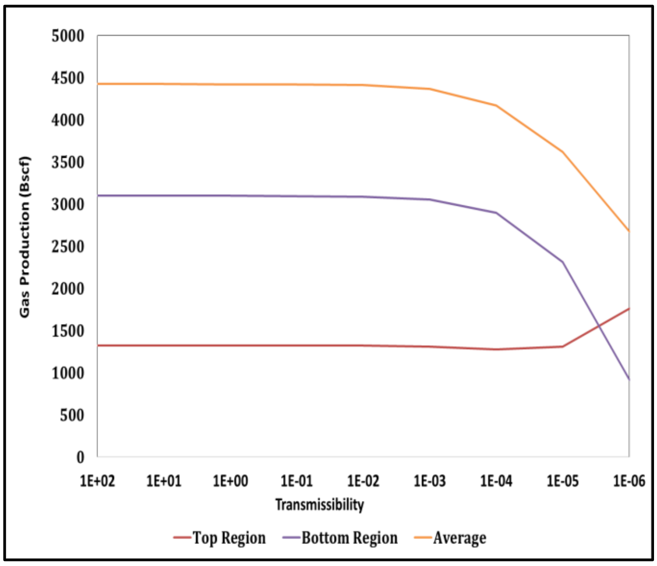


Fig. 14–Gas production vs transmissibility

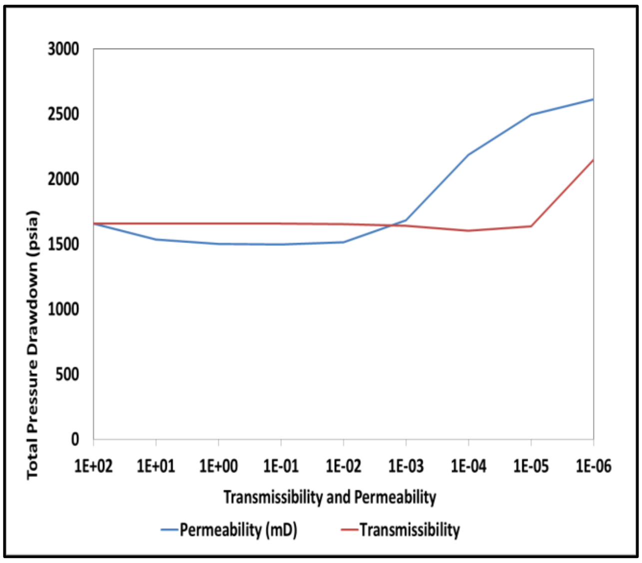


Fig. 15–Comparison of the total pressure drawdown for different permeability and transmissibility cases

Shale Thickness Sensitization

This model varied the thickness of the bottom region of the reservoir to study its effect on reservoir pressure response, gas production and ultimate recovery. The grid size of 10 × 1 × 10 and a permeability of 0.0001 mD at the bottom region was used. The thickness of the reservoir was set at 100m. 0.1 fraction of this total thickness i.e. 10m was assigned permeability of 0.0001 mD, then same was done for 20m and 30m up to 90m representing 0.2, 0.3 up to 0.9 fraction of the entire reservoir thickness respectively as seen in Table 6. The aim was to study the effect of changing shale thickness on the reservoir pressure response, pressure drawdown, gas production and recovery.

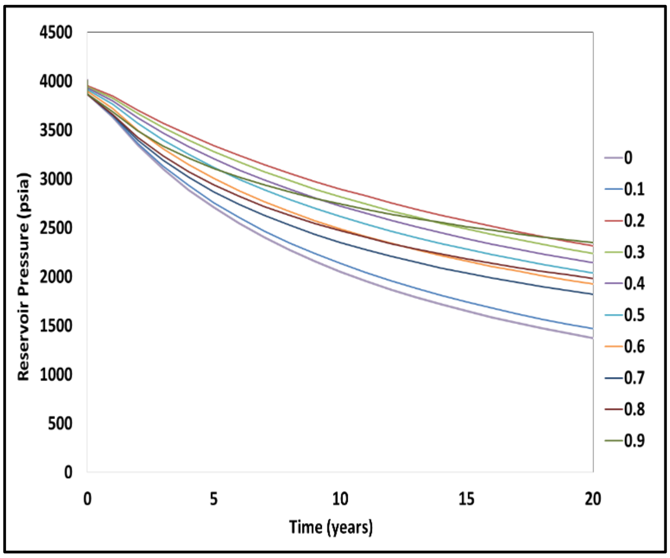


Fig. 16–Pressure vs time (top region) for different shale thickness (at 0.0001 mD) (the key shows different shale fraction)

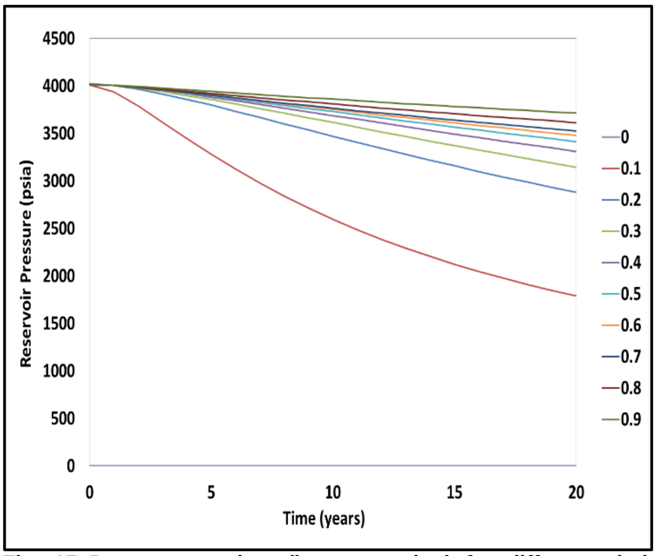


Fig. 17–Pressure vs time (bottom region) for different shale thickness (at 0.0001 mD)

