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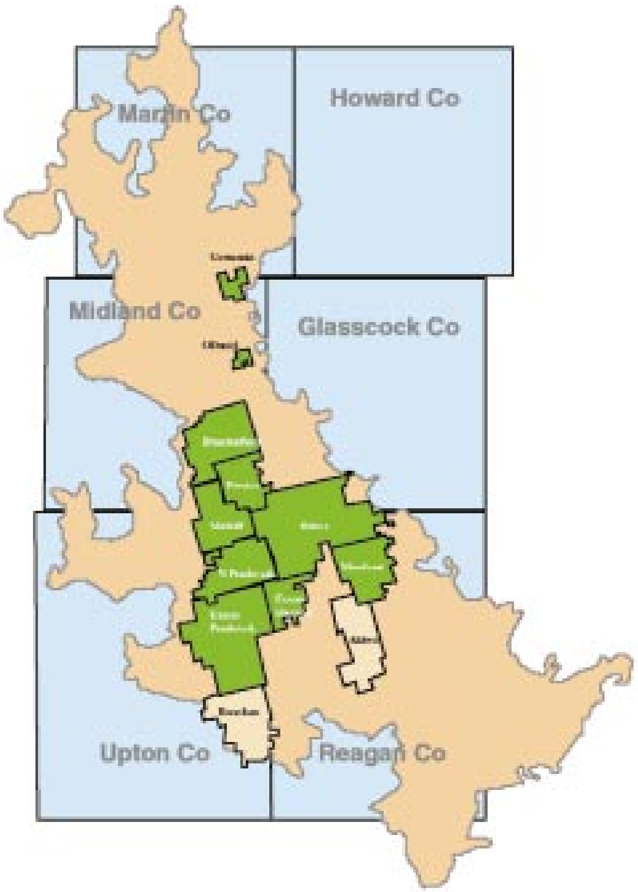
Characterization of the Dynamic Fracture Transport Properties in a Naturally Fractured Reservoir

In characterizing and modeling the performance of naturally fractured reservoirs (NFR), fracture length and fracture connectivity (permeability) are often assumed to be constant. ***In other words, total effective permeability is usually assumed to be constant.*** A number of field tests done on Spraberry Trend wells suggest this assumption is *not* always true for NFR.



Pressure transient tests and decline analyses have been used to determine permeability, skin, fracture connectivity and average reservoir pressure for the Spraberry Trend reservoir of West Texas (Figure 1). It has been hypothesized by L. Elkins[1] that fractures open and close due to pressure effects. In order to better understand these effects and fluid movement pathways, a number of specialized pressure transient tests have been conducted and analyzed in the E.T. O'Daniel Unit of Spraberry. This included constant pressure decline rate tests, build up tests, step-rate tests, falloff tests and a multiwell interference test, carried out so as to minimize the risk of induced fractures which can cause reduced sweep efficiency and fluid losses to other non pay zones. Results indicate that fracture systems are very stress sensitive in the Spraberry formation, with fractures opening and the effective permeability increasing at high injection rates (in addition, reservoir flow simulation has also confirmed that permeability is stress sensitive).

Stress Sensitive Fractures

The breakdown fracture pressure at

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inside . . .

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Spraberry or in any NFR is primarily a fracture initiation pressure through unfractured rock. In unstimulated, unfractured wells the fracture breakdown pressure is higher than the fracture propagation pressure. In Spraberry it is fracture initiation through drilling damage near the wellbore that allows for connection of natural fractures. In this case the hydraulic fracturing is due to water injection. Even after the water injection is stopped, the mechanically closed fracture will have high fracture conductivity due to mismatched fracture surfaces and formation particles propping open the fractures.

The step rate test (Figures 2) showed that the formation breakdown pressure occurred at 3017 psia when injection rates were at 200 bbl/day. Higher injection rates merely extend the fracture length. The pressure decreases after the breakdown pressure is reached, despite the constant injection rate. When the injection rate increased from 1000 bbl/d to 2200 bbl/d the injection pressure rose by only 30 psi. This is due to the opening and connecting of natural fractures. Secondary fracturing occurs when primary fractures cross secondary fracture offtrend systems as shown in Figure 3. The fluid can penetrate relatively deep into the ontrend (NE-SW) and offtrend (NW-SE) natural fractures when the bottomhole injection pressure gradients are close to hydrostatic gradient (0.43 psi/ft).

