EVALUATING THE FACTORS EFFECTING PRESSURE BUILDUP TEST IN FRACTURED RESERVOIRS WITH GAS INJECTION DRIVE MECHANISM

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ABSTRACT

Many factors can influence the shape of a pressure build up curve. An unusual shape may require explanation to have a appropriate analysis, or it may prevent a proper analysis. In addition to wellbore storage effects, hydraulic fractures and natural fractures can have a major effect on build up curve shape and analysis. The shape of the pressure buildup curve also can be affected by fluid and rock interfaces, water-oil contacts, layering, and lateral fluid or rock heterogeneities. Wellbore storage, wellbore damage or improvement, and geometry of the drainage area can also affect the shape of a buildup curve. Additionally, wells with a high gas-oil ratio can show humping during pressure buildup, in such cases, the bottom-hole pressure increases to a peak and after a period of time decreases. In this paper, a well is selected in Haft kel oil field and its build up test have been analysed during 20 years and in three periods from 1990 to 2010. The conditions of well in each period has been analysed and the results show that in addition to wellbore effects, some reservoir effects may influence the build up test in this well.

INTRODUCTION

Frequently, pressure buildup tests are not so simple to be analysed. Many factors can influence the shape of a pressure buildup curve. An unusual shape may require explanation to complete a proper analysis, or it may prevent a proper analysis. In addition to wellbore storage effects, natural and induced fractures, particularly in low-permeability formations, can have a major effect on buildup-curve shape and analysis.

One example of a pressure buildup curve that has an unusual shape when analyzed by the Horner or Miller Dyes-Hutchinson methods is a test run with a non-stabilized rate before testing. It is important to recognize that condition and consider it in the analysis. Other practical problems also can be troublesome. These include a bottom-hole pressure gauge in poor working condition, a leaking pump or lubricator, problems resulting from pump pulling before gauge placement, etc. Additionally, wells with a high gas-oil ratio can exhibit humping during pressure buildup (see Fig. 1), in such cases, the bottom-hole pressure increases to a peak, decreases, and finally increases in a normal manner. In some situations, segregation of water and oil in the wellbore can produce a hump.

The shape of the pressure buildup curve also can be affected by fluid and rock interfaces, water-oil contacts, layering, and lateral fluid or rock heterogeneities. Wellbore storage, wellbore damage or improvement, and geometry of the drainage area can also affect the shape of a buildup curve.

Stegemeier and Matthews showed that gas-liquid (phase) redistribution in the well bore causes anomalous pressure-buildup curves of the form shown in Fig. 1 indicates that phase redistribution is similar to well bore storage, although it is probably more complex than anything else presented in this section. It is important to understand that the behavior illustrated in Fig. 1 is wellbore, not formation, dominated. Pitzer, Rice, and Thomas demon strated this by testing a well once with surface shut-in and a second time with bottom-hole shut-in[1].

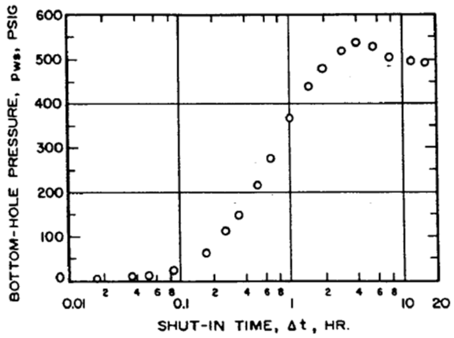

Fig. 1- Pressure build up behaviour showing the effect of fluid segregation in the wellbore. (After Matthews and Russell)

CHANGING WELLBORE STORAGE

Changing wellbore storage happens when the compressibility of the fluid in the wellbore is not constant. It is observed for example when, in a damaged oil well, free gas is liberated in the production string: the reservoir is flowing above bubble point but, after ΔP skin, the fluid becomes two phases.