Fig. 16 shows that the reservoir pressure decreases with time in the top region (as expected). Here, the pressure drawdown decreases, then increases and finally decreases. This behavior can be attributed to the fact that the pressure response of the changing thickness of the top (high permeability region) is highly influenced not only by the permeability of the region below but also its thickness.

Increasing the thickness of the shaly region produces a sharp increase in pressure drawdown which declines as the shale thickness increases. The sharp increase in pressure drawdown occurs at a shale thickness fraction of 0.02 or 2% of the entire reservoir thickness **(Fig. 20).** This does not mean that the maximum gas production occurs at 0.02 shale fraction (maximum gas production occurs at 0.3 shale fraction) but that recovery is maximum at that point as shown in **Figs. 19 and 20.**

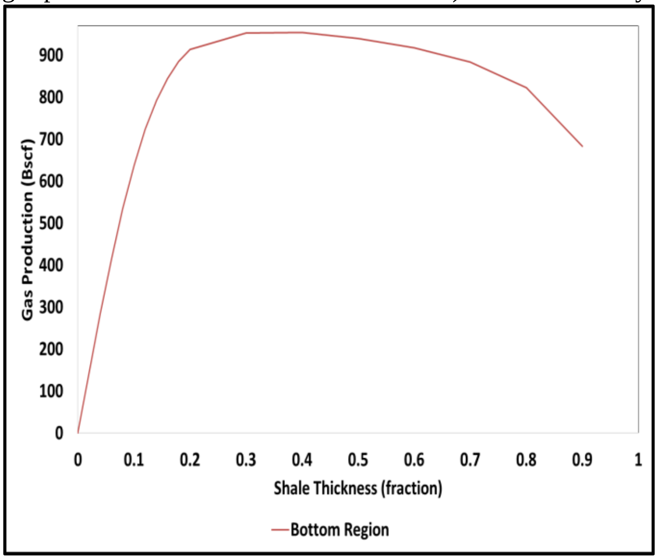


Fig. 18–Gas production vs shale thickness (bottom region)

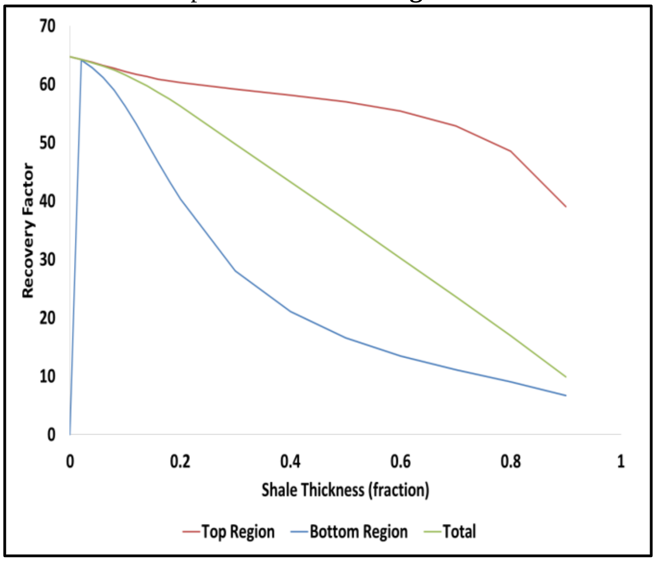


Fig. 19–Gas production vs shale thickness (all regions)