The results of the buildup/falloff tests further substantiate the stress sensitive nature of Spraberry fractures. During the buildup tests, the bottomhole pressures did not exceed about 1000 psia. This pressure is lower than fracture extension pressure, so rather than being dilated and connected, the fractures are probably constricted and unconnected. Because of this, the matrix is the dominant system through which pressure transients can travel, and hence an effective matrix (water/oil) permeability such as the 0.01 to 0.03 mD measured here is actually more representative of the matrix permeability. Note that constant pressure tests (decline rate analysis) showed lower permeabilities of 0.2 to 0.9 md. Yet during the interference and falloff tests, the tests determined effective "matrix" permeability was much higher — in the 3 to 14 md range. It is probable that injection pressure opened both offtrend and ontrend fractures, leading to higher effective permeability. For more detail read reference 2.

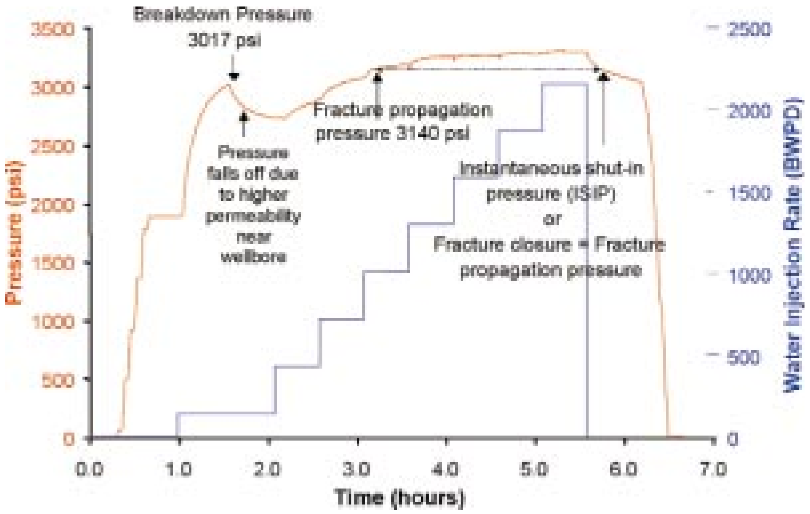

FIGURE 2: Well 47 Step Rate Test Profiles showing breakdown pressure, fracture propagation pressure and fracture closure (instantaneous shutin pressure)

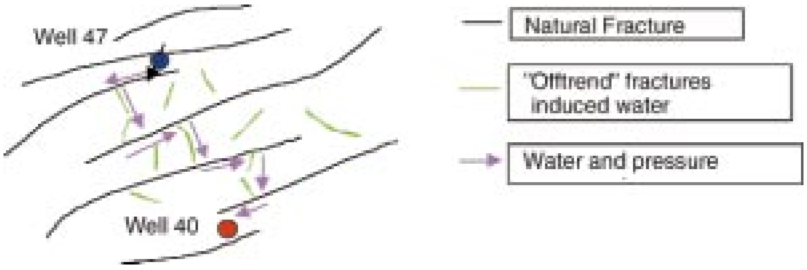

FIGURE 3: Direct Fracture Causes Pressure Response at Well 40

Conclusions

In summary, we can make the following conclusions regarding hydraulic fracturing and fracture characteristics in the Spraberry reservoir:

Assuming a constant permeability for this reservoir leads to very poor reservoir description.

Fractures are definitely stress sensitive. At reasonably high injection rates, fractures open up and the effective permeability of the system is in the 2 to 15 mD range.

During production or in low pressure areas, effective permeability is governed primarily by matrix permeability. The matrix permeability is generally in the range of 0.01 to 0.1 mD.