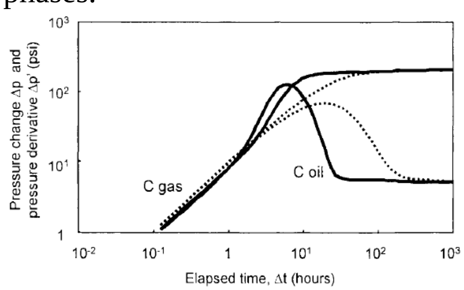

Fig 2. Log-log plot of a build-up example of changing wellbore storage

During build-up periods, the response corresponds to the gas wellbore storage coefficient immediately after shut-in, and changes to the lower oil wellbore storage later. This produces a steep increase of derivative and, in some cases, the derivative follows a slope greater than unity at the end of the gas dominated early time response as illustrated in Figure 2[2].

TWO PHASES LIQUID LEVEL

For wells producing different fluid phases (oil + water, or gas + condensate), a phase redistribution happens in the wellbore during shut-in, producing a characteristic "humping" effect.

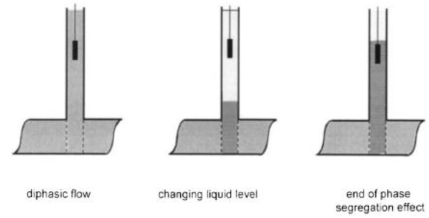

Fig 3. Changing liquid level after phase segregation

In the example Figure 3, the depth of the gauge is above formation. When, after shut-in, the water droplets fall to the bottom of the well, the weight of the fluid column between the pressure gauge and the formation is not constant, but increases as long as the water level rises. Initially the hydrostatic weight corresponds to a low percentage of water, to ultimately reach 100% of water if the interface reaches the gauge depth. In some cases, the build-up pressure can show a temporary decreasing trend after some shut-in time as illustrated Figure 4.

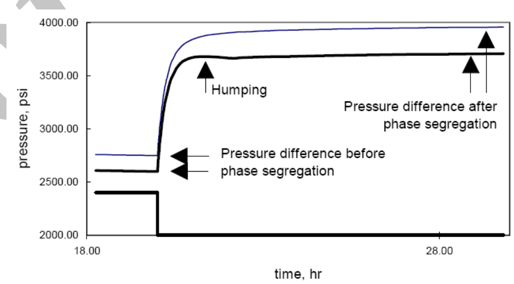

Fig 4. Example of build-up response distorted by phase segregation. Humping effect.

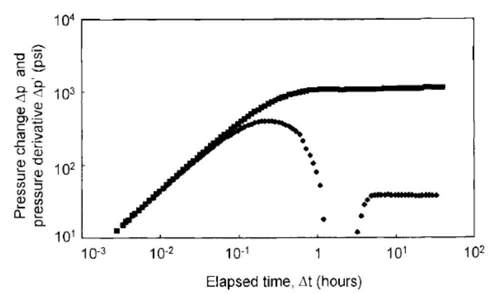

Fig 5. Log-log plot of the build-up example of phase segregation.

When the interface between the two phases stabilizes or reaches the depth of the pressure gauge, the pressure difference between gauge and formation returns to a constant, and the remaining build-up data can be properly analyzed. During the hump when the build-up pressure is declining, the derivative becomes negative (Figure 5)[2].

In some cases, the water cushion created during the first hours of shut-in is slowly reinjected back into the reservoir at later times. Changing liquid level effects can then dominate the entire build-up response, and only drawdown periods are suitable for analysis (Gringarten, 2000). As a general rule, the pressure gauge should always be positioned as close as practically possible to the perforations or producing interval. When phase redistribution is expected in a well producing several phases, the duration of the humping effect is shortened by reducing the distance between the pressure gauge and the reservoir.