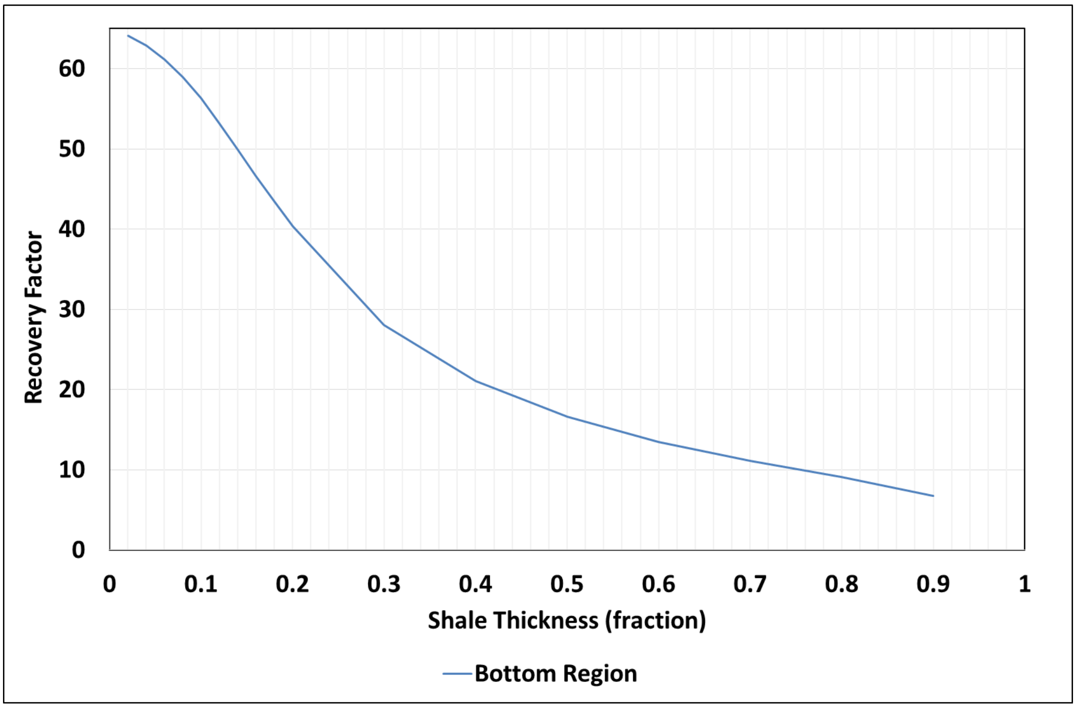


Fig. 20–Gas production vs shale thickness (bottom region)

The case highlighted earlier was specifically for the bottom region permeability of 0.0001 mD. **Figs. 22 and 24** show similar plots for different permeability cases of the bottom region: 0.001 mD, 0.0001 mD, 0.00001 mD and 0.000001 mD. **Fig. 24** shows the effect of an additionally changing permeability on recovery vs shale thickness of the bottom region. Fig. 22 shows the gas production from the bottom layer. It shows that maximum gas production occurs at shale fraction of 0.3 for all the permeability cases i.e. 0.001 mD, 0.0001 mD, 0.00001 mD and 0.000001 mD cases although at lower permeability of 0.00001 mD and 0.000001 mD the 3D plot seems to flatten out meaning that gas production at that permeability is quite low. Fig. 21 shows that production from the top layer decreases as shale thickness increases. Fig. 24 shows the recovery factor of the bottom region. As shown earlier (Fig. 20), for the lower region permeability case of 0.0001 mD, recovery factor was maximum at 0.02 shale fraction. Fig. 24 shows the recovery factor for a range of lower region permeability cases. It can be seen from Fig. 24 that recovery factor is maximum at 0.02 for all permeability cases of 0.001 mD, 0.0001 mD, 0.00001 mD and 0.000001 mD. This suggests that at any lower region permeability, the bottom region of the reservoir will experience its maximum recovery at 0.02 shale fraction. Fig. 24 further shows that after 0.3 shale fraction, the recovery factor (in all permeability cases) begins to decline and will decline sharply at much lower permeability of 0.00001 mD and 0.000001 mD. Hence, maximum recovery occurs in the lower region at shale fraction of 0.02, maximum gas production occurs at 0.3 shale fraction and that recovery factor declines rapidly after 0.3 shale fraction in the bottom region

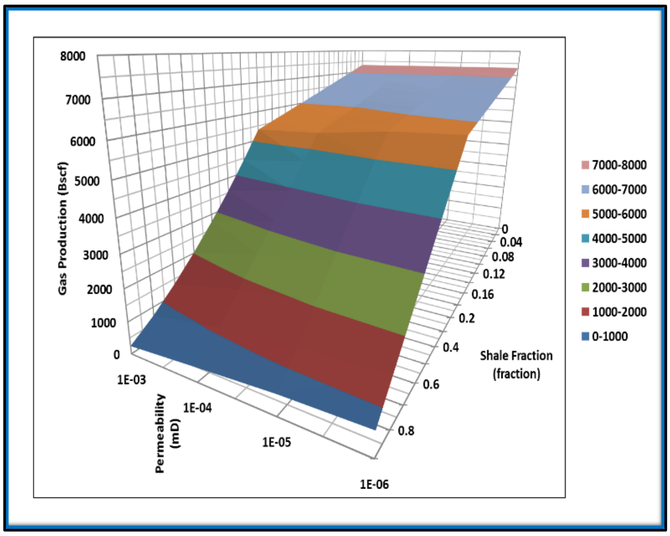


Fig. 21–Gas production vs shale thickness (top region) thickness for different permeability cases

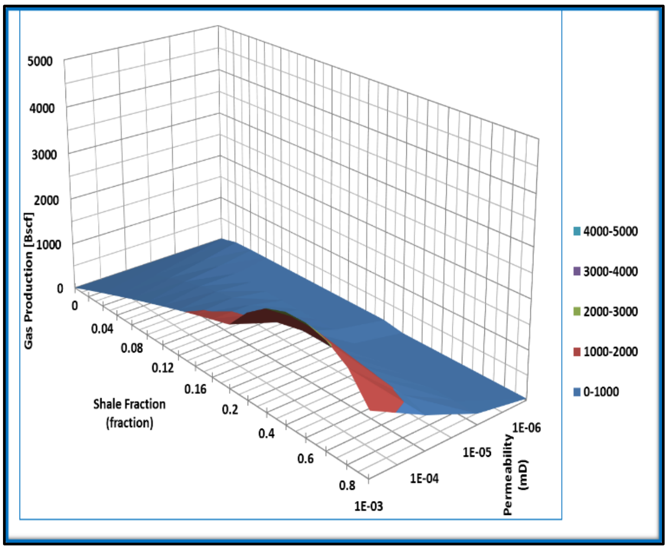


Fig. 22–Gas production vs shale thickness (bottom region) for different permeability cases