Generally, the Spraberry formation's parting pressure (opening and closing pressure) is in the range of 2900 to 3200 psia. This leads to a very small "frac" gradient of 0.4 to 0.45 psi/ft. Continued waterflooding at pressures near that range open up and connect short, regional fractures. The fracture gradient is generally quite

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Material Balance for Multi-layered, Commingled, Tight Gas Reservoirs

A simple spreadsheet model has been developed to estimate Original Gas In Place (OGIP), layer productivity and recoverable reserves for wells with commingled production, completed in multi-layered tight gas reservoirs. Differentiating the productivity between multiple layers of contrasting permeability is old technology. This model, however, replicates the observed material balance trend while also honouring total well production data by varying layer properties. The P/Z trend of the higher permeability layers and lower permeability layers is mapped to "envelope" the productivity index (PI) weighted P/Z curve that is used to match historical data.

This technique has been made applicable to the multi-layered reservoir environment by grouping the various kh terms, from all "high permeability" layers, into one model layer and all "low permeability" kh values into the "tighter" model layer. Published literature[1] has already shown that the generation of the layer P/Z curves is applicable to reservoirs with permeability in the range of 0.1 to 10 md. The model has been successfully applied to match and predict the productivity for various wells in Cooper Basin fields.

Methodology

Curvature in a material balance plot for a typical Cooper Basin (SE Australia) reservoir is attributed to water influx, differential depletion or both. The PI weighted material balance technique is applicable where differential depletion occurs. Other pre-requisites to this technique include:

- Reservoir layers must be isolated, ensuring no crossflow within the reservoir (e.g. coal or shale barriers).
- The well must not have been shut-in for extensive periods, allowing pressure equalization through the wellbore.
- The kh contrast between layers must not be significantly more than one order of magnitude.

The first two points ensure conditions of differential depletion are met, however the third point is less intuitive and will be explained with application of the PI weighting function. Essentially, the match is difficult to achieve as the permeability contrast approaches two orders of magnitude.

If differential depletion in the multi-layered reservoir is not recognized, the classical P/Z curve may be applied in ways that lead to erroneous OGIP volumes. Early time data will use a straight-line extrapolation, under-estimating OGIP. Alternatively, a line of best fit may be attempted to yield an OGIP value that does not honor early or late data. Finally, extrapolation of the last few data points usually over-estimates OGIP.

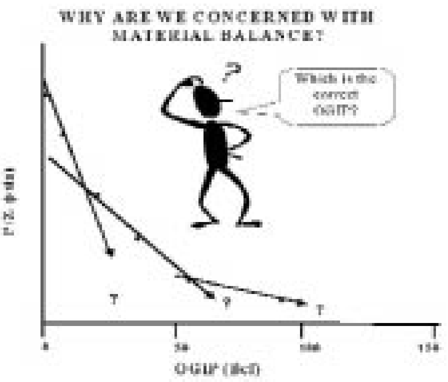

FIGURE 1: Curved P/Z Plot

This phenomenon will occur where permeability usually varies by at least an order of magnitude between layers. The layers are separated by a flow barrier (i.e. shale or coal) and therefore deplete independently in proportion to their respective productivity indices.

Considering rock properties and skin change relatively little over time, the pressure depletion in each layer becomes the primary parameter controlling layer productivity.

During the *early-transient* period, the fractional production rate from each layer is approximately equal to the ratio of the flow capacity of each layer to the total reservoir flow capacity.

As the reservoir behavior passes into the late-transient period, the fractional production rate from each layer changes. At *pseudo-steady state*, the fractional production rate from each layer is proportional to the ratio of the pore volume x compressibility product of each layer to the total reservoir pore volume.

To obtain a more accurate prediction of OGIP, the challenge was to develop a "Layered Material Balance" spreadsheet that matches actual data by averaging P/Z curves, for representative high kh and low kh layers, with an appropriate "weighting" factor. The weighting factor is

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close to hydrostatic pressure gradient.