INTERFERENCE EFFECTS FROM NEIGHBORING WELLS

When testing wells in producing fields, interference effects from neighboring producers can affect the analyzed pressure data. Ideally, a multiple well simulation model should be used for analysis. Using the proper rate history for each producer, and accurate reservoir geometry, the combined effect of neighboring wells is added to the response of the tested well. This procedure is awkward, and frequently many approximations have to be made. For example, the different wells may not produce from exactly the same layers, or the well spacing and the geometry of the reservoir boundaries are difficult to describe with an analytical model.

As most well responses follow a logarithmic time relationship, the transient effect is clearly reduced as the time increases. When a well test is planned in a multiple well reservoir environment, it is preferable to maintain unchanged the flowing condition of all other wells before the test. If a neighboring well is opened or closed just before or during the well test, its possible interference effect is larger than if no change is made in its flow rate [2].

RESERVOIR - WELL CHARACTRISTICS

Field H is a strongly folded anticlinal structure about 32 km long and varies in width from 2.5 km to 5 km at the original water oil contact (WOC). The original GOC in the main central dome was at 1015 feet sub sea, and the average original WOC of the two flanks was at about 3087 feet sub sea.

Gas injection into this field was started in June 1976 at a rate of 400 million scf/d, when its oil production dropped to about 14000 stb/d with an oil column thickness of about 110 ft. The reservoir pressure was increased from about 1100 psi to about 1410 psi, at the crest. Both wateroil and gas-oil contacts were smoothly moved down shortly after the start of gas injection. The oil column thickness was gradually increased to about 350 ft with water-oil contact at about 2650 ft sub sea and has become nearly stationary after about nine years [4].

Well H-10

This well was drilled in 1927 and start to produce oil with flow rate about 300 bbl/d for 7 years. The production increased gradually till it reached a peak to 6000 bbl/d and as a results of high water cut, the production from this well sttopped and it completed as a water observation well. The production history of this well is illustrated in Fig-6.

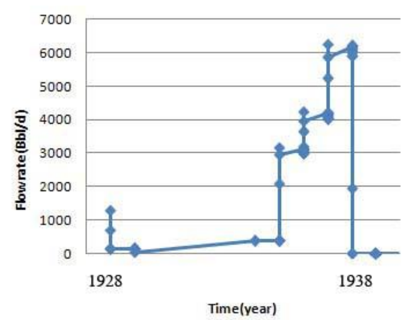

Fig-6. Early production history of Well H-10

In 1990 the intervals 1174-1187 m are perforated and 4000 gal HCL injected in the reservoir. Afterwards, the well has been produced till know, but the sophisticated shape of build up test leads to have a full study over the well conditions during the years after it changes from an observation well to a producing well. The recent production history of this well during 1990 to 2010 is shown in Fig-7. This well starts producing with average flow rate of 900 Bbl/d and its production decreased in year 2000 and remained constant to 500 Bbl/d until now.

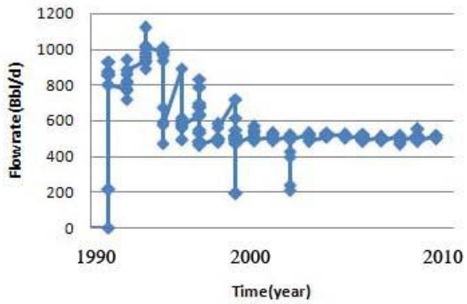

Fig.7- Recent production history of Well H-10

There are two wells near this well that maybe the drainage radius of them has effect on each other. The position of this well and its nearby wells is shown in Fig.8.

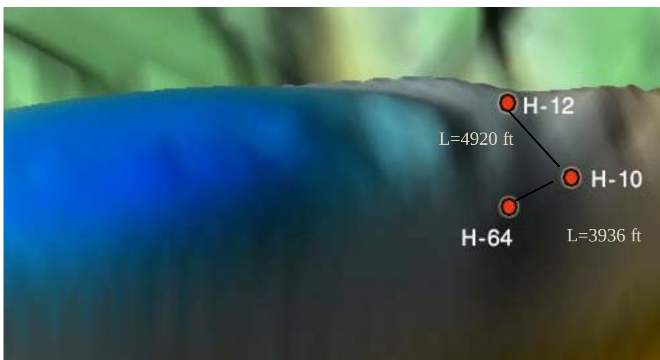

Fig.8- Position of well H-10 and its neighbour wells

The well H-64 is a new well and just in the last test should be included in this diagram for analysis of the well test results.