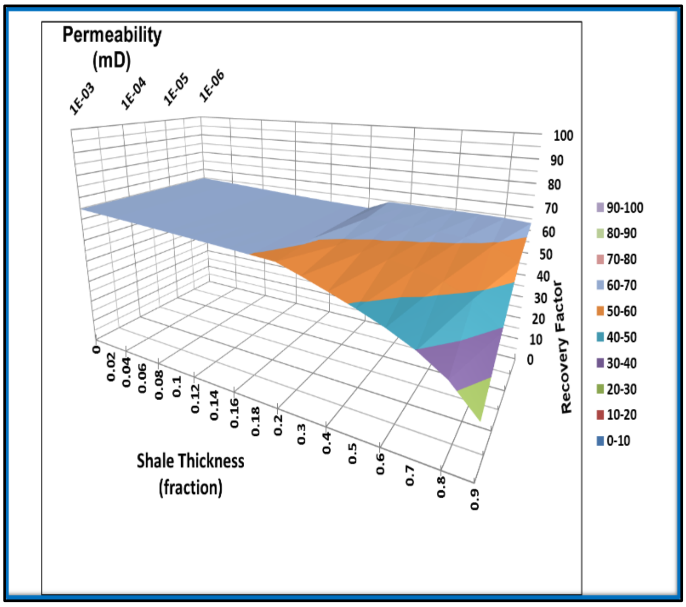


Fig. 23–Recovery factor vs shale thickness for the different permeability cases (top region)

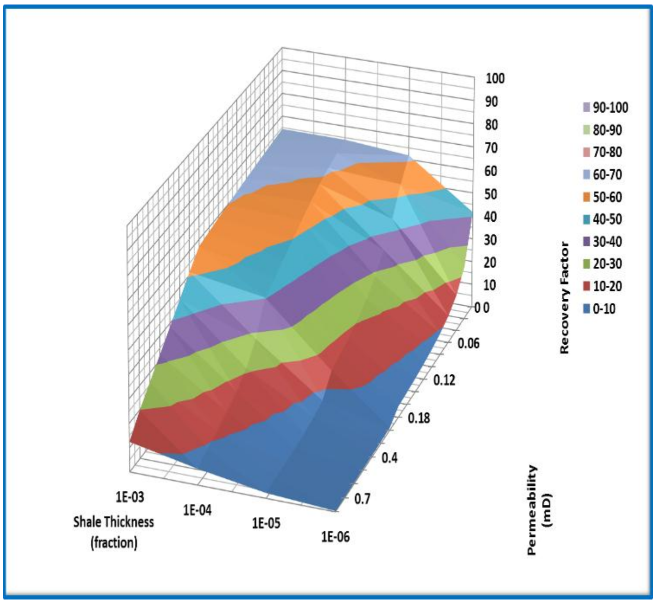
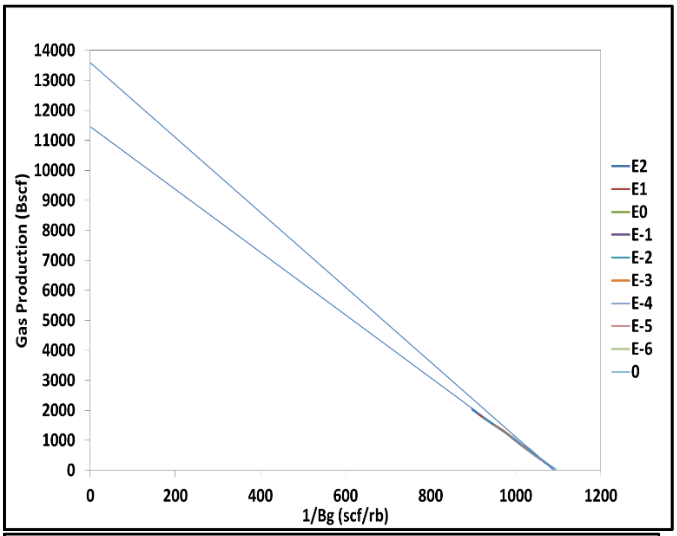


Fig. 24–Recovery factor vs shale thickness for different permeability cases (bottom region)

Constant Rate Sensitization

Earlier simulations were done at constant bottomhole pressure. The predicted GIIP at constant bottomhole pressure was seen to give 11.3 Tscf (for the homogeneous model). This section investigates the effect of producing gas from a reservoir at constant rate and not constant bottomhole pressure and compares both. The **Figs. 25 and 26** show the effect of producing gas at constant bottomhole pressure (100 psia). This gives a predicted GIIP of 11.3 Tscf. **Figs. 27 and 28** show the effect of producing gas at constant rate. Here, the predicted GIIP for the homogeneous case is still 11.3 Tscf. Thus changing the rate does not affect the predicted value of GIIP. Figs. 25 and 27 compares the effect of changing the lower regions permeability during constant bottomhole gas production and constant rate production. The predicted GIIP at 0.000001 mD is 13.5 Tscf for the constant BHP case and 13 Tscf for the constant rate case. This shows a deviation of ~4%. Constant rate gas production does not change the predicted value of GIIP for homogeneous case. In fact it matches it (same value for constant bottomhole pressure from numerical simulation and material balance calculation). Fig. 27 shows that at very low permeability (0.000001 mD) in the bottom region, the predicted value at constant rate differs by more than 13% while that of constant bottomhole pressure differs by more than 19%. Thus, we are more likely to get a better prediction of GIIP from a constant rate production than a constant bottom hole pressure condition at very low permeability.