Long term water injection does create very long fracture systems in which water can move very fast. However, many shorter fractures also interconnect to form a well-connected, extended fracture system. Once water injection is stopped, fractures can close and disconnect to some degree.

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Material Balance for Multi-layered, Commingled, Tight Gas Reservoirs . . . continued

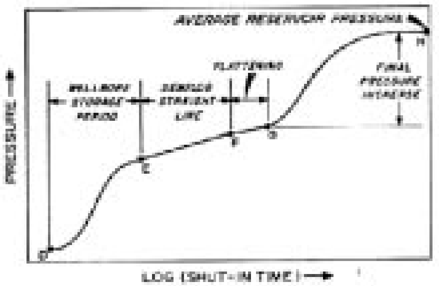

FIGURE 2: Generic Buildup Profile for a Layered Reservoir

applied to respective layer productivity indices.

Buildup Response in Layered Reservoirs

Pressures measured from buildup analyses are inherently false as the time required to reach equalization between differentially depleted layers is much longer than the typical shut-in period of a buildup test.

Pseudo-steady state flow generally begins much later in a commingled system than in the equivalent single-layer system because of the complex variation in flow contribution of each layer and the different times required for boundary effects to be felt.

Figure 2 shows a typical dimensionless Horner plot for a two-layer system and displays the well established characteristics discussed by Lefkovits *et al*[2]. Section EF is the initial semi-log straight line from which $(kh)_t$ can be determined. Section FG reflects the leveling-off of the buildup trace analogous to a single-layer system attaining static pressure. This period is followed by a final rise in the pressure buildup trace that reflects the pressurization of the more depleted layer. Point H represents the average pressure of the system. Note that the average pressure is based on the pore volume-compressibility product of the two layers and is realized only after crossflow (through the wellbore) diminishes between the tighter, less depleted layers, to the more permeable, more depleted layers.

This buildup response was readily replicated with a three-layer simulation model (with Cartesian coordinates) with typical parameters observed in a Cooper Basin well.

- Model size = 4000’ x 4000’ x 50’
- kh_1= 50 md-ft
- kh_2= 5 md-ft
- An impermeable layer separates the two permeable layers.
- Porosity = 10%, S_w = 25%
- OGIP = 10.2 Bcf per layer
- Gas rate = 2 MMcfd

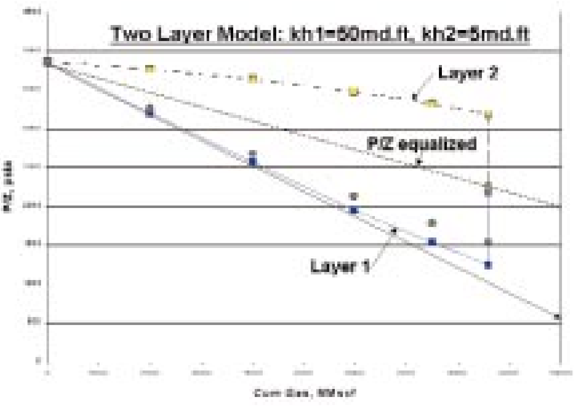

FIGURE 3: Layer Pressures and Equalized Pressure

In this example some 8.5 Bcf was produced before the final shut-in. The corresponding buildup curve replicates the generic buildup profile for a layered reservoir. Note that approximately 100 years is required before the pressures equalize between layers.

Prior to the final shut-in, the well was shut-in five times for 1-week buildup periods, usually every two years, in the simulation model. The pressure profiles of the two average layer pressures form the “pressure envelope” (Figure 3). Buildup points represent the extrapolated shut-in pressure, determined from pressure transient analysis and confirm the close correlation to the high permeability layer. The final buildup was for a duration of 100 years to obtain an equalized P/Z point for the material balance plot.

The line drawn between “P/Z equalized” and the initial P/Z point is the straight line material balance plot that extrapolates to the true, total system, OGIP.