Case Study 1

The Well test analysis after work over is shown in Fig-9. The results show that skin value as a result of acidizing proir to testing is negative. Naturally fractured reservoirs have two distinct porosities, one in the matrix and one in the fractures. Although naturally fractured reservoirs consist of irregular fractures, they can be represented by equivalent homogeneous dual porosity systems (Warren and Root 1963). The reservoir model in this well is dual porosity with the storativity ratio (ω) of 0.04 (which is defined as the fraction of the total pore volume associated with one of the porosities) and Interporosity Flow Coefficient (λ) of 1.5 × 10^{-6} (which is defined as the ratio of the permeability of the matrix (k_m) to that of the fractures (k_f)).

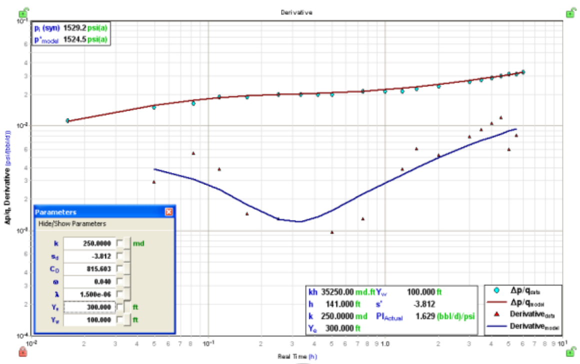

Fig.9- Dual porosity well model in well H-10

The radius of investigation at 20 minutes is 220 ft. and after 6 hr which is the duration of this test, the disterbance reaches to 930 ft.

Water oil contact and gas oil contact along with well H-10 producing interval in year 1990 is shown in Fig.10. this figure shows that fluid around well is single phase in the reservoir conditions.

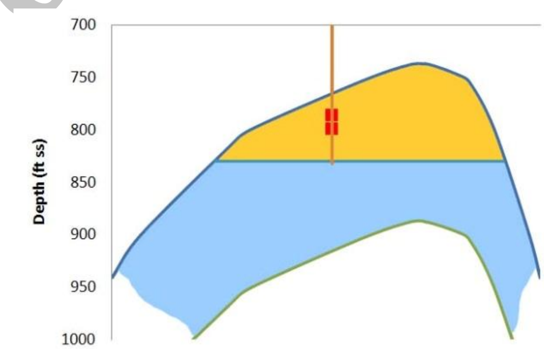

Fig.10- Water oil contact and gas oil contact in Well H-10 in 1990

The well completion schematic is shown in Fig.11

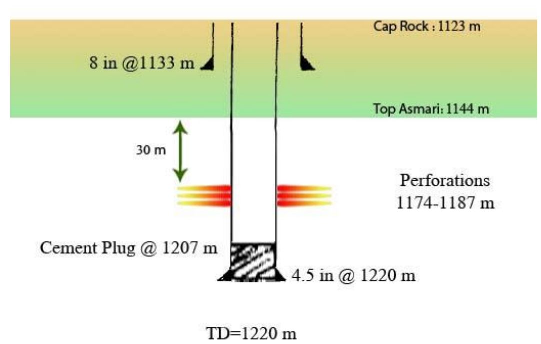

Fig.11- Well H-10 completion schematic

The well condition during flowing is shown in Fig-12. The well flowing pressure is almost a straight line, but the fluid gradient curve shows that at the bottom of the well at depth about 900 m the fluid gradient starts to decrease less than 0.3 which is the gradient of oil and it means that at this depth the gas is liberated from oil and the fluid become lighter. The bubble point pressure is 1265 and at this pressure the bubbles of gas will release from the oil.