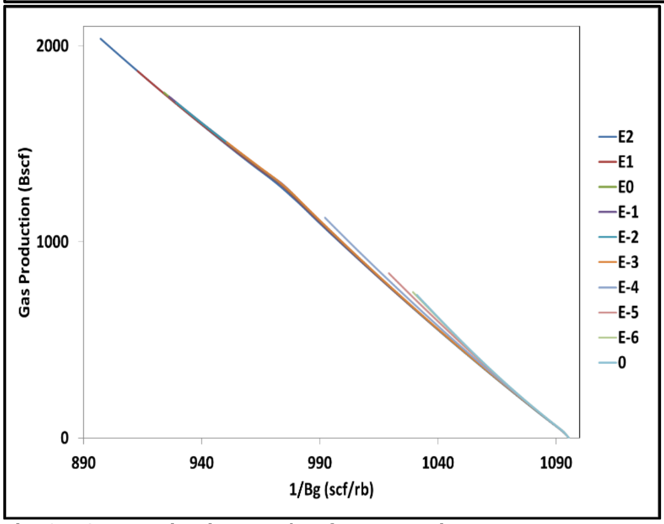
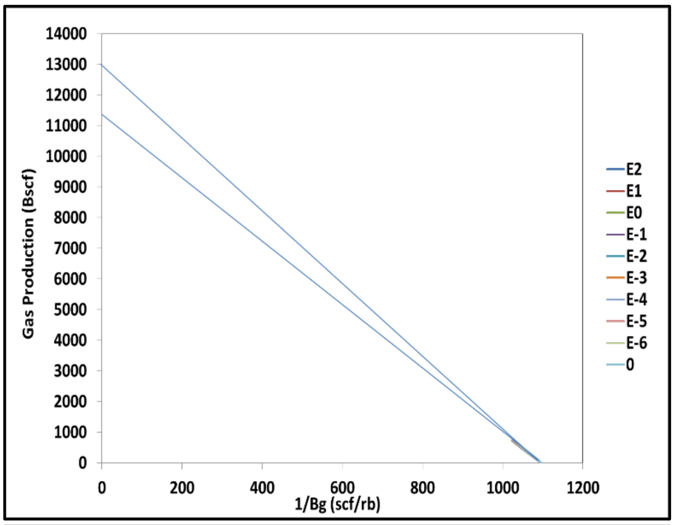


Fig. 25–Gas production vs 1/Bg for reservoir at constant BHP (key shows different permeability in mD)

Fig. 26–Gas production vs 1/Bg for reservoir at constant BHP (zoomed)



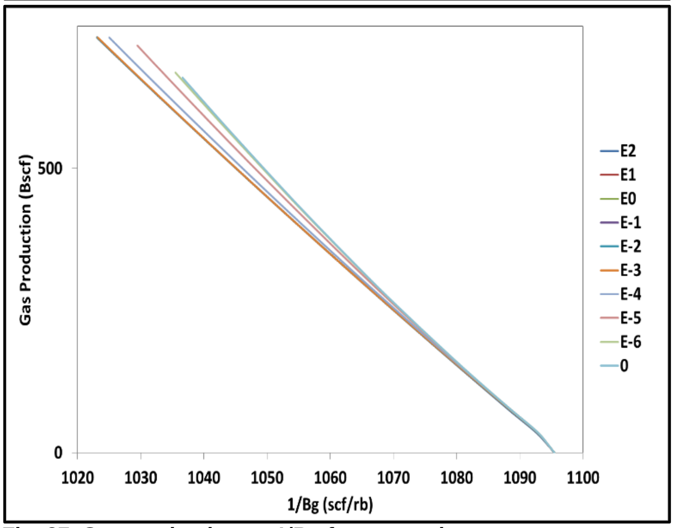


Fig. 27–Gas production vs 1/Bg for reservoir at constant rate

Fig. 28–Gas production vs 1/Bg for reservoir at constant rate (zoomed)