The difficulties in predicting OGIP in multi-layered reservoirs are prevalent in both material balance and decline analysis techniques. As already discussed, the buildup pressures do not yield a straight line on the material balance plot. The plot would under-estimate OGIP at early times and over-estimate OGIP during the latter portion of the wells’ productive life. Similarly, with decline analysis, semi-log extrapolation of early rate vs. cumulative production data will under-estimate recoverable reserves. Extrapolation of late rate vs. cumulative production data, with and empirically derived hyperbolic “b” (decline) factor, may over-estimate recoverable reserves.

A more powerful method of determining OGIP is attained if we combine the two techniques. A unique, simultaneous match of the P/Z and cumulative production history is achieved by modifying the OGIP

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Material Balance for Multi-layered, Commingled, Tight Gas Reservoirs . . . continued

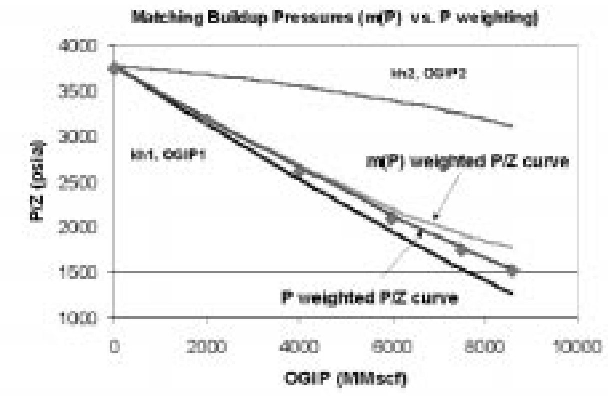

FIGURE 4: Establishing the Weighting Function

and productivity index for each layer. The material balance and productivity for all, or any single, layer(s) is included in the spreadsheet model.

The "Weighted" P/Z Curve

Recorded buildup pressure of a well completed in a multi-layered reservoir closely approximates the pressure in the high permeability intervals. We attempted to duplicate measured pressure by proportioning the pressure in each of the two representative layers to generate a productivity index weighted P/Z curve. Figure 4 shows four curves. The upper and lower curves represent the "pressure envelope" or low permeability and higher permeability layer pressures, respectively. The two middle curves, used to attempt a match of recorded buildup pressures, are the productivity index weighted P/Z curves. Recall that productivity, in the gas equation, is based on the difference in pseudo-pressures and not pressures. Pseudo-pressure has units of P^2/uZ. We found that the P^2 term was too sensitive as a weighting function and therefore utilized a P term.

When using the pressure difference, rather than pseudo-pressure difference in the weighting function, we achieve the match shown by the lower of the two middle curves. The gas flow equation justifies the use of a P (pressure) term when pressure gradients are low, as is the case when proportioning with respect to pressure gradients in a tight gas reservoir.

For our purposes, use of the "P term" in the productivity index facilitates the history match in the latter period of the P/Z curve and does not compromise the history match during the earlier portion of the P/Z curve (i.e. replicates match with "P^2 term").

Conclusions

Curved P/Z plots, resulting from differential depletion in multiple, isolated reservoir layers in the Australian Cooper Basin, has been replicated with a unique matching technique. "Higher" permeability and "lower" permeability layers, of a multi-layered single phase (gas) reservoir, are consolidated into a two layer model so that the depletion from these representative layers could be matched with a productivity index weighted P/Z curve. The technique can be successfully applied where the permeability contrast between the higher and tighter layers does not exceed an order of magnitude, there is no crossflow occurring in the reservoir and the well has not been shut-in for extended periods (allowing crossflow in the wellbore).

Simultaneous matches of the material balance and production trend (rate or cumulative production vs. time) are obtained to ensure a representative value of OGIP and kh is generated for each of the two layers.

This technique substantiates the phenomenon of productivity index weighted shut-in pressures and applies a method to quantify this phenomenon. Any operational changes (i.e. stimulation, additional compression, re-perforations) will affect the productivity index of each layer and can therefore also be captured by this material balance technique. After achieving a history match, the developed spreadsheet can be used to generate a total well forecast. Alternatively, forecasts can be obtained for each layer, simultaneously generating the varying production allocation factors.

For more details read reference 3.

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