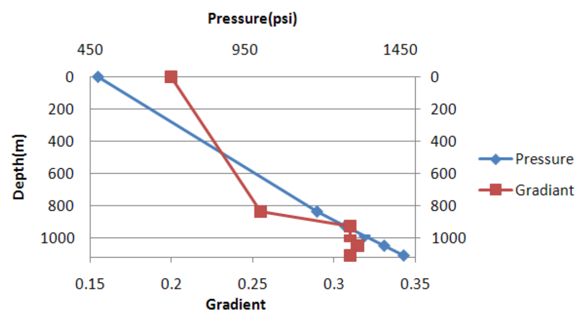

Fig.12- Well flowing pressure and fluid gradient in 1990

The static well pressure and fluid gradient is shown in Fig-13 and it shows the separation of three phases. The bottom of the hole the last point shows a water gradient and it shows that water is accumulated at the well bottom.

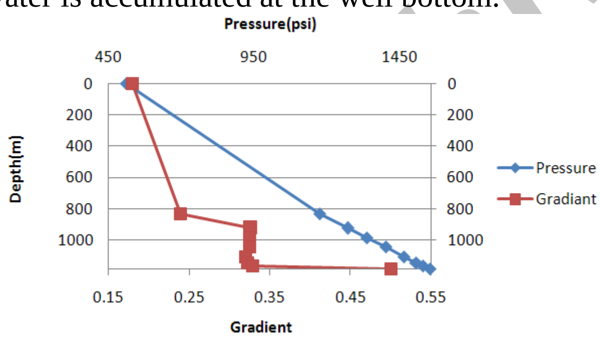

Fig-13- Well static pressure and fluid gradient in 1990

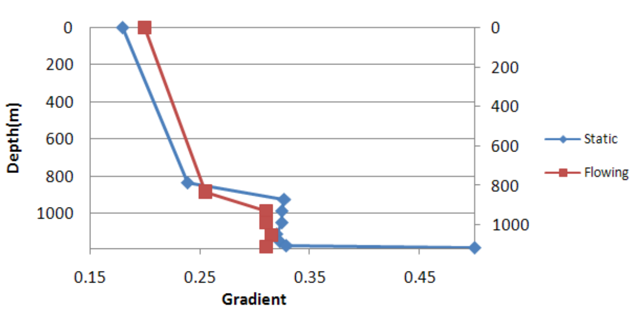

Fig-14- Fluid gradient in shut-in and flowing conditions.

The comparison between fluid gradients in flowing and static condition is shown in fig-14.

Case Study 2

After 5 years (1995), well testing has done on this well and in the build up test and after shut in the well, the pressure increased but after 45 minutes the pressure declines. This is shown in Fig.15.

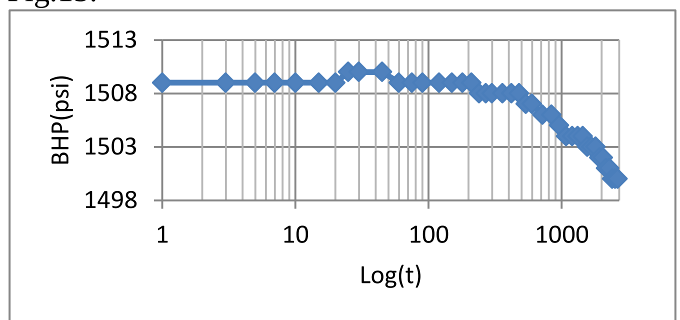

Fig.15- Bottomhole pressure declines after 20 minutes

Water oil contact and gas oil contact along with well H-10 producing interval in year 1995 is shown in Fig.16.