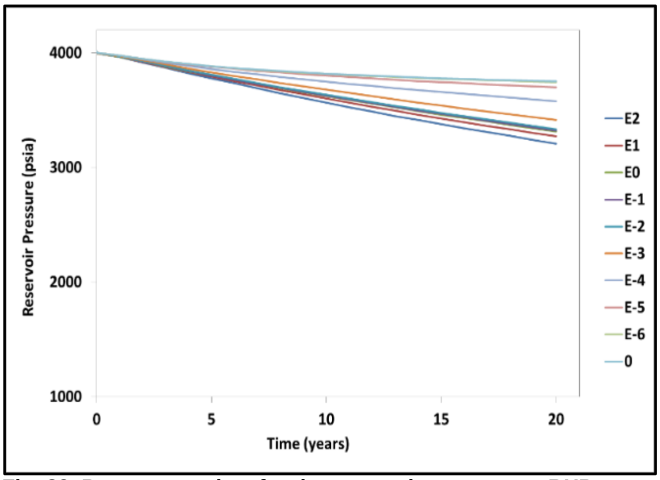


Fig. 29–Pressure vs time for the reservoir at constant BHP

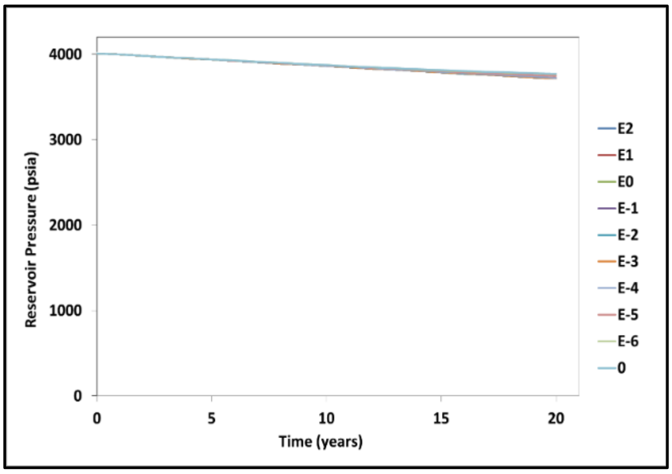


Fig. 30–Pressure vs time for the reservoir at constant rate

The reservoir pressure response shown in the **Figs. 31 and 32** show a slow decline over the field lifetime (as expected). This is as a result of the constant production rate being so small compared to gas production on BHP control. Most normal production in the gas industry occur at constant rate. The issue of constant rate vs constant BHP gas production is driven both by government policies, company's policies and economics. If return on investment and timeliness of such is of the essence then production at constant rate may not achieve the aim whereas most government would want a reasonable fieldlife to ensure maximum exploitation of the natural resource of the land. This is one of the ways of ensuring optimum reservoir management.

Surface facilities are also better handled when the rate is predictable to avoid damage due to undulating production rates. Although recovery at constant rate is smaller compared to recovery at constant bottomhole pressure over a considerate time interval as seen in **Fig. 31,** the tradeoff between both cases is always up for debate. Fig. 31 shows that recovery factor is seen to gradually decline on BHP control with decreasing lower region permeability. Since rate is set at 100 MMscf/d, the recovery factor at constant rate is approximately constant at all permeability cases of the lower region and throughout the field life as shown in Fig. 31.