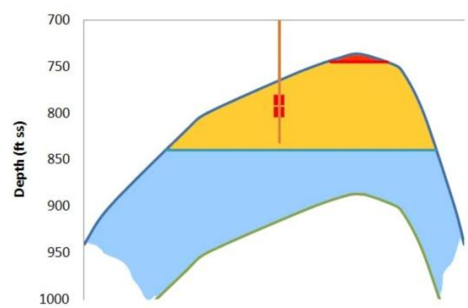

Fig.16. Water oil contact and gas oil contact in Well H-10 in 1995

The well condition during flowing in year 1995 is shown in Fig-17.

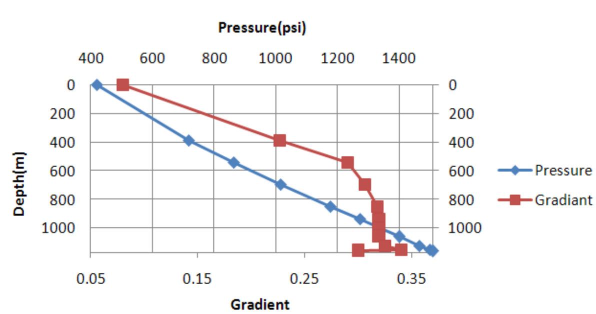

Fig-17- Well Flowing Pressure

The well condition during shut-in condition in year 1995 is shown in Fig-18.

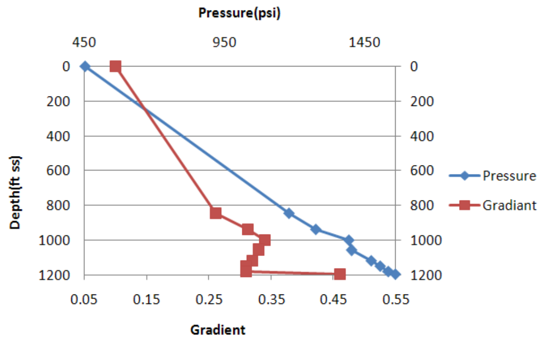

Fig-18- Well Static Pressure

Case Study 3

In the third case the effect of gas injection has reached near this well.Water oil contact and gas oil contact along with well H-10 producing interval in year 2010 is shown in Fig.19.

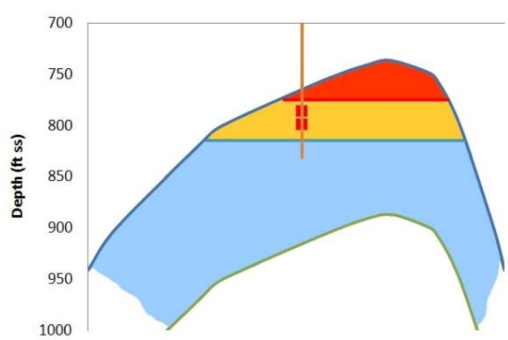

Fig.19- Water oil contact and gas oil contact in Well H-10 in 2010

The well test data in year 2010 is shown in Fig-20 . This data shows that after shut in the well, pressure builds up from 1500 psi to 1509 psi and remains constant for 24 minutes and then increased with showing a hump.

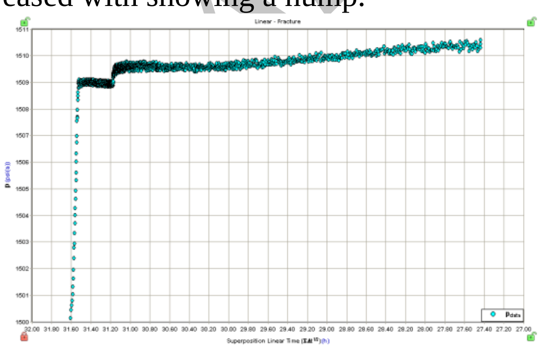

Fig.20- Build up test in year 2010

Log-log plot of the build-up test is shown in Fig.21 and it shows phase segregation as explained in Fig.5.

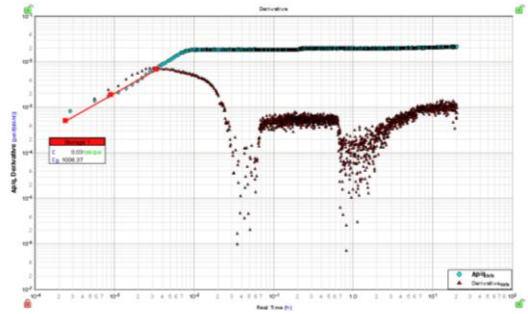

Fig.21- Log-log plot of the build-up test showing phase segregation

While gas production usually causes a temperature decrease, water entry results in either warming or cooling of the wellbore. Warmer water entry is a result of water flow from a warmer aquifer below the producing zone (water coning). In contrast, produced water can be cooler than produced oil because of differences in the thermal properties of these fluids. If both oil and water are produced from the same elevation, oil is heated more by friction while flowing in a porous medium than water is resulting in the produced water having a lower inflow temperature than the oil. Water entry by coning is relatively easy to detect from the temperature profile because of its warmer inflow temperature, but water breakthrough from the same elevation as the oil may not be obvious.

Gas entries reduce the wellbore temperature, and water entries increase the temperature(see Fig.22). The inferences are also qualitative. There is no means to determine the rate of water entry, for example. To optimize well performance, we need a better method to identify water or gas entries.

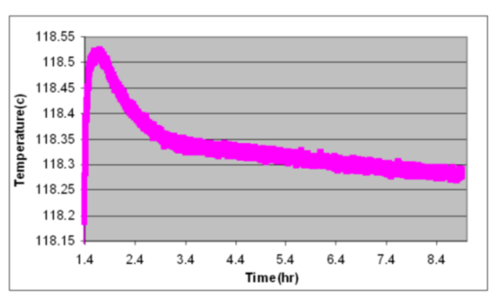

Fig.22- Temperature reduction during build up test

The well condition during flowing in year 2010 is shown in Fig-23.

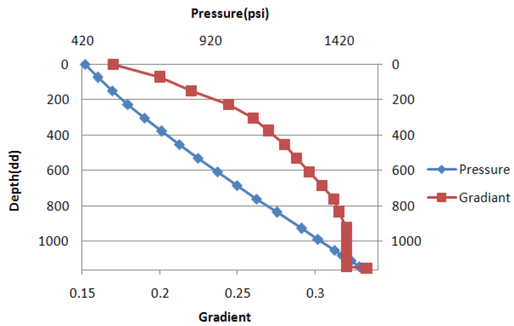

Fig-23-well flowing pressure in 2010

The well static condition in year 2010 is shown in Fig-24.

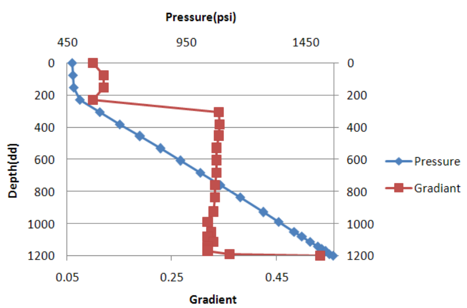

Fig-24- Well static pressure in 2010

RESULTS AND DISCUSSION

The results of studying three cases shows that in the first case the fluid is single phase and well test result are in good quality without any anomalies. However, second and third cases show that the fluid in the reservoir conditions is in two and three phase region near wellbore. This causes fluid redistribution and phase segregation in the build up test data and make the well test analysis more complex.

CONCLUSIONS

It can be concluded that in some cases in highly fractured reservoirs that has not a strong aquifer with high pressure, gas injection causes the level of water oil contact and gas oil contact go lower and this affects pressure build up tests and make the analysis of the results become more sophisticated.

KEYWORDS
Gas injection, Wellbore storage, gas-oil ratio

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