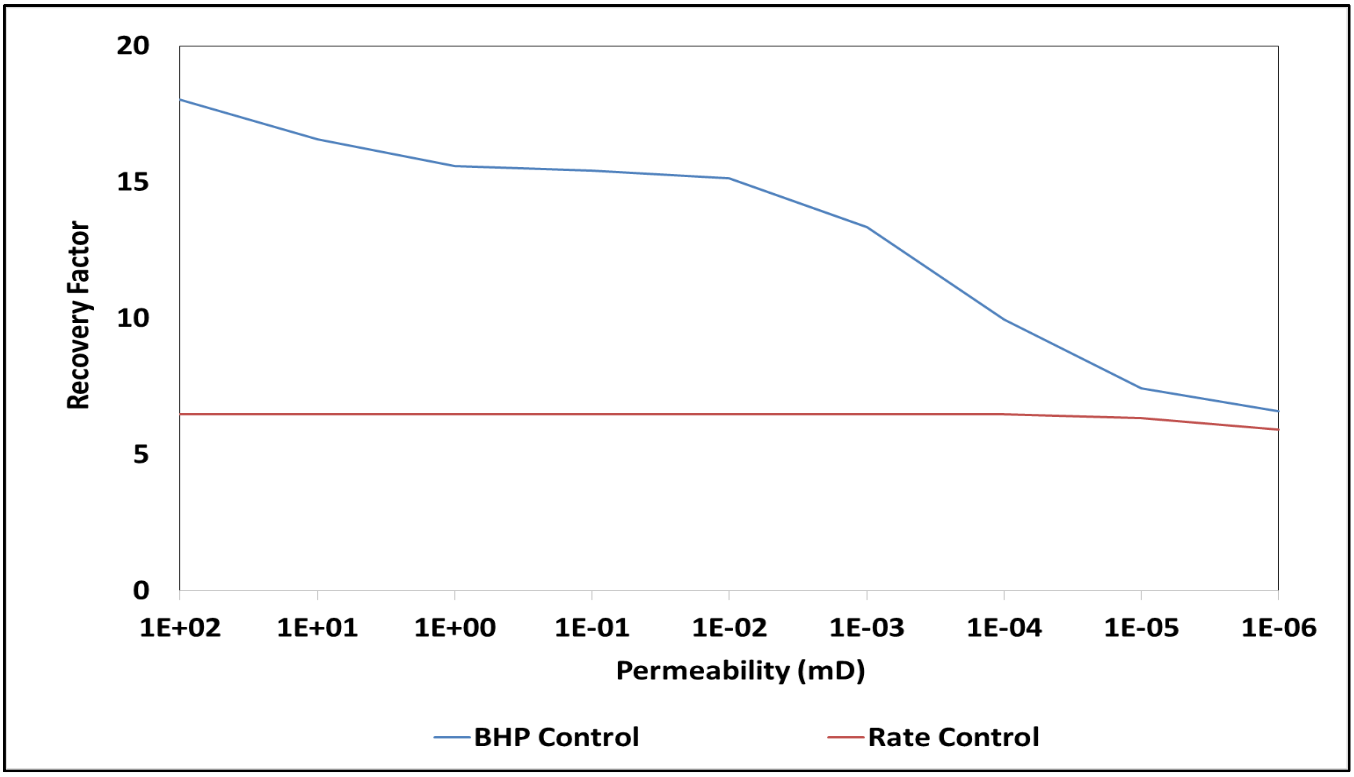


Fig. 31– Recovery factor vs permeability

Discussion

This study shows the effect grid refinement, permeability contrast, transmissibility, varying shale thickness, and production rate have on reservoir pressure response, gas production and recovery. The effect of doubling the grid dimension was seen to produce a little drop in pressure drawdown. Increasing the gridsize to 20 × 1 × 20, 40 × 1 × 40 and 80 × 1 × 80 showed 1.2%, 1.8% and 2.1% drop in total pressure drawdown respectively. This change is quite small and will not affect the result significantly. According to Worthington (2009), 0.1 mD is the cutoff for net pay inclusion of a low permeability reservoir. This does not match the results of this simulation as can be seen in Fig. 9. The result shows that reservoir with permeability as low as 0.01mD can still add to net pay and that below it recovery factor tends to decrease significantly. If a transmissibility barriers traverses a high permeability region, the effect will not be the same as a high permeability region adjacent to a low permeability region. Increasing the shale thickness fraction of a reservoir increases and then decreases the recovery factor in the lower region. The recovery factor in the lower region increases to a maximum at 0.02 shale fraction of the entire reservoir thickness. The bottom region also experiences maximum gas production at 0.3 shale fraction. If a high permeability reservoir is adjacent to a low permeability reservoir, expansion of the gas into the higher permeability region increases the apparent recovery of the gas. Constant rate production or constant bottomhole production has no effect on predicted value of GIIP. If heterogeneities are present, the constant rate production will give a closer prediction of the GIIP than the constant BHP production. Constant rate production ensures quasi-constant recovery but depleting such reservoir might take place over a much longer period than if it was done at constant bottomhole condition.

Conclusion and Recommendation for Further Work

This study shows that a gas bearing formations with low permeability adjacent to high permeability layers can add to the net pay and that the thickness of the low permeability layer plays an important role in the recovery process. From the analysis, the following conclusions were drawn:

1. The grid refinement made little or no significant impact to the overall result.
2. 0.01 mD can be said to be a cutoff for net pay inclusion of low permeability reservoirs
3. Pressure response of the changing thickness of the top (high permeability region) is highly influenced not only by the

permeability of the region below but also its thickness.

4. If a transmissibility barriers traverses a high permeability region, the effect will not be the same as a high permeability region adjacent to a low permeability region.
5. Maximum recovery occurs in the lower region at shale fraction of 0.02, maximum gas production occurs at 0.3 shale fraction and recovery factor declines rapidly after 0.3 shale fraction in the bottom region
6. The production rate of a homogeneous reservoir has no influence on the predicted value of GIIP obtained from pressure data but on the recovery factor
7. For a heterogeneous reservoir, constant rate production data gives a better prediction of GIIP than constant BHP production.

More work can still be done in this area of study such as increasing the upper boundary of permeability or permeability contrast and studying its effect on the thin bedded zones.

Nomenclature

B_g	=	Gas Formation Factor (rcf/scf)
B_{gi}	=	Initial Gas Formation Factor (rcf/scf)
BHP	=	Bottom Hole Pressure (psia)
GIIP	=	Gas Initially in Place (ft^3)
G_p	=	Gas Produced (ft^3)
H	=	Thickness of Reservoir (m)
NTG	=	Net to Gross
P	=	Pressure of the Reservoir (psia)
P_f	=	Final Pressure of the Reservoir (psia)
P_i	=	Initial Pressure of the Reservoir (psia)
PVT	=	Pressure, Volume, Temperature
S_{wc}	=	Connate Water Saturation

Subscripts

c	=	connate
f	=	final
g	=	gas
i	=	initial
p	=	produced
w	=	water

References

Baillie K., and James-Romano J. Identifying and Quantifying Thin-Bedded Pay (Part B): The Use of Dynamic Data to Evaluate Productivity Potential in Gas Reservoirs. SPE 133535 presented at the 2010 Trinidad and Tobago Energy Resources Conference, Port of Spain, Trinidad, 27-30 June.

ECLIPSE Technical Description, 2010.1 Release, Schlumberger (2010)

ECLIPSE Reference Manual, 2010.1 Release, Schlumberger (2010)

Garcia C. A., and Villa J. R., Pressure and PVT Uncertainty in Material Balance Calculation. SPE 107907 presented at the 2007 SPE Latin American and Caribbean Petroleum Engineering Conference held in Buenos Aires, Argentina, 15-18 April 2007.

Ikoku, Chi U. (1984). Natural Gas Reservoir Engineering. Canada: John Wiley & Sons, Inc.. 503.

Ramagost B. P. and Farshad F. F., P/Z Abnormally Pressured Gas Reservoirs. SPE 10125 presented at the 56th Annual Fall Technical Conference and Exhibition of Society of Petroleum Engineers of AIME, held in San Antonio, Texas, October 5-7 1981.

Russell D. G., and Prats M., Performance of Layered Reservoirs with Crossflow Single-Compressible-Fluid Case. SPE 99 presented at the 36th Annual Fall meeting of SPE held in Dallas, 8-11 Oct. 1961.

Sylvester I. F., Cook R., Swift R., Pritchard T., and McKeever J., Integrated Reservoir Modelling Enhances the Understanding of Reservoir Performance of the Dolphin Gas Field, Trinidad and Tobago. SPE 94343 presented at the 2005 SPE Europec/EAGE Annual Conference held in Madrid, Spain, 13-16 June 2005.

Worthington P. F., Net Pay: What is it? What does it do? How do we quantify it? How do we use it? SPE 123561 presented at the 2009 SPE Asia Pacific Oil and Gas Conference and Exhibition held in Jakarta, Indonesia, 4-6 August 2009.

Worthington P. F., The Application of Cutoffs in Integrated Reservoir Studies. SPE 95428 presented at the 2005 SPE Annual Technical Conference and Exhibition held in Dallas, Texas, U.S.A., 9-12 October 2005.

Appendix A – Critical Literature Review

MILESTONES IN RECOVERY FROM THIN NET PAY IN GAS FIELDS

SPE Paper No	Year	Title	Authors	Contribution
99	1961	"Performance of Layered Reservoirs with Cross flow-Single Compressible Fluid Case"	D. G. Russell, M. Prats	First to analytically show the performance of well in a bounded layered reservoir with cross flow
81077	2003	"Quantification of Hydrocarbon Reserves in thinly laminated shaly-sandstone formations"	Tim Pritchard, Nick Colley, Jonathan Bedford	Reviews and proposes best interpretation methods of quantifying hydrocarbon reserves in thinly laminated shaly-sandstone formations with the associated errors.
94343	2005	"Successfully Cycling a Low-Permeability, High-Yield Gas Condensate Reservoir "	I.F Sylvester, R. Cook, R. Swift, T. Pritchard and J. McKeever	Describes the impact of a comprehensive reservoir modelling on reservoir performance.
95428	2005	The Application of Cutoffs in Integrated Reservoir Studies	Worthington P. F.,	Describes the different cuttoffs in reservoir studies
107907	2007	Pressure and PVT Uncertainty in Material Balance Calculation	Garcia C. A., and Villa J. R.,	Reviews the uncertainties in PVT and Material Balance Calculation
123561	2009	Net Pay: What is it? What does it do? How do we quantify it? How do we use it?	Worthington P. F.,	Describes the concept of Net Pay
133535	2010	"Identifying and Quantifying Thin Bedded-Pay. The Use Of Dynamic Data To Evaluate Productivity Potential In Gas Reservoirs"	K. Baillie, J. James-Romano	Describes the use of dynamic data to identify characteristics of thin bed pay.

Appendix B – Eclipse data file for 2D Homogeneous Model of Simple Gas Field with no Aquifer Influx

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Gas Field With no Aquifer Influx
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GAS
WATER

UNIFIN
UNIFOUT

FIELD

TABDIMS
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WELLDIMS
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1 'JAN' 1994 /



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GRID
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RPTGRID
  TRANX ALLNNC /

GRIDFILE
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    1        1        /

INIT
NOECHO



DX
100*3280.84 /
DY
100*32808.4 /
DZ
100*32.8084 /
PORO
100*0.2 /

PERMX
100*100 /
PERMY
100*100 /
PERMZ
100*100 /
TOPS
10*3280 /



BOX
1 10 1 1 1 3 /
PERMX
30*100/

PERMY
30*100/
```

```
PERMZ
30*100/
ENDBOX



BOX
1 10 1 1 4 10 /
PERMX
70*100/

PERMY
70*100/

PERMZ
70*100/
ENDBOX



/

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EDIT
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PROPS
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ROCK
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  4000     2.8E-6      /

PVTW
--RefPres  Bw       Cw        Uw     viscosibility
  4000     1.013    2.70E-6   0.4    0.0  /

PVDG
--Pg      Bg           Ug
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  600         6.0076   0.01487
  800         4.4705   0.01519
  1000        3.5532   0.01541
  1500        2.3403   0.01611
  2000        1.7467   0.01707
  2500        1.4010   0.01804
  3000        1.1784   0.01905
  3500        1.0254   0.02020
  4000        0.9148   0.02136
  5000    0.7676       0.02376 /

SWFN
---Sw     Krw      PC(o-w)
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0.25        0.007287329          0
0.3         0.021415824          0
```

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0.4     0.071980964     0
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0.5     0.152290303     0
0.55    0.203599048     0
0.6     0.262343843     0
0.65    0.328524688     0
0.7     0.402141582     0
0.75    0.483194527     0
0.8     0.571683522     0
0.82    0.609161214     0       /


SGFN
---Sg   Krg     PC(o-w)
0.18    0.0     0
0.2     0.04    0
0.25    0.0625  0
0.3     0.09    0
0.35    0.1225  0
0.4     0.16    0
0.45    0.2025  0
0.5     0.25    0
0.55    0.3025  0
0.6     0.36    0
0.65    0.4225  0
0.7     0.49    0
0.75    0.5625  0
0.8     0.64    0
0.82    0.6724  0
1       1       0       /


/

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BOX


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FIPNUM

70*2/


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RPTSOL
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--FOPT
--/
--FOPRH
--/
FWPR
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FPR
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FGPR
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FGPT
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FGPRH
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FGIP
/




FGIPG
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RGIPG
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RGIP
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/


RPR
/

--INTERREGION GAS FLOW
RGFTG
/


-- WELL QUANTITIES
-- WeLL Water Production Rate
WWPR
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WWCT
'PROD1'
/
-- Water Saturation
BSWAT
/
BGSAT
/

/





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/

COMPDAT
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/

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/

DATES

  1 JAN 1995 /